UNC0678 – Analytical support

Ofgem

20 December 2019

REPORT

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Contents

1. INTRODUCTION

Ofgem commissioned CEPA to conduct an analysis of the costs and benefits of the modification proposals that have been raised by the industry in relation to UNC0678, which propose amendments to the Gas Transmission Charging (GTC) regime. This report summarises the findings from our quantitative and qualitative analysis.

National Grid Gas Transmission (NGGT) levies network charges for the use of the National Transmission System (NTS) in accordance with the NTS charging methodology, which is contained within the Uniform Network Code (UNC). Under the current arrangements, network users pay for the 'right' to flow gas onto (entry) and off (exit) the NTS. These entry and exit rights are purchased separately via auctions, which are subject to minimum reserve prices. The reserve prices are derived from a reference price, which is determined using a long-run marginal cost (LRMC) based reference price methodology (RPM). The LRMC methodology is intended to be an investment-based approach, which takes into account the hypothetical cost of expanding the network at each entry and exit point.

Ofgem concluded its Gas Transmission Charging Review on 13 November 2015, proposing two key changes to the gas transmission tariff arrangements, both of which have yet to be implemented:

- To introduce "fully-floating" capacity charges for long-term capacity products at both interconnection points (IPs) and non-IPs, with the exception of storage facilities;[2] and

- To reduce reserve price discounts applicable for short-term entry capacity products.

More recently, Regulation 460/2017 (TAR NC) entered into force on 5 April 2017. This establishes a network code on harmonised transmission tariff structures for gas. The objectives of TAR NC are to contribute to market integration, to enhance security of supply and to promote interconnection between gas networks. It seeks to increase the transparency of transmission tariff structures and the procedures by which they are set. TAR NC requires the revenues associated with transmission services to be recovered via capacity-based transmission tariffs, which should be cost-reflective and predictable.

Both developments imply a significant change from the status quo arrangements in Great Britain. In addition to introducing 'fully-floating' capacity charges and reducing reserve price discounts, the requirement for capacity-based charges represents a significant departure from the current arrangements, in which the majority of revenue is recovered from commodity-based charges.

UNC0621 was raised by NGGT in June 2017 in response to these developments. The UNC0621 Working Group developed ten alternative modification proposals. The Final Modification Report[3] was submitted to Ofgem on 24 July 2018. After carrying out a detailed assessment of UNC0621 and the alternatives raised, in December 2018, Ofgem decided not to accept any of the proposed modifications, based on its view that none of the proposed modifications was compliant with TAR NC.

In January 2019, NGGT raised UNC0678, stating that it was seeking to introduce GTC arrangements that produce stable and predictable transmission charges and ensure compliance with TAR NC. UNC0678 aims to amend the GTC regime to better meet the relevant charging objectives and customer/stakeholder-provided objectives for gas transmission tariffs. Modification UNC0678 has been discussed by the UNC0678 Workgroup, and ten alternative proposals (UNC0678A/B/C/D/E/F/G/H/I/J) have been raised to accommodate the various points of view of the workgroup members.

[2] 'Floating' means that the price paid by a user in the auction will 'float' up or down where NGG under- or over recovers its allowed revenue in the year the capacity is used.

[3] See: UNC0621 Final Modification Report, July 2018.

In this report, we set out our analysis of the costs and benefits of UNC0678 modification proposals in support of Ofgem's impact assessment. In addition to our analysis, Ofgem will also consider wider objectives, including its tariff setting principles, the relevant UNC code objectives and its principal duties in determining a preferred option.

The remainder of the report is set out as follows:

- In **Section 2**, we summarise the methodology that we employed to analyse the modification proposals.
- In **Section 3,** we summarise the results from our quantitative analysis, focusing on changes to tariffs, revenues and bill impacts.
- In **Section 4**, we consider the potential for impacts on investment and closure decisions, and the potential strength of the incentive for market participants to invest in bypass pipelines to avoid the use of the NTS.
- In **Section 5**, we provide qualitative analysis of the potential impacts of tariff arrangements on security of supply and the environment, as well as considering the possible implications of the Government's net-zero targets.
- **Section 6** presents the conclusions of our analysis.
- We provide charts showing the full set of results in **Appendix A**.
- We provide data tables for detailed results in **Appendix B**.
- In **Appendix C**, we provide a more detailed description of the gas and electricity market models used for the analysis.

2. METHODOLOGY

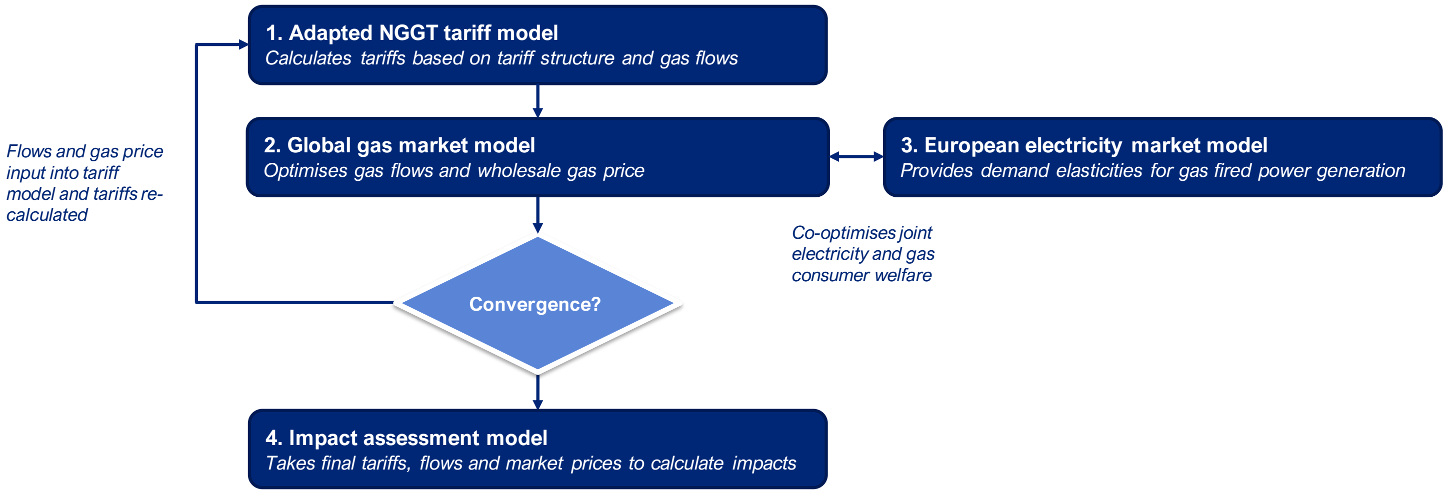
In this section, we summarise our modelling approach used to analyse the modifications proposed under UNC0678. We also summarise the key assumptions used in our modelling and their potential impacts on results.

2.1. Overview of modelling approach

We use four interacting models to consider the range of impacts of UNC0678 and its alternatives. These are:

1. **A gas transmission tariff model**: Originally designed by NGGT and adapted by us, used to calculate changes in tariffs at each entry and exit point under each of the options.
2. **Our wholesale gas market model:** We use this model to simulate gas flows and market outcomes resulting from changes to gas transmission tariffs.
3. **Our wholesale electricity market model:** To capture interactions between the gas and electricity markets, we use this model to determine the impacts resulting from changes to gas transmission tariffs on gas-fired power generation and on electricity market prices.
4. **An impact assessment model:** This model brings the tariff, flow and market modelling results from each of the above models together to estimate distributional and market-wide impacts.

Figure 2.1: Summary of modelling approach



We adapted NGGT's gas transmission tariff model[4] to determine the impact of each proposed modification on tariffs at every entry and exit point on the system. However, changes to tariffs will likely impact the behaviour of network users, for example those with elastic demand and the marginal sources of supply. The tariff model does not include the functionality to model changes to flows. Therefore, to incorporate user behaviour impacts, we use a gas market model, which takes tariffs as an input and models the flows at each point based on market fundamentals.

An electricity market model is used to provide demand elasticities of gas-fired power generators. This model also allows us to measure gas-fired power generation in the electricity market and estimate impacts on the electricity market price.

As users of the gas network are likely to book capacity on the system based on their expectations of the amount of gas, they will flow[5], tariffs will not only affect flows, but flows will also impact on tariffs. To determine an equilibrium (i.e. a state where flows and tariffs are relatively stable), we need to assume some relationship between flows and

[4] These adjustments are set out in Section 2.1.1.

[5] Particularly if making use of daily, within-day and interruptible capacity products.

capacity bookings (explained in Section 2.1.1), and iterate between the tariff and gas market model in order to seek convergence between the two.[6]

Gas years and scenarios

To understand impacts in the short and medium term, we select three gas years in which we model the options. We also choose two scenarios from National Grid's 2019 Future Energy Scenarios (FES)[7] to assess whether the impacts differ depending on the forecasted use of the gas system in future years. The table below summarises the gas years and FES scenarios used:

Table 2.1: Gas years and scenarios modelled

Gas year	Key considerations
2022/23	Ofgem are aiming to introduce reforms arising from UNC0678 for gas year 2021/22. Studying impacts in the period 2022/23 allows for consideration of near-term impacts after the market has had some time to adjust to the new tariff arrangements.
2026/27	2025 represents the deadline by which all unabated coal-fired power stations will be completely phased out. The choice of gas year 2026/27 reflects this change in generation mix. In practice, the number of coal plants still operating by this deadline is likely to be low.
2030/31	Studying this gas year allows for the study of medium- to long-term implications of different gas and electricity market scenarios. By 2030/31, the trajectories of gas demand under the two modelled scenarios are significantly different, therefore representing the possible range of tariffs under the new arrangements.

We use the Steady Progression (SP) and Two Degrees (TD) FES scenarios, as these represent relatively high and low levels of gas use, respectively. Under SP, in line with energy demand more generally, gas demand initially declines slightly with the lowest demand observed in the years 2030-40. Following this, gas demand starts to rise again due to gas use for transport, blending of hydrogen and carbon capture and storage which allows for growth in demand from gas-fired power stations.

The fall in total energy demand and gas demand is initially more pronounced under the TD scenario in which there is greater ambition for energy efficiency and to move away from gas-fired power generation. While demand from domestic, non-domestic and power generation customers continues to decline out to 2050, significant production of hydrogen from gas leads to growth in total gas demand from approximately 2035 onwards.

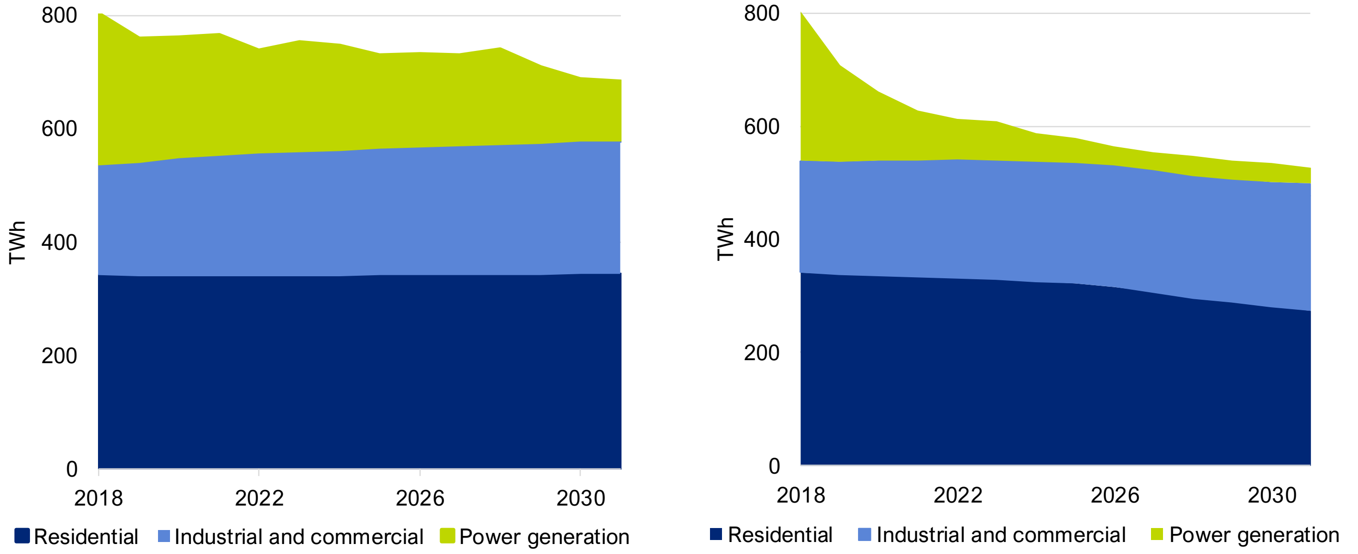
Under both TD and SP, UK continental shelf production of gas increases slightly in the early 2020s after which production steadily falls. Production in Norway declines in all scenarios as gas demand falls. NGGT set out that LNG flows and interconnection supply and demand are based on global and continental gas prices. Higher levels of LNG flows are observed under the TD and SP scenarios in comparison to other scenarios given more variable demand for gas throughout the year. In the longer term, other sources of supply such as shale gas and biomethane start to make contributions to supply. Shale gas supply emerges in the early 2030s under SP but is not sustained.

It is important to note that our wholesale gas model calculates many supply and demand variables endogenously. This includes production from all supply sources and demand from gas-fired power generation. Our endogenous calculation of supply and demand variables are maintained within the ranges set out for each scenario.

[6] As a rule of thumb, we considered that the results converged where the tariff at any of the entry and exit points modelled in the gas market model did not change by more than 1% from one iteration to the next. In practice, we limited the number of iterations to three. Where convergence was not achieved, we re-ran the tariff model to ensure revenue recovery, and then used the final set of tariffs to assess impacts.

[7] See: National Grid, Future Energy Scenarios, July 2019

Figure 2.2: Gas demand under FES Steady Progression (left) and FES Two Degrees (right)



Source: National Grid, FES 2019. For simplicity, we have included transport and hydrogen gas demand within the 'Industrial and commercial' category.

In June 2019, the UK became the first major economy in the world to introduce laws to reduce net carbon emissions to zero by 2050. The timing of the announcement did not allow National Grid to develop a fully formed scenario within the FES, but they did include a Net Zero sensitivity. Under this scenario, National Grid set out that natural gas would remain crucial to supply but would only be used with CCUS as a key input to hydrogen production and industrial processes. Residential gas heating demand would decline as other technologies (hydrogen and electricity) would be used for home heating.

While the magnitude of change may drive quite different outcomes for gas supply and demand by 2050 (e.g. due to a greater role of gas with CCUS and hydrogen), we would expect the scenario to be most similar to TD out to 2030. We comment qualitatively on the potential impacts of a Net Zero scenario in Section 5.1.1.

As it is more consistent with the Government's legally binding objective of net-zero emissions by 2050, we focus on the TD scenario for the purposes of analysis. We use the SP scenario as a sensitivity allowing us to identify the sensitivity of results to changes in GB and global gas demand, and in turn on GB and global gas prices.

Modification options

UNC0678 and its alternatives, in combination with the status quo, constitute a total of 12 charging options.[8] In line with the agreed scope of the project, we consolidated some proposed modifications into a single option, given the similarities between their main characteristics.

We define the NOC methodologies as follows:

- **NOC Methodology 1**: The methodology included in UNC0678 B. Reserve prices are established with reference to the ratios of straight-line entry-exit distance to entry and exit CWD values with application of a "System Utilisation Factor".

[8] Eleven proposed modifications under UNC0678 - see UNC0678 Final Modification Report, May 2019, Tables 4 and 5, p.14-15 – plus the current charging arrangements i.e. the 'status quo'.

- **NOC Methodology 2**: The methodology included in UNC0678 D/G/H/J. This takes the existing optional commodity charge (OCC)[9] formula and adjusts it by RPI, as well as converting the commodity-based tariff into a capacity-based tariff.
- **Wheeling methodology**: The methodology included in UNC0678 I. The design of the NOC is the same as for NOC Methodology 2 but applies an eligibility restriction in which only entry and exit points separated by a zero km distance are able to use the NOC product.

We consolidated the four modifications which include an NTS Optional Charge (NOC) using 'Methodology 2' into two. We modelled this methodology with both the PS and CWD RPMs. However, we did not model the two different revenue recovery exclusion options which have been proposed under each combination of options. Instead, we modelled the options with the greatest level of revenue recovery exclusions (UNC0678D and UNC0678J) and consider the impacts of a lower level of revenue recovery exclusion (under UNC0678G and UNC0678H) qualitatively.

We did not model the 'Capacity Surrender Rule' included within modification proposal UNC0678F. We consider the potential impacts of the capacity surrender rule qualitatively.

We summarise the modification options modelled in Table 2.2, presented overleaf.

[9] The OCC tariff was introduced in 1998 with the intention of providing an option for shippers seeking short distance gas transportation. It aims to avoid inefficient bypass of the NTS and can be paid by NTS users as an alternative to the standard commodity charges.

Table 2.2: Characteristics of modelled options

Option	Label in analysis	RPM	Capacity used for tariff calculation	Storage discount	Revenue recovery exclusions	Optional charge (shorthaul)	Mod (with closest alignment)	Also applies to:
Status quo	SQ	LRMC plus commodity charge	Obligated capacity	None	N/A - existing contracts are liable for commodity charges	Optional Commodity Charge		
Capacity Weighted Distance (CWD) baseline	CWD	CWD	Forecasted Contracted Capacity (FCC) by National Grid, net of existing contracts.	50%	Existing contracts	None	0678	
Postage stamp (PS)	PS	PS		50%	Existing contracts	None	0678A	
CWD with storage discount	CWD storage	CWD		80%	All Storage sites - all other existing contracts included	None	0678E	0678F: The 'surrender rule' proposed in 0678F will be considered separately
PS with storage discount	PS storage	PS		80%	All Storage sites - all other existing contracts included	None	0678C	
CWD with NTS Optional capacity charge (NOC) - Methodology 1	CWD NOC 1	CWD		50%	Existing contracts	NOC: Using 'Methodology 1'	0678B	
CWD with NOC - Methodology 2	CWD NOC 2	CWD		50%	Existing contracts	NOC: Using 'Methodology 2'	0678D	0678G: This mod is identical but only existing storage contracts are excluded from the revenue recovery adjustment
PS with NOC - Methodology 2	PS NOC 2	PS		50%	Existing contracts	NOC: Using 'Methodology 2'	0678J	0678H: This mod is identical but only existing storage contracts are excluded from the revenue recovery adjustment
CWD with Wheeling NOC and Ireland Security Discount	CWD Wheeling	CWD		50% (and 95% Ireland Security Discount)	Existing contracts	NOC: Using 'Wheeling charge'	0678I	

2.1.1. Tariff modelling

We adapted the Microsoft Excel tariff model developed by NGGT[10] for the purposes of modelling the impacts of the modification proposals at each entry and exit point. The tariff model includes all gas entry and exit points on the system. To be able model certain elements of the modification proposals, we adapted the tariff model in the following ways:

- We included functionality to reflect the three NOC methodologies,[11] their revenue recovery implications, and the impact on the tariffs of other points. We only captured shorthaul routes that were utilised in 2017/18 within our modelling. Uptake of these routes was determined based on the outputs from our market modelling.
- We adapted the revenue recovery adjustment mechanism to allow us to reflect the modification proposals. This allowed for both the exclusion of existing contracts and the exclusion of storage site bookings (both existing and new), while including all other existing contracts.
- We added functionality to allow us to model the 95% Ireland security discount.

Key assumptions

To make the modelling of modification options feasible, we incorporated a number of assumptions and abstractions. We summarise the key assumptions in Table 2.3 overleaf.

[10] See: NGGT, March 2019, Sensitivity Tool (Model) 0678 V3.1 CWD Transmission Services (21 March 2019).

[11] As described in the final modification reports. See: www.gasgovernance.co.uk/0678.

For methodologies 2 and wheeling, we also drew upon the cost functions developed by NGGT on behalf of the proposers. For methodology 1, we developed an iterative approach to setting tariffs, in line with the model developed by NGGT on behalf of the proposer. For our calculations, we utilised a modelled System Utilisation Factor (SUF), based on market modelling outputs.

See www.gasgovernance.co.uk/0678/Models for all relevant models developed as part of the UNC Panel workgroup.

Table 2.3: Summary of key assumptions

Assumption	Approach	Possible implications
Bookings and flows	For all users other than gas distribution networks (GDNs), bookings are assumed to equal to flows. This is considered appropriate given spare capacity on the system in combination with multipliers of 1 for short- and long-term capacity bookings. We assume that GDNs book to the 1-in-20 standard, in line with their interpretation of their licence.	Capacity bookings are likely to be lower than in reality, where some 'overbooking' may occur. All else equal, this will increase capacity tariffs as they are distributed over a smaller set of users. However, this assumption has a similar effect across all options. Therefore, it does not significantly affect the costs and benefits of one option relative to another.
Existing contracts	Existing contracts are utilised first. As these contracts are already in place, we assume that they will be netted off the FCC and revenue recovery requirements.	This assumption reduces the amount of new capacity bookings (FCC, net of existing contracts) relative to a scenario in which the utilisation of existing contracts is less than 100%. All else equal, this increases tariffs across all modification options. As the number of existing contracts reduce over time, the impact is likely to be greater in 2022/23, in comparison to 2030/31.
Forecasted Contracted Capacity (FCC) calculation	We do not include the historic elements (Y-2 bookings and flows) in the setting of the FCC as these would lead to systematic under recovery, which could not be computed using spot years. We instead set the FCC based on the higher of bookings (based on FES forecasts and results from our market modelling) and the volume of existing contracts.	If we included the Y-2 elements, in the presence of declining gas demand, the FCC would often be set by historic bookings or flows (using the decision rule included in the FCC methodology which would often take historic bookings as the maximum). This could lead to systematic under recovery of revenue, given that actual bookings and flows would most likely be lower than the historic values used.
Booking allocations	We assume that the proportions of different capacity products booked by users are equal to those observed in the most recent historical gas year for which data is available (2017-18). This assumption allows us to reflect the proportion of different types of bookings which are currently observed at different entry and exit points.	Under options other than the status quo, the effect is relatively limited. Given that multipliers for all standard products are set at 1, the proportions of different firm products do not impact on revenue recovery. This approach also applies to the proportion of interruptible/off-peak contract bookings. All modification proposals include a discount for interruptible bookings, but this is small (10%) so the impact on revenue recovery is likely to be limited.

		We consider that this assumption is appropriate for the status quo, as there is no reason for booking behaviour to change if the current charging arrangements continue to apply. However, combined with bookings being set equal to flows (for all users other than GDNs), this assumption can have a revenue recovery impact under the status quo, given that significant discounts are available for the daily and interruptible/off-peak products. This may be reflected in a greater proportion of revenue recovery being transferred from the capacity to commodity tariffs.
Zero-priced interruptible contracts	Zero-priced interruptible contracts are included within our assumption of the proportions of different capacity products booked. Under the modification proposals, the 10% interruptible product discount would be significantly less attractive relative to the existing discount for interruptible contracts (with a reserve price of zero). However, with the removal of a discount for the daily product, the interruptible contract may become more attractive for some users.	On balance, we consider that our assumption is likely to overestimate use of the interruptible product relative to other capacity products. This will impact on revenue recovery, proportionally pushing up the reference capacity prices for all points. At the same time, this would reduce the weighted average capacity tariff after accounting for interruptible bookings. This is likely to offset the general increase in reference capacity prices for points that tend to buy a large proportion of interruptible contracts (e.g. interconnectors). These effects would be relatively small given that the interruptible discount is 10%.
Revenue recovery requirements	We set revenue recovery requirements based on estimates set out in RIIO-1 until 2022/23, from which point we hold revenue recovery requirements constant in real terms.	Depending on RIIO-2 revenue recovery requirements, our assumption may represent an under- or overestimate in different years. This assumption has a similar impact across the modification proposals, thus should not bias the results.

2.1.2. Market modelling

The gas market model

We make use of our global gas market model to estimate the impacts of tariffs on market flows and prices. Our model simulates the gas wholesale market, using assumed marginal costs of gas production and derived supply and demand elasticities. Prices and flows are determined by minimising total cost of meeting demand, subject to a number of production, transmission and demand constraints. We provide further detail on the structure of our gas market model in Appendix B.

The electricity market model

Capturing interactions between the gas and electricity markets is important, given the important role gas-fired power generation plays in the GB electricity supply mix[12]. We have therefore coupled our global gas market model with a European electricity market model via explicit modelling of demand curves for gas-fired power stations. The electricity market model incorporates all existing generation assets in the North West Europe electricity market region and assumes market coupling to minimise costs of meeting electricity demand. Integrating the electricity and gas market models allows us to capture the interactions between the two markets. The gas market model uses elasticities of gas-fired power generation, determined endogenously within the electricity market model. Thus, this approach also allows us to estimate the impact of the proposed modifications on the wholesale electricity market. We provide further detail on the structure of the electricity market model in Appendix B.

Assumptions used in the market models

To make modelling of the modification options feasible, we incorporated a number of assumptions and abstractions. We summarise the key assumptions in Table 2.4.

[12] We note that our electricity modelling does not explicitly incorporate any of the changes which may arise in the electricity market as a result of the conclusions of the Targeted Charging Review or the Access and Forward-Looking Charges Significant Code Review.

Table 2.4: Summary of market modelling assumptions

Assumption	Approach	Possible implications
Gas-fired power generation	We introduce separate power station nodes for each power station that made use of the Optional Capacity Charge (OCC) in the gas year 2017-18.[13] For power stations that did not make use of the OCC in 2017-18, we consolidate those power stations into a single nominal node in the market model.	This allows us to model gas flows and revenues for those power stations that made use of the OCC in 2017-18. However, we can only consider the residual power stations that did not make use of the OCC in the aggregate.
Shorthaul contract pricing	SH contracts are priced at a discount to the NBP. The discount is the difference between full entry and exit tariff and the specific SH tariff.	Our analysis does not fully reflect the potentially complex commercial arrangements which may be involved in contractual arrangements relating to shorthaul.
Shorthaul routes	For options which include some form of shorthaul product, we assume that only those entry and exit points which used a shorthaul product in the last gas year (2017-18) are able to make use of the shorthaul product in future years.[14]	Depending on the attractiveness of the tariff derived under the different shorthaul product methodologies, it is possible that entry and exit points which did not use the product in the previous gas year may start doing so. Our analysis does not incorporate these potential users of the product.

[13] These power stations currently represent approximately 80% of the NTS-connected gas-fired generation capacity.

[14] This effectively represents an additional eligibility criterion for use of the NOC product in the model.

Existing contracts	Existing contracts are not included in the gas market model – i.e. their use is not included within the flow options at individual entry and exit points (but total volumes are netted off outside of the model). Inclusion of existing contract pricing at each node would require developing a new GB market model which was not feasible within the timeframe of this project.	The potential impact on the gas market price is unlikely to be material because: 1. This assumption is unlikely to affect the merit order.[15] We would expect any impact to be small in years where gas demand exceeds aggregate existing contract capacity bookings, because in these years marginal demand and supply will set the wholesale price, unaffected by existing capacity bookings. 2. Even if the merit order is affected, the impact on the market price is likely to be small. This is because the transmission tariff is a small portion of the gas market price.[16] This leads to an equally small impact on gas demand and on entry flows.
Elasticity of industrial, commercial and domestic sectors	We assume that these forms of demand are fully inelastic, save for some demand-side response at high gas prices.	For each modelled scenario and year, demand from these sectors is constant; independent of the tariff option modelled and wholesale gas price. Changes to the tariffs and wholesale gas price therefore impact on the bills for these customers without any change in demand.
No closure of power stations that made use of the OCC	We do not make any assumptions about the closure of gas-fired power generators that made use of the OCC in 2017-18 (often larger power stations). While the capacity of gas-fired generation reduces over the period considered, we do not assume that any of these generators close.	The assumption is consistent with our more general assumption that all entry and exit points remain on the system (subject to supply/demand assumptions from FES). As capacity from shorthaul power stations is fixed, the impact of this assumption therefore depends on the demand from gas-fired power stations more generally. Where demand increases, shorthaul power stations constitute a gradually decreasing proportion of power station demand. Where demand from gas-fired power stations decreases, the opposite is the case.

[15] See: Baringa, April 2019, Analysis of potential impacts of price differentials between new and existing capacity contracts.

[16] Ibid.

We also note two features of the electricity market model which may affect our impact assessment:

- The electricity market model is an 'energy only' model. It does not include the GB capacity market.
- Like the gas market model, the electricity market model is deterministic and so does not capture supply or demand shocks which may lead to short-term price spikes.

Both features may impact on the overall magnitude of electricity consumer welfare estimates, but these impacts are likely to be limited.

Where tariff options have consequential impacts on the electricity wholesale price, this may affect the revenues of electricity generators in the electricity market. Generators may try to recover any revenues which are lost due to a lower electricity price from the capacity market. Similarly, they may need to recover less revenue from the capacity market in the case that the electricity price increases. Of course, the extent to which generators can recover additional revenues from the capacity market will depend on competition in the auction. Nevertheless, under those options in which electricity consumer welfare increases as a result of a lower electricity price, it is possible that some of the benefits may be counterbalanced by higher capacity market costs. While the lack of a capacity market in the modelling may over-estimate the electricity consumer welfare benefits that exist under some options relative to the status quo, the impact is likely to be limited.

The existence of price spikes would impact on the electricity wholesale price and may also be priced into forward electricity supply contracts. This may therefore increase the level of the electricity market price relative to our modelling. We would expect this outcome to apply to all of the options being modelled however. While the precise impacts may be dependent on the supply and demand dynamics under any option, we do not identify any reason to believe that this would result in a greater impact under some options than others. We therefore consider that the relative impacts between options would not be affected to a significant extent by the lack of price spikes in the modelling.

2.1.3. Impact assessment modelling

Our impact assessment (IA) model[17] brings together the outputs from the tariff and market models to estimate the following:

- total consumer welfare, gas and electricity market impacts, as well as direct tariff impacts;
- impacts on gas bills of different consumer types;
- impacts on electricity bills of different consumer types;
- impacts on producers;
- long-run investment impacts and closure analysis; and
- impacts on carbon emissions.

As all entry points are included within the tariff and gas market models, we are able to make observations about impacts on individual shippers using those entry points. However, the gas market model consolidates exit points, other than gas-fired power stations that made use of the OCC in 2017-18, into a single node. In addition, both models represent the transmission level, and thus do not model the gas distribution network or differentiate between distribution-connected users.

We introduced consumer strata, summarised in Table 2.5 below, to measure the bill impacts on domestic and industrial and commercial (I&C) gas consumers. Impacts on power stations were estimated separately.

[17] We apply a discount rate of 3.5% and apply linear interpolation to calculate impacts in those gas years in the period 2022-31 that we have not modelled explicitly.

Table 2.5: Consumer strata in impact assessment modelling (gas consumption)

Consumer type	Approach	Estimated consumption
Domestic consumer	We consider financial vulnerability by taking the median consumption of a user in the 20% most fuel-poor households based on the BEIS National Energy Efficiency Data-Framework (NEED).	Vulnerable: 11.7 MWh/year
	Based on typical consumption levels, as defined in Ofgem's Typical Domestic Consumption Values.	Low: 8.5 MWh/year
		Medium: 12.4 MWh/year
		High: 17.3 MWh/year
Industrial and commercial consumer	Based on BEIS gas consumption statistics, we estimate impacts for LDZ-connected I&C consumers.	LDZ-connected: 149.2 MWh/year
	We used National Grid data to develop approximate median consumption for NTS-connected consumers in 2017/18.	NTS-connected: 400,000 MWh/year

The consumer strata we use for electricity consumers are summarised in Table 2.6.

Table 2.6: Consumer strata in impact assessment modelling (electricity consumption)

Consumer type	Approach	Estimated consumption
Domestic consumer	We consider financial vulnerability by taking the median consumption of a user in the 20% most fuel-poor households base on the BEIS National Energy Efficiency Data-Framework (NEED).	Vulnerable: 2.8 MWh/year
	Based on typical consumption levels, as defined in Ofgem's Typical Domestic Consumption Values.	Median: 3.1 MWh/year
Industrial and commercial consumer	Based on BEIS electricity consumption statistics, we estimate impacts on LDZ-connected I&C consumers.	LDZ-connected: 8.3 MWh/year
	Given the heterogeneity of very large gas consumers with respect to electricity consumption, we do not attempt to measure impacts on the electricity bill of these consumers.	NTS-connected: N/A

In the IA modelling, we assume that gas transmission tariffs at GDN exit points and changes in the wholesale gas and electricity prices are passed onto consumers.

2.1.4. Bypass investment analysis

The OCC product was introduced to deter users of the gas network from investing in gas pipelines which would enable them to bypass the NTS and avoid paying the transmission tariff. The OCC is an optional tariff, which is intended to reflect the fact that such users may only make use of a relatively small portion of the gas transmission network, and may therefore have an incentive to invest in bypass infrastructure in the absence of the OCC.

We performed an analysis of potential bypass incentives to provide an indication of the likelihood that bypass pipelines would be built. This analysis relies on several assumptions and simplifications and should therefore be considered as indicative only. In practice, the commercial decisions of users of the gas network in relation to bypass investment decisions are likely to be significantly more complex.[18]

We estimated the net present value (NPV) of the cost of building a gas pipeline, and compared this with the potential NPV savings of avoiding paying the applicable transmission tariff(s) for that route.[19] This allows us to assess whether the investment in a bypass pipeline would be commercially attractive within a five-, ten- and 25-year time horizon.

We estimated bypass pipeline costs by adapting a cost function developed by NGGT.[20] This cost function provides the capital and operational expenditure estimates required to construct and operate a pipeline of a certain length (in km) and size (in terms of diameter and maximum flowrate capacity).

However, we deviate from NGGT's cost function in one key area. That cost function assumes that those who invest in a bypass pipeline will flow at 100% of their Maximum NTS Exit Point Offtake Rate (MNEPOR); effectively assuming a 100% load factor. Instead, we reflect the average load factor of that pipeline over its life, using the gas flows estimated within our modelling.[21]

Assumptions used in the bypass model

To make the modelling of modification options feasible, we incorporated a number of assumptions and abstractions. We summarise the key assumptions in Table 2.7.

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[18] Decisions are likely to incorporate other factors such as risk aversion, forecasts of future demand and commercial positions in end-use markets, for example.

[19] Where a 'route' represents a specific entry and exit point combination.

[20] This cost function is broadly similar to the one developed by National Grid for the purposes of calculating the NOC in a number of the proposed modifications, as illustrated in this model: NTS OCC Methodology D-G-H-J. We adapted this model by utilising a different annuitisation factor for capital expenditure that reflects a longer project life (25 years rather than 10) and a higher real cost of capital that more closely aligns with what an unregulated market participant would be able to obtain.

[21]This is based on modelled flows under the status quo (as outlined in Table 2.7) for each of our modelled years (2022/23, 2026/27, and 2030/31), interpolating between them. We assume flows remain constant after our final modelled year. This differs from the cost function developed by National Grid, which assumes an 100% load factor for all routes.

Table 2.7: Summary of bypass investment modelling assumptions

Assumption	Approach	Possible implications
Costs of bypass	Only direct capital (capex) and operational (opex) costs are included in the analysis.	In practice, there are likely to be significant additional costs beyond those that we have included, which may deter investment in bypass pipelines, e.g. land rights, legal costs, etc. The additional risk of flow constraints, which arise from losing connection to the NTS, may also be an important factor when considering bypass. This implies that our analysis may overestimate the percentage of routes that would bypass the NTS.
Gas flows	We assumed that the demand of I&C customers is not price responsive. Flows of gas for I&C customers using the bypass pipeline are therefore equivalent to flows of gas under the status quo for a given scenario and year. We also assumed that power stations flow gas as they would under the status quo for a given scenario and year.	Following investment in a bypass pipeline, the marginal costs of an additional unit of flow may be relatively close to zero (especially where compressors are not needed over short distances). Therefore, those who do build a bypass pipeline may increase flows, allowing for payback on investment in a shorter period of time. Our assumption may therefore underestimate the percentage of routes that may bypass the NTS.
Load factors	We use modelled load factors of potential users of bypass pipelines, rather than assuming that their load factor is 100% of their MNEPOR.	The current OCC methodology, NOC Methodology 2 and the NOC Wheeling methodology assume that load factors are at 100% of MNEPOR. Our use of actual flows means that network users are less likely to invest in bypass pipelines than would otherwise be the case. Assuming that the MNEPOR is appropriately determined to reflect peak demand, we consider it more realistic to assume that those who build a bypass pipeline would maintain their existing gas consumption profile over the year, and hence continue to flow gas at their existing load factor (or close to it), rather than at 100% of MNEPOR.
Tariff that would have been paid without bypass	We assume that the capacity required for those who build a bypass pipeline would have been purchased using the cheapest tariff option available in the absence of bypass; i.e. where a NOC is available, all gas capacity would have been purchased using that product if a bypass pipeline was not built.	In practice, there may be potential constraints on the capacity available under NOC. This implies that our modelling may underestimate the risk of bypass. This also impacts our estimates of lost revenue recovery in the event of bypass. For the same reasons as discussed above, this suggests an underestimate of the amount of revenue that would be lost in the event of bypass.

Size of bypass pipeline	We assume that those bypassing the system would choose to build a pipeline which could meet their MNEPOR to cover capacity requirements.	In practice, users may make a commercial decision to build a smaller pipeline than their current MNEPOR, particularly where their current MNEPOR exceeds their capacity requirement at peak. We note that this may introduce additional risk of constraints. In the case that users did choose to build a smaller pipeline, payback time may reduce, resulting in a greater risk of bypass than our modelling suggests.
Cost of capital	We use a 7% assumed cost of capital, informed by BEIS cost of capital estimates for combined cycle gas fired power generators.	Where internal cost of capital requirements differ from this assumption, this may increase or decrease bypass investment payback time. We note that the current OCC methodology, NOC Methodology 2 and the Wheeling methodology incorporate an annuitisation factor consistent with NGGT's,[22] which assumes a significantly lower cost of capital.
Infrastructure asset life	A 25-year expected lifetime of the bypass pipeline was assumed.	Market participants may consider bypass investment based on a shorter, commercial lifetime. This would have two opposing effects. It would decrease the time period over which the capex needs to be recovered. However, it would also decrease the total opex costs that need to be recovered. We note that the economic life of a gas pipeline could be up to 50 years.

In our view, the assumption which is likely to have the most significant impact on the modelled risk of bypass is that only direct capital and operational costs are included. While some of our assumptions may imply an underestimate of the risk of bypass, we would expect the assumptions surrounding costs to outweigh this. We therefore believe that our analysis represents an over-estimates of bypass risk.

[22] The annuitisation factor is no longer contained as a separate term in NGGT's license, but it is implicit within its revenue drivers. The current OCC methodology and the Wheeling methodology use 0.10272, as originally agreed with Ofgem in 2006 (as per the UNC TPD section Y, p.18), whereas NOC Methodology 2 utilises an annuitisation factor consistent with the approach used to set the revenue drivers.

3. QUANTITATIVE ANALYSIS

In this section, we present findings from our quantitative tariff, market and impact assessment modelling. We present distributional impacts of changes to tariffs, as well as wider systems impacts which result from consequential changes to the wholesale gas and electricity market prices.

3.1. Impacts of scenarios and gas years

We present the sources of gas flows and the daily wholesale gas price over the year 2030-31 under the TD scenario and SP sensitivity in Figure 3.1 and Figure 3.2.

Figure 3.1: Gas supply sources and wholesale gas price under the status quo (TD, 2030-31)

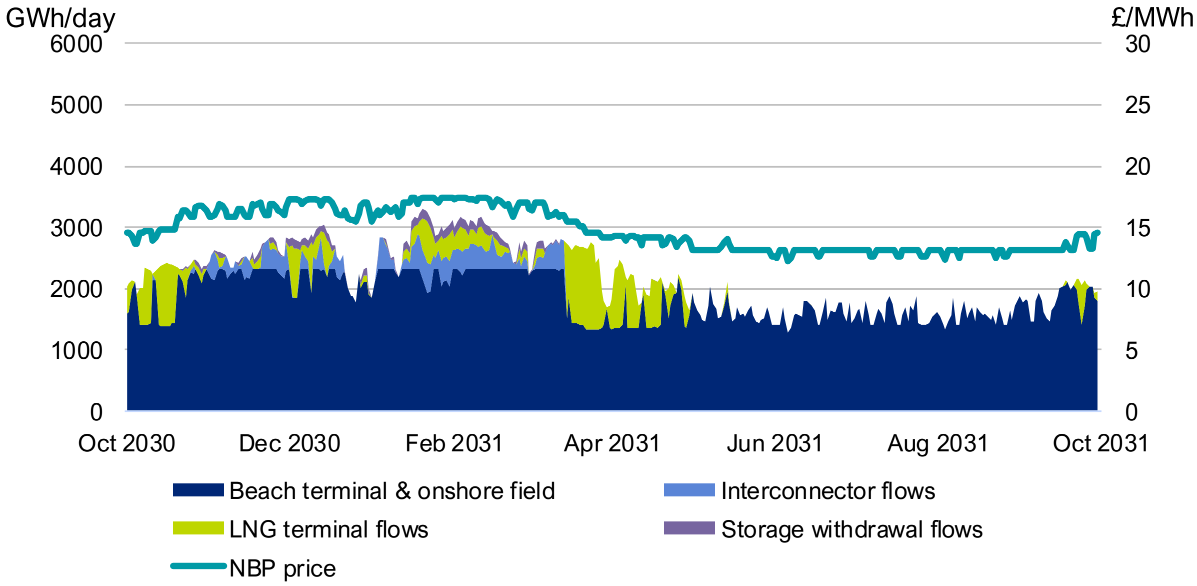
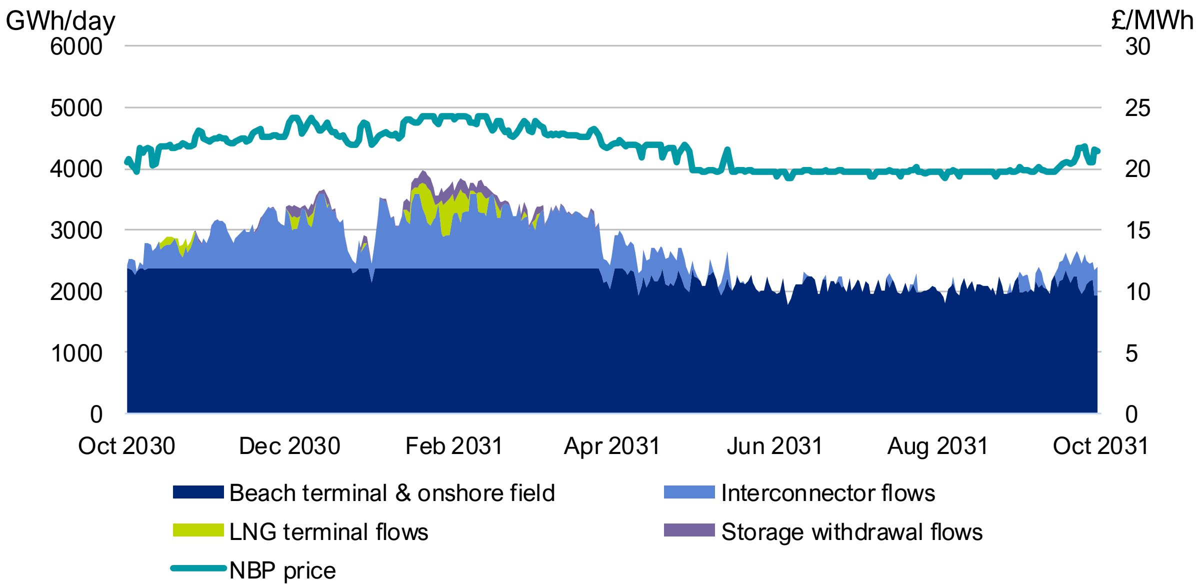


Figure 3.2: Gas supply sources and wholesale gas price under the status quo (SP, 2030-31)



We observe that the wholesale gas price is higher under the SP sensitivity, driven by both higher domestic gas demand and higher international gas demand. Global gas demand also makes LNG flows relatively more expensive, resulting in substitution for interconnector entry flows under the SP sensitivity.

Gas transmission tariffs are designed to recover NGGT's allowed revenue through tariffs set at gas entry and exit points. In our analysis, we assumed that capacity is booked to cover flows. Therefore, for a given level of revenue, the average tariff weighted by capacity bookings is only affected by the level of gas demand on the system. Higher gas demand means that revenue is spread across more capacity bookings, and hence, tariffs decrease. Likewise, where demand is lower, tariffs increase. Given that demand is lowest under the Two Degrees (TD) scenario in gas year 2030/31, tariffs are projected to be the highest under this scenario and gas year, therefore the relative impacts of the modification options in comparison to the status quo are likely to be the largest in this case.

While we did not model a net zero scenario, we would expect that paths to net zero would also involve lower gas demand by 2030, potentially in line with or greater than that observed under TD. We may therefore expect to observe tariffs which are similar or higher than that observed under the TD scenario.

In the remainder of this section, we present the results from our modelling of UNC0678 and its alternatives. In order to present the most significant potential impacts, we focus on the results of the TD scenario in gas year 2030-31, unless otherwise stated. We provide additional results from other gas years and scenarios in Appendix A.

3.2. Impacts on tariffs at entry and exit points

In this section, we summarise the impacts of different options on the capacity tariffs at entry points, exit points and combined entry and exit points (storage facilities and interconnectors[23]). We present the standard annual capacity tariff (in p/kWh/day) throughout.[24] Finally, based on the relative attractiveness of the NOC product, where included in the RPM, we estimate the proportion of network users that would likely make use of the NOC.

3.2.1. Impacts on annual tariffs at entry points

In addition to the direct impact of any change to the tariff, there are likely to be impacts on consumer welfare. We only present here the direct impact on the entry tariff itself. In Section **Error! Reference source not found.**, we consider the impacts of changes in tariffs on the consumer bill, assuming that changes to the entry tariff would be passed onto consumers through the wholesale gas price. The direction of the impact of the tariff change on the wholesale price depends on whether the marginal unit of supply receives a discount or an increase in its tariff relative to the status quo.

Average level and dispersion of tariffs at entry points under each option

Figure 3.3 sets out the average tariff, weighted by the volume of capacity bookings, at each entry point. The figure also illustrates the dispersion of tariffs[25] at entry points under each option. The TO commodity charge, which is included within the status quo, is reflected in the range of the capacity tariff presented for that option – i.e. the capacity tariff range is 'uplifted' to reflect the commodity element of the transmission services revenue.[26]

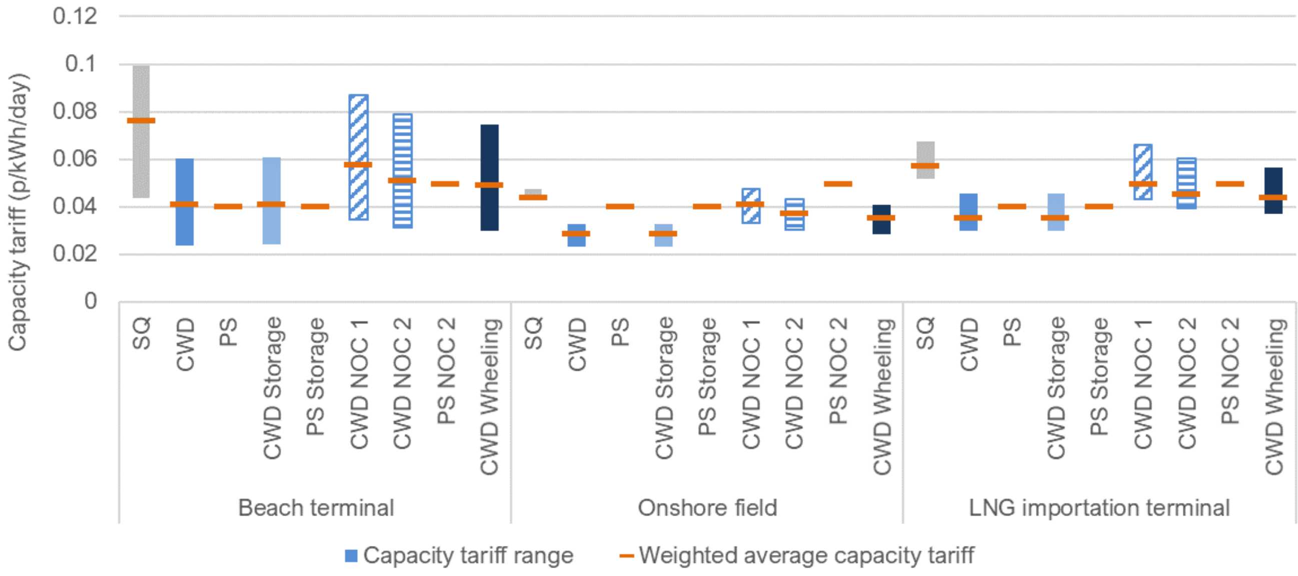
[23] We include bidirectional capability at BBL and include Moffat interconnector in this section for ease of comparison despite it currently only having physical flow capability in one direction.

[24] Our presentation of the standard annual tariff is less relevant for the modification options in which the only discount on the annual product is the interruptible product which is priced at a 10% discount. Our presentation bears more significance for the status quo in which daily and interruptible capacity products may incorporate a significant discount.

[25] Not including NOC tariffs which we consider separately.

[26] Given our assumption that bookings are equal to flows for all points other than GDNs, the capacity tariff represents a charge on each unit of gas flowed – i.e. it is effectively 'commoditised'. In effect, the charts compare the tariff paid to flow one kWh of gas making use of the annual capacity product both under the status quo and under the modification options.

Figure 3.3: Annual weighted average tariffs at entry points under each option (TD, 2030-31, £18/19)[27,28]



Comparison to the status quo

Considering the combined capacity and commodity tariff under the status quo, the weighted average annual tariff reduces relative to the status quo across all entry point types. The main reason for the decrease in the tariff relative is the significant commodity element of the charge which results from the fact that a substantial proportion of short-term capacity is currently booked at very low prices (often close to zero). This leads to greater revenue recovery which needs to be collected from the commodity tariff which is charged to flows irrespective of the capacity timeframe.

For each type of user, there can be a wide range of weighted average tariffs under both the status quo and the modification options. The tariff for entry points within this range depends on the capacity charge that is calculated for that point under the current LRMC methodology and under the relevant option. Considering the weighted average tariff, most network users would see a discount in their combined tariff. However, the range of tariffs under each option shows that a minority of entry points may see an increase.

Comparison of CWD and PS

The tariff impact of CWD relative to PS depends on the relative distance between entry and exit capacity. In general, we observe that the tariffs at beach terminals are slightly higher under CWD, reflecting their relative distance from exit capacity.[29] Given the high proportion of capacity bookings at beach terminals, the contribution towards revenue recovery means that the tariff is lower under the CWD at other entry points.

The PS approach assigns the same tariff to all entry points. There is therefore no tariff dispersion under this methodology. Dispersion of tariffs under the CWD depends on the relative differences in the volume of bookings and geographic location of entry points of that type. Where entry points are more variable in their volumes of bookings and more geographically dispersed (e.g. as is the case for beach terminals), this results in greater tariff dispersion.

[27] The labels shown for each option are consistent with those presented in Table 3.2. ‘CWD Storage’ and ‘PS Storage’ denote the CWD and PS RPM options with an 80% storage discount included.

[28] Note that for the status quo we have defined our own scenarios for future peak demand and supply (based on the two FES scenarios we are considering). We have then applied NGGT’s tariff model to calculate the tariff under the status quo based on the relevant scenario.

[29] E.g. St Fergus and Easington represent a large proportion of beach terminal flows

Impact of a NOC

Comparing the options which include some form of NOC to those which do not, we see that a NOC results in additional revenue recovery requirements to replace the loss of revenue resulting from the NOC discount. This raises the standard annual capacity tariffs at all points.

The tariff impact depends on the number of points that make use of the NOC under each option and on the magnitude of the discount they receive. The choice of NOC methodology impacts upon entry points differently depending on the volume of additional revenue recovery requirements that they introduce (see Section 3.2.5). We find that NOC Methodology 1 leads to the greatest increase in tariffs at entry points while the Wheeling methodology has the smallest impact.

Impact of 80% storage discount

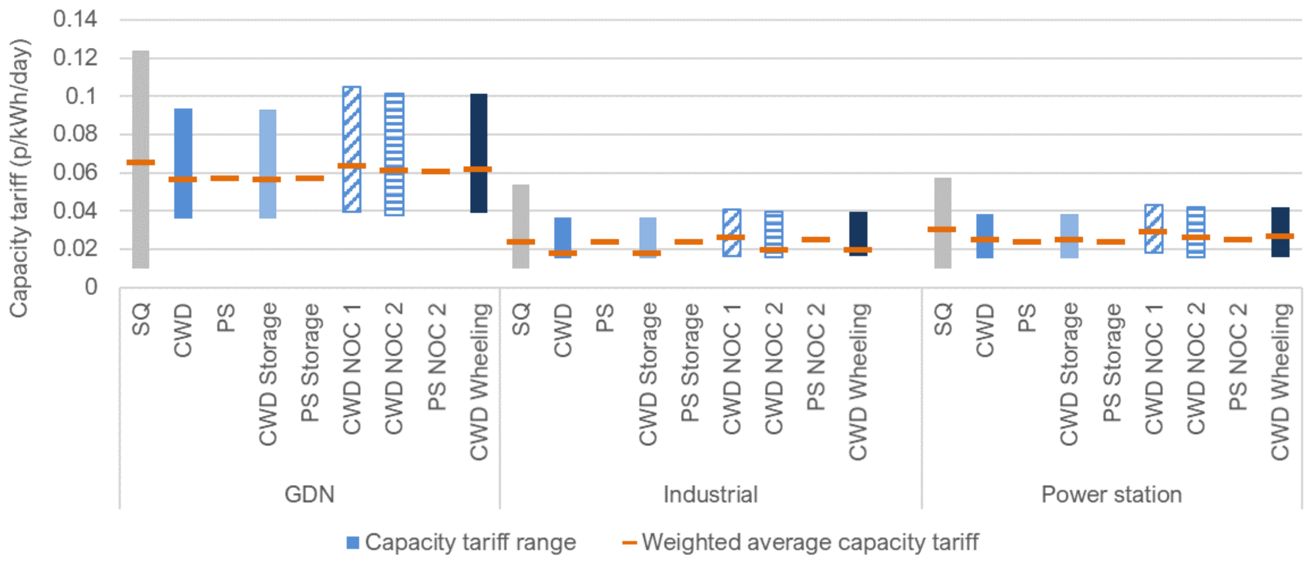
An 80% storage discount results in additional revenue recovery requirements which are spread to other entry points. In addition, all storage points are excluded from the revenue recovery charge under these options. In combination, this raises the entry tariff at non-storage points. However, even after accounting for both factors, the impact is limited given the relatively small amount of revenue recovered from gas storage under any of the options.

3.2.2. Impacts on annual tariffs at exit points

Average level of exit charges under each option

In Figure 3.4, we set out the dispersion of exit tariffs under each option and the average tariff, weighted by volume of capacity bookings. We include the commodity tariff within the status quo. As we do not set bookings equal to flows for GDN exit points, we commoditise the capacity element of the tariff.

Figure 3.4: Annual weighted average tariffs at exit points under each option (TD, 2030-31, £18/19)



Comparison to the status quo

At exit, the reduction in the standard annual capacity tariff relative to the status quo is much smaller than for entry. Recall that the reason for the significant reduction in the annual capacity tariff at entry was the fact that, under the status quo, there is a significant amount of capacity booking through shorter term products at a significant discount which leads to a higher commodity charge. The significant majority of capacity bookings at exit are at GDN exit points where the vast majority of capacity bookings are through the annual capacity product. Therefore, the impact on the commodity charge is smaller. Nevertheless, proportions of short-term bookings are higher at some other exit point types, meaning that a reduction in the tariff relative to the status quo is still observed.

After incorporating the TO commodity element within the status quo, we find that the weighted average annual tariff reduces relative to the status quo for GDNs and power stations. The tariff for industrial consumers under the status quo is comparable to those options which include a PS methodology but is generally higher than those based on CWD.

The LRMC methodology results in significant dispersion of tariffs across exit points indicated by the range of tariffs under the status quo. In locations where the LRMC methodology identifies a low estimated cost of expansion, the modification options can increase the tariff.

In comparing tariffs under the status quo and modification options, it is important to note that we present annual capacity tariffs. Many power stations and industrial consumers make use of the OCC which provides them with a discounted tariff relative to the annual product.

Comparison of CWD and PS

As was the case for entry points, we observe different impacts on exit points depending on the average distances from the exit point to gas entry capacity. NTS-connected I&C consumers have relatively low levels of capacity bookings relative to power stations and GDN exit points. NTS-connected I&C consumers would face a lower weighted average tariff under the CWD than PS options. CWD tariffs are, on average, slightly higher than PS for power stations and slightly lower for GDNs.

However, these results mask significant variation of transmission tariffs within any one type of exit point, demonstrated by the dispersion of tariffs when a CWD RPM is included. The relative impact on different GDN, industrial and power station exit points under CWD is dependent on the volume of capacity bookings and geographic location of that exit point.

Impact of a NOC

As for entry points, inclusion of a NOC increases weighted average exit tariffs. The impact depends on the volume of use of the NOC product under each methodology. When compared to the appropriate counterfactual (i.e. the CWD), NOC Methodology 1 results in the largest increase in tariffs while the Wheeling methodology has the smallest impact. The tariffs under NOC Methodology 2 are similar to that observed under the relevant RPM without a NOC (i.e. either PS or CWD).

Impact of 80% storage discount

Inclusion of an 80% storage discount, coupled with the exclusion of storage points from the revenue recovery charge, increases tariffs at other exit points. However, the impact is limited given the relatively small amount of revenue recovery from gas storage.

3.2.3. Impacts on GDN exit tariffs

GDNs book capacity to a 1-in-20 security standard, based on their interpretation of their licence. Given that we assume that other exit points will book capacity equal to flows, GDNs represent the only points that 'overbook' capacity within our model. Furthermore, tariffs at GDN exit points directly impact domestic gas consumers. Therefore, impacts on GDNs merit some further exploration.

Under the status quo arrangements, a proportion of the revenue requirement at exit is recovered from the commodity charge from shippers based on flows at the GDN exit points. Although GDNs to do not pay the commodity charge themselves, it is reasonable to assume that it is passed onto domestic gas consumers. Therefore, we consider the commodity and capacity charges at GDNs together.

How much GDN exit points contribute towards revenue recovery depends on several factors. The fact that GDNs are the only exit points to overbook capacity suggests that they may face an increase in tariffs, resulting from the move to a capacity-based charging structure.

On the other hand, a significant proportion of exit capacity is currently booked as daily and interruptible capacity, priced at significant discounts relative to the annual product,[30]. GDNs book most of their capacity through the

[30]A proportion of interruptible bookings is made at a zero price.

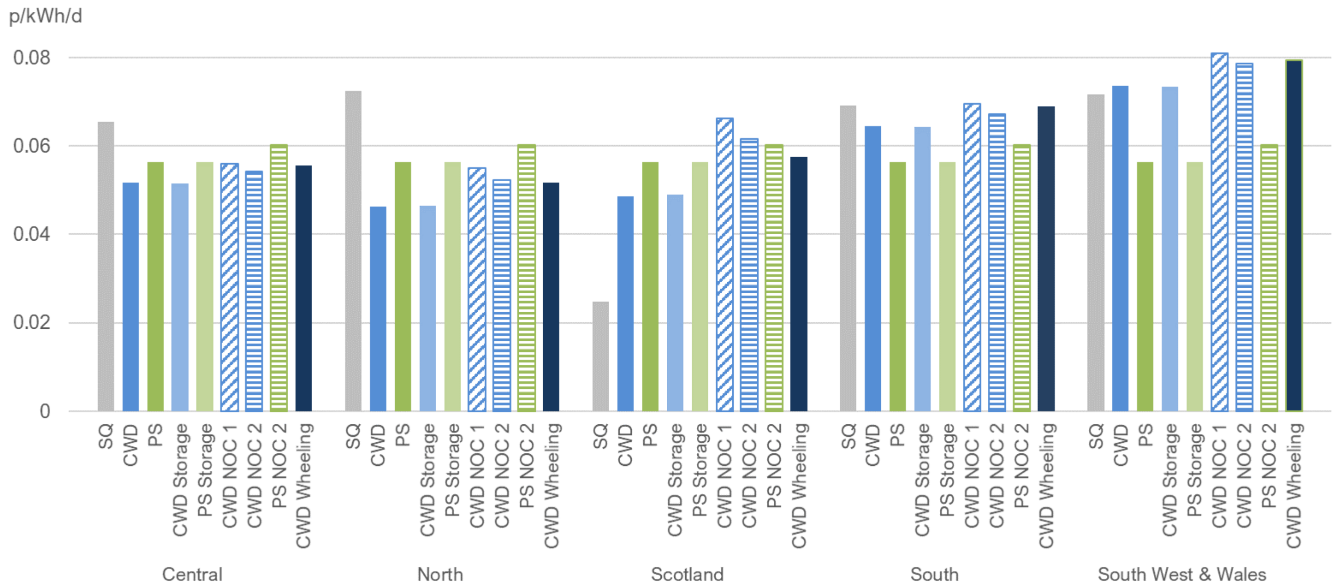
annual capacity product with no discount. Therefore, under the status quo, most of the revenue which is recovered through the capacity charge at exit is collected from GDNs.

Moving away from the status quo and to a capacity-based charging approach, exit points other than GDNs will no longer contribute to revenue recovery through the commodity charge. However, neither will they be able to avoid a proportion of the capacity charge by making use of heavily discounted shorter-term capacity products.[31] Removal of discounts on daily and interruptible products should itself decrease the share of revenue collected from GDNs. On balance, our modelling suggests that the combination of these impacts may result in a slight decrease in the tariff at GDN exit points such that the tariff options result in a lower tariff at GDN exit points.

Regional variation of GDN exit point tariffs

While PS options provide equal tariffs across all regions, where the CWD RPM is used, tariffs at GDN exit points will differ by exit point. We consider the regional variation in GDN exit tariffs in Figure 3.5. As previously, we include the TO commodity tariff within the status quo and commoditise the capacity element of the charge.[32]

Figure 3.5: Regional weighted average tariffs at GDN exit points under each option (TD, 2030-31, £18/19)



Comparison to the status quo

Relative to the status quo, the exit tariffs at some GDN exit points would increase, most notably in Scotland where the existing LRMC methodology results in a low exit tariff relative to the modification options. GDN exit tariffs in the North would reduce significantly under the modification options while in other regions exit tariffs would generally reduce or stay at a similar level to the status quo, with impacts dependent on the chosen modification option.

Comparison of CWD and PS

Comparing CWD and PS demonstrates that those regions that are, on average, relatively close to entry flows (Central and North regions) would face lower tariffs under a CWD methodology. Relative proximity to St Fergus means that the GDN exit tariff in Scotland is also lower when the CWD RPM is used, while those GDN exit points that are farther from system entry (South and South West and Wales) face the opposite effect.

[31] Under the proposed tariff options, the only discount available is on interruptible products, and this is small – at 10% of the reserve price of the annual product.

[32] Given that GDN bookings are assumed to be much higher than flows, 'commoditising' the capacity charge makes it appear larger. The ratio of GDN bookings to flows (in a given scenario and year) does not vary between tariff options, so this scaling up applies to all options equally.

Impact of a NOC

As observed for exit points more generally, a NOC tends to increase exit tariffs in all regions, as a result of the additional revenue recovery requirements. The increase in the tariff is greatest under NOC Methodology 1 and lowest under the Wheeling methodology.

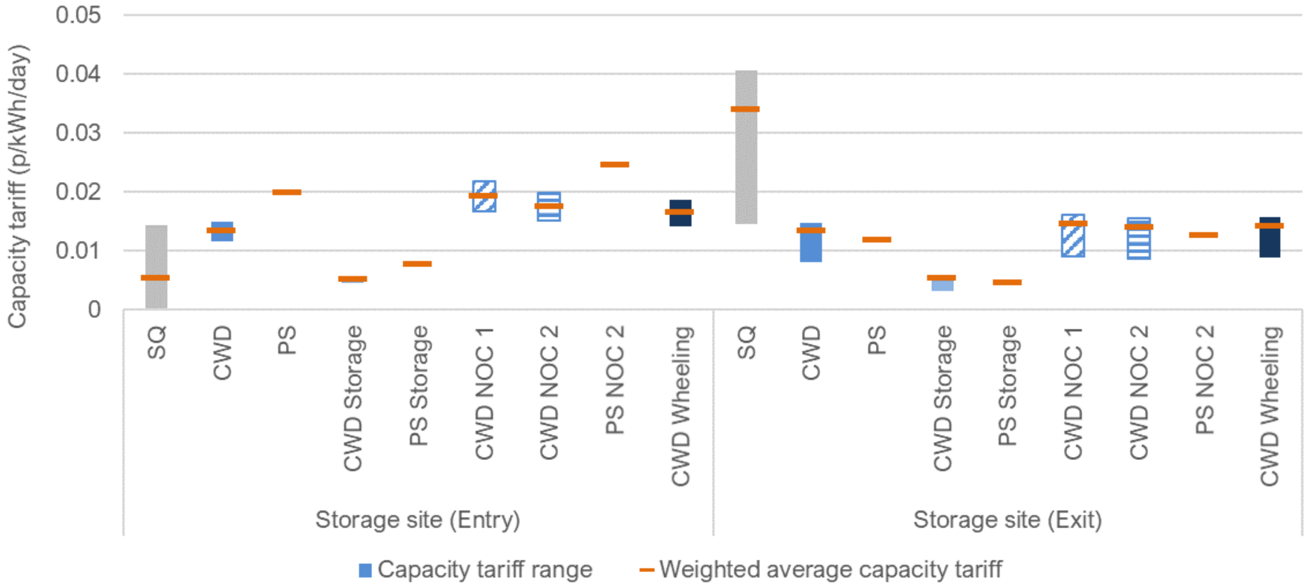
3.2.4. Impacts on annual tariffs at entry/exit points

We now consider the impacts of the modification options at combined entry and exit points. For simplicity we consider impacts on exit tariffs at Moffat, alongside tariffs for IUK and BBL.

Impacts on tariffs at storage points

In Figure 3.6, we consider the impacts of the options on the entry and exit capacity tariffs at gas storage points. Note that, under the status quo, the commodity tariff is not paid at storage entry or exit points.[33]

Figure 3.6: Annual weighted average tariffs at storage entry and exit points under each option (TD, 2030-31, £18/19)



Comparison to the status quo

We find that the weighted average storage entry tariff increases under all options relative to the status quo, while the exit tariff decreases.

We note that the annual capacity tariff may overestimate the capacity charge that is actually paid by storage, under the status quo, particularly at exit. Under existing arrangements, more than 70% of exit capacity at storage points was booked through the interruptible product in 2017/18. This capacity product is booked at a significant discount to the annual product. The effective tariff at storage exit points is therefore somewhat lower than the annual tariff represented in Figure 3.6.

[33] The commodity tariff is only levied on gas storage facility exit points for 'own use gas' which is a very small proportion of exit flows. We apply an exit commodity tariff of 0.06% to gas storage exit capacity which is consistent with this.

For tariffs at storage exit points, our results are also partly driven by modelling outcomes which suggest that there are no exit flows at several storage facilities within the gas year modelled.[34] At some of these storage exit points there is a low capacity tariff under the status quo. Therefore, we would observe a lower exit tariff in the case that we observed exit flows at these points.

Therefore, in terms of the actual price paid for bookings at storage exit points, we consider it likely that exit point tariffs would effectively increase on average relative to the status quo.

Comparison of CWD and PS

Given their relative distance from entry and exit capacity, storage entry points face higher capacity tariffs under the PS RPM. The opposite is true at storage exit points where the tariff is slightly higher under the CWD RPM.

Impacts of an 80% storage discount and the NOC

In combination with the revenue recovery exclusion for storage capacity bookings, those options which increase the storage discount from 50% to 80% unsurprisingly reduce the tariffs at storage entry and exit.

As for other entry and exit points, the inclusion of a NOC increases the weighted average tariff at both storage entry and exit. However, unlike at many other entry and exit points, storage cannot make use of the NOC, and so would not benefit from a discounted tariff.

Impacts on tariffs at interconnection points

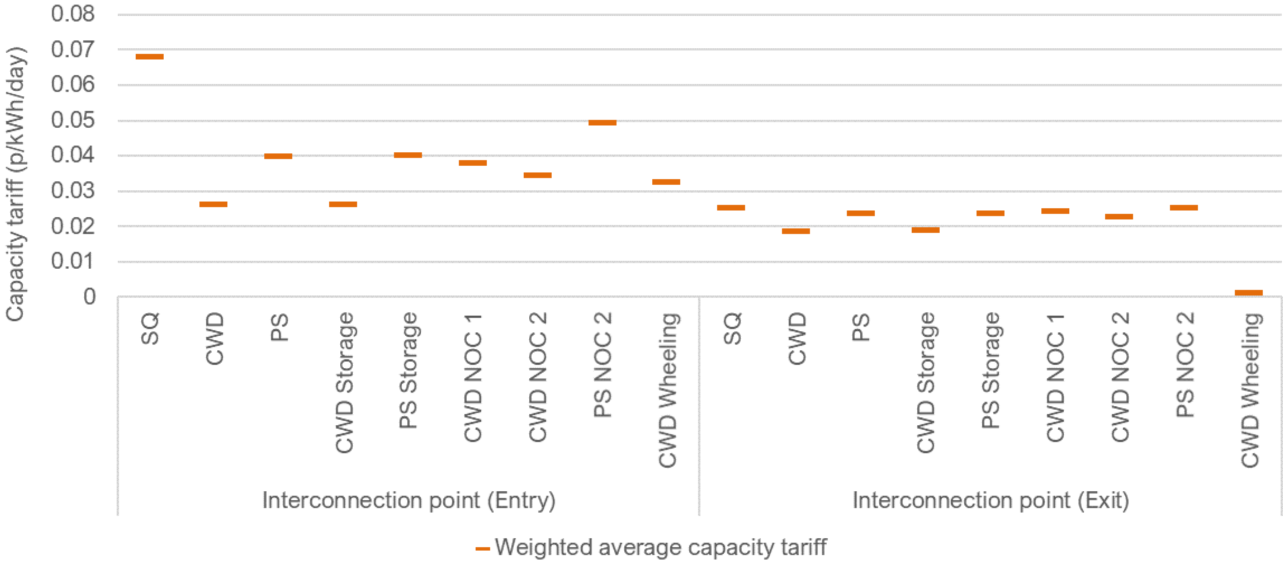
In Figure 3.7, we present annual capacity tariffs at interconnector entry and exit points. Our modelling includes bidirectional flow capability at BBL. Therefore, weighted average entry tariffs reflect both IUK and BBL flows entering the NTS at Bacton. The weighted average exit tariffs reflect capacity bookings made at Bacton and Moffat. As previously, we combine the TO commodity charge and the capacity tariff under the status quo.

[34] The lack of flows observed at some storage exit points results from a combination of the following:

1. The modelling includes seasonal price spreads which drive injection and withdrawal behaviour of medium-range storage sites but does not reflect price volatility that would drive the economics of short-range (daily/intraday) storage operations observed in reality (as it is not a stochastic market model).
2. The model is run over a two-year period and incorporates perfect foresight, optimising at daily granularity.

As a result of the first assumption, the wholesale gas price shows a steady profile over the course of the year, reducing the potential for short term (within day or daily) arbitrage. Based on the second assumption, some storage facilities can optimise revenues by taking a "long-term" view and hence could withdraw gas in anticipation of higher prices over the modelled gas year. In combination, this may lead to underestimates of the response of assets to daily and within day volatility in gas supply and demand dynamics. We observe a particular effect on short-range storage facilities who only withdraw gas from store (entry flows only) in the modelled gas year while most long-range (inter-seasonal) storage sites do have some level of entry and exit flows.

Figure 3.7: Annual weighted average tariffs at interconnector entry and exit points under each option (TD, 2030-31, £18/19)



After including the TO commodity tariff, we observe a decrease in the tariff at interconnection entry points with the relative decrease driven by the commodity charge at entry and exit under the status quo. As the interconnection entry points to GB connect to the gas network at only Bacton, there is no tariff dispersion for interconnector entry under any option.

Under the TD scenario, in our modelling there are no exit flows to the continent in 2030-31.[35] The weighted average tariff at exit is therefore solely driven by exit flows over the Moffat interconnector. Nevertheless, the capacity tariffs at Moffat and Bacton are similar, so the tariff dispersion (in the case that there were exit flows to the continent) would be small.

There is a small decrease in the tariff at Moffat relative to the status quo, with a more significant decrease under those options in which a CWD RPM is used.

Comparison of CWD and PS

The CWD RPM results in lower tariffs at the Bacton entry point in comparison to the PS, while exit tariffs at Moffat are also lower, driven by the relative proximity to St Fergus and Teesside.

Impacts of the Ireland Security Discount

The significantly lower exit tariff observed under the CWD Wheeling option results from the 95% Ireland Security Discount applied to the Moffat exit point.

3.2.5. Impacts of a NOC

For those options which include a NOC, we have compared the NOC tariff to the standard capacity tariff to determine the extent to which each entry-exit route combination would make use of the NOC.[36] Where the NOC tariff is lower than the standard capacity tariff, and where there are no capacity constraints, we assume that the relevant entry-exit route combination would choose to use the NOC product. In this section, we estimate the take-up of the NOC product, and demonstrate the resulting impacts on revenue recovery.

[35] This results from the fact that gas prices on the continent are lower than in GB in this gas year and scenario. Additionally, our gas market model is deterministic, and optimises at daily granularity, assuming perfect foresight. This may underestimate the role of assets who respond to short-term volatility in gas prices (including interconnectors).

[36] Our analysis also incorporates capacity constraints which may restrict use of the NOC product. Entry-exit route combinations may use the NOC product for a proportion of their flows while paying the standard capacity tariff for the remainder.

The Wheeling methodology restricts use of the NOC to points which are separated by a distance of zero kilometres.[37, 38, 39] Therefore, for this analysis we restricted eligibility under the Wheeling methodology accordingly.

NOC methodologies 1 and 2 do not include any eligibility restrictions. Hence, in theory all routes are able to make use of the NOC products available. However, in order to place a necessary limit on the routes modelled, we have only included the NOC for those routes where the entry-exit route combination has used the OCC in the gas year 2017-18.

Take-up of the NOC product

Table 3.1 summarises the extent of take-up of the NOC product under each option:

Table 3.1: Take-up of the NOC (TD, 2030-31)

RPM	Eligible routes (according to NOC method)	Modelled routes	Number of routes that use shorthaul	Total volume of shorthaul flows (TWh/year)	Percentage of modelled flows using shorthaul	Longest distance with use of shorthaul (km)	Simple average route distance (km)
Status quo	All routes	48	35	167.4	45%	274.0[40]	67.1
CWD, Method 1	All routes	48	30	138.2	37%	164.5	37.6
CWD, Method 2	All routes	48	14	52.2	14%	24.0	5.8
PS, Method 2	All routes	48	18	72.1	20%	27.2	10.2
CWD Wheeling	All routes with a distance of 0 km.	9	6	22.2	56%[41]	1.2	0.3

In our modelling, all options would result in a lower take-up than under the status quo. Of the modification options, CWD Methodology 1 has the highest take-up. The number of routes that make use of the NOC product remains relatively high (32), compared to the status quo, although the total volume of NOC flows falls. A maximum route distance of 164.5 km continues to use the NOC for a proportion of flows which is lower than the route distance which made use of the OCC in 2017/18 (274 km).

CWD Methodology 2 results in a more significant reduction in the take-up of the NOC. There is a slightly higher uptake of the NOC Methodology 2 under the PS RPM than under CWD. This is driven by the higher standard NTS capacity tariff for I&Cs under the PS compared to CWD (see Figure 3.4). As we would expect given the reduced eligibility of the product, take-up is significantly lower under the Wheeling option.

[37] The UNC0678I modification report includes the following definition of the Wheeling methodology: "A Transmission Services charge allowing the transportation of gas from one Entry Point to an Exit Point across 0 km distance as defined in Annex A of the FCC Methodology statement."

[38] Storage entry and exit points and GDN exit points are not eligible to use the NOC under any design.

[39] While the Wheeling charge is restricted to entry and exit points separated by a 0km distance, the methodology used to calculate this distance can differ slightly from the pipeline distances registered by NGGT within its pipeline book. Therefore, it is possible for the registered physical distance to be slightly greater than 0km.

[40] This represents the largest distance of route that NGGT identify made use of the OCC under existing arrangements in the gas year 2017-18. The modelling suggests that routes of an even greater distance may have commercial benefits in making use of the OCC product. See: National Grid, April 2019, Optional Charge Analysis.

[41] This represents the percentage of the nine modelled routes rather than the 48 that are modelled under other NOC options. In comparison to the full 48 routes, the percentage of modelled flows that use shorthaul would be 6%.

Impacts on revenue recovery

Considering the volume of flows that use the NOC product, we can estimate the revenue that is 'lost' by comparing the revenue that would have been recovered under the standard tariff with that recovered from the NOC. This corresponds to the amount of 'cross-subsidisation' by non-shorthaul users – i.e. the additional revenue that needs to be recovered from non-shorthaul users as a result of the shorthaul discount.

We also calculate the average amount of revenue that would be recovered under each option per unit of NOC flow; a NOC 'shadow tariff'. We present the impacts on revenue recovery in Table 3.2:

Table 3.2: Revenue recovered and lost from use of the NOC (TD, 2030-31)

Tariff option	Total volume of shorthaul flows (TWh/year)	Amount of revenue from NOC (£18/19m)	Average 'shadow' tariff i.e. revenue recovered per unit of flow (p/kWh) (£18/19)	Lost revenue that would otherwise be recovered from NOC users who paid the standard tariff (£18/19m)[42]
Status quo	167.4	55.2[43]	0.0330	89.6
CWD, Method 1	138.2	26.4	0.0191	94.9
CWD, Method 2	52.2	18.0	0.0344	38.4
PS, Method 2	72.1	32.2	0.0447	52.0
CWD Wheeling	22.2	7.2	0.0323	16.7

Lost revenue results from a combination of the amount of flows that make use of the NOC product and the size of the discount available to NOC users. Any lost revenue would be spread across entry and exit users through the revenue recovery charge.

Given the greater use of the NOC under CWD Methodology 1, lost revenue is comparable to that seen under the status quo. Eligibility restrictions under the Wheeling charge option mean that the total lost revenue is relatively low.

The 'shadow tariff' results suggest that for those who use the NOC, CWD Methodology 1 is potentially more generous than the OCC. We observe the highest average revenue contribution under the PS Methodology 2 option. Revenue contributions are similar under the CWD Methodology 2 option, the status quo and Wheeling methodology. Revenue recovery per unit of flow is lowest under NOC Methodology 1.

[42] Note that this does not account for the potential for any network user decisions to bypass the NTS.

[43] Note that under the status quo, this figure includes both capacity and OCC revenue from users that take up the OCC. This has no impact on the lost revenue, which continued to represent what would have been recovered if OCC users were liable for the standard entry and exit commodity tariffs.

3.3. WIDER SYSTEM ANALYSIS

3.3.1. Impacts on consumers

In this section, we explore the impacts of the options on consumers. We present total consumer welfare and use our consumer stratification (Section 3.1.2.) to consider the estimated bill impacts on different types of consumers.

Ofgem's appraisal of the options focusses on the impacts of tariff reform on gas consumers. Gas consumer welfare impacts arise from two mechanisms:

1. The direct impact of **tariff** increases or decreases: Where tariff changes affect suppliers, we assume that these tariff changes are passed onto consumers. For example, we assume that the tariff at GDN exit points is passed on in full.
2. The **wholesale gas price**: The change to tariffs may impact on the marginal unit of gas which may in turn affect the wholesale gas price. We assume that any changes to the wholesale price will be passed onto consumers.

In addition to gas consumers, impacts of tariff reform may have knock on impacts on the **wholesale electricity price**. Changes to the price paid for gas, including the transmission tariff, will affect the cost of the gas consumed by gas-fired power stations. Where these generators represent the marginal unit of electricity, we assume that they will affect the wholesale electricity price, which is then passed onto consumers. We present impacts on electricity consumers in Section 3.4.4.

The mechanisms that drive consumer welfare impacts are nuanced and dependent upon certain outcomes within the gas and electricity markets, such as the supply merit order.

In our analysis, we assumed that shippers (except at GDN exit points) only book as much capacity as they need (i.e. they profile capacity bookings to meet flow requirements), and transmission tariffs are treated as part of the marginal cost of supply. Therefore, tariff options impact on the market price when the marginal cost of the marginal unit of supply is affected by a change to the transmission tariff. Under those options in which costs of the marginal unit of gas reduce as a result of a lower tariff, the wholesale price will decrease, hence improving consumer welfare.

Alternatively, it is possible that changes in tariffs affect the merit order itself. For example, a decrease in the tariff of a unit that was previously outside of the merit order may allow it to come into merit. Similarly, a marginal unit may be pushed out of merit by an increase in its tariff. Any changes in the merit order may increase or decrease the wholesale price, depending on the magnitude of changes in the tariffs of the relevant units. Given the magnitude of changes to tariffs (of the order of £0.1/MWh) in comparison to other variables which impact on input prices (e.g. a global gas price of approximately £22/MWh in 2030-31 in our TD scenario), the change in the tariff may not be expected to impact on the merit order in a significant number of periods of the year.

Finally, it is important to note that even a small change in the wholesale gas price would impact on a large volume of gas consumption and can therefore result in large impacts on consumer welfare in the aggregate. For example, under the TD scenario in 2030-31, annual gas consumption is approximately 750 TWh per year[44]. Therefore, even a small change in the gas market price of £0.1/MWh would result in a total annual benefit to gas consumers of £75 million.

In summary, consumer welfare impacts are likely to be sensitive to the effects on the marginal unit of gas supply, both in theory and in practice. While our modelling provides estimates of consumer welfare based on FES scenario supply and demand assumptions, market outcomes which differ from these scenarios could, in turn, affect the magnitude of the consumer welfare and bill impacts.

[44] Note that while gas demand from domestic and I&C consumers is fixed, gas-fired power station demand is determined endogenously based on gas and electricity market fundamentals. The FES scenario is used to define the minimum and maximum range of this demand.

The merit order and impacts on the wholesale price

Each of the modification options has different impacts on the tariffs at various entry and exit points. For example, as shown in Section 3.2, the PS and CWD RPMs impact on tariffs differently depending on the relative distance from entry to exit capacity. Additionally, many I&C, power stations and interconnector consumers make use of the OCC under the status quo and our analysis suggests that many would continue to use a NOC if available.

Given that the marginal unit of gas and electricity may be assumed to set the wholesale gas and electricity price, the change in the market price will depend upon whether the tariff option increases or reduces the tariff of the marginal unit on average over the course of the year. The tariff option may increase the tariff of a number of inframarginal units but would still reduce the market price where the aggregate effect is to reduce the tariff of the marginal unit.

Figure 3.8 and Figure 3.9 provide a simplified representation of this effect. The figures demonstrate the mechanism for impacts on the wholesale market price – i.e. the tariff change at the marginal unit of supply. As gas-fired power generators will often represent the marginal unit of electricity, this mechanism applies equally to the gas and the electricity price.

Changes to the gas and electricity market prices will, in turn, be one of the main mechanisms for consumer welfare impacts. It is therefore important to bear in mind the sensitivity of these impacts to the type of entry point which represents the marginal unit of gas and the power station that represents the marginal unit of electricity, based on the supply and demand fundamentals. Our results which show the wholesale gas price and the consumer welfare impacts under the SP sensitivity (Section 6) demonstrate the potential impacts of changes to global gas prices and domestic demand for example. As tariff changes affect different units of supply in different ways (e.g. depending on location, capacity, and access to any discounts), we note that the sensitivity of welfare to the marginal unit of supply is both a feature of our modelling and of reality.

Figure 3.8: Illustrative example of market price under status quo

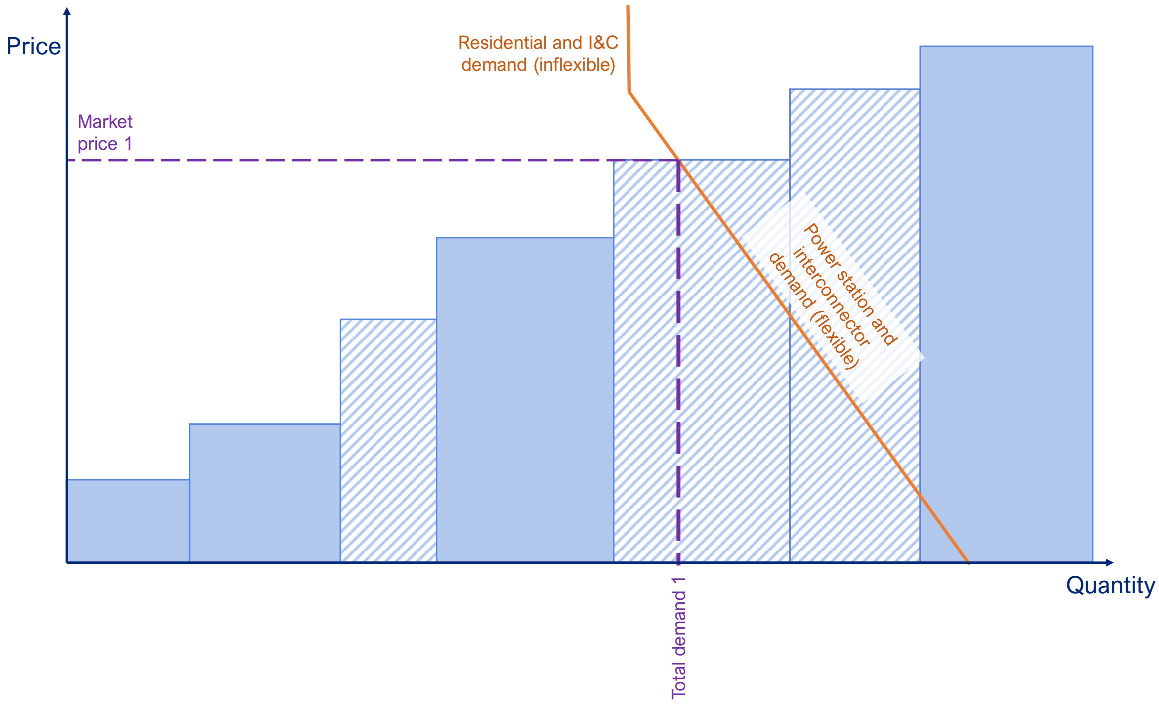
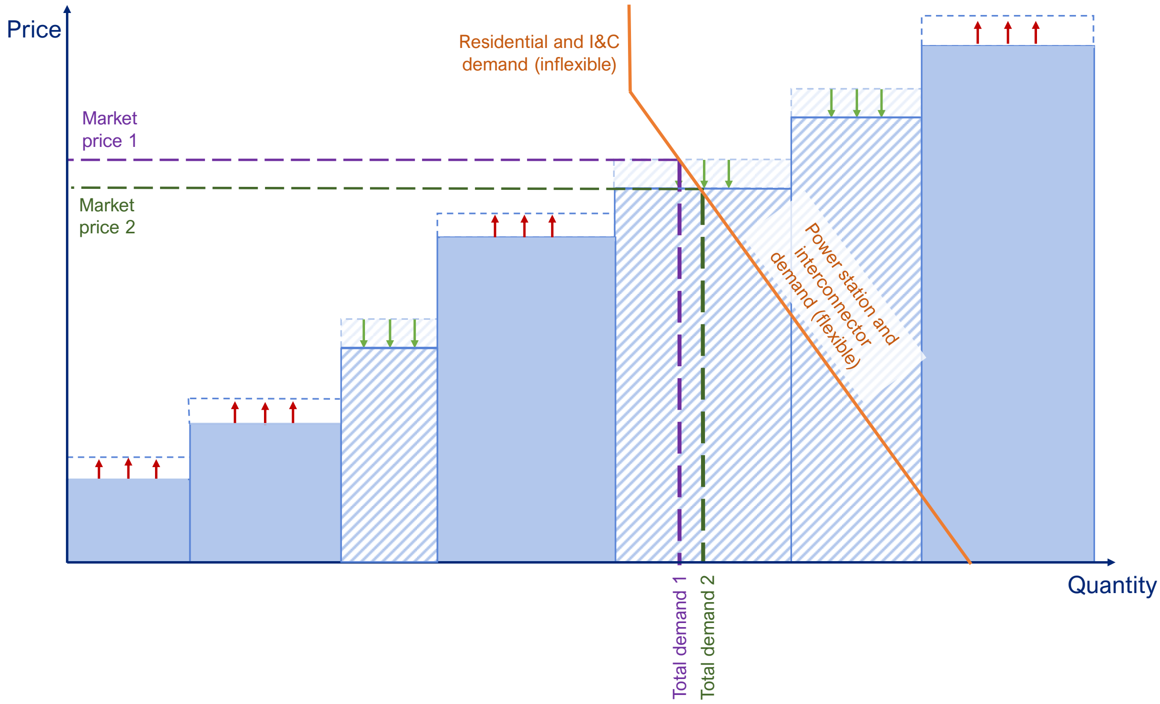


Figure 3.9: Illustrative example of market price under modification option



3.3.2. Impacts on the wholesale gas price

In this section, we consider the impacts of changes to the tariffs on the wholesale market price through the mechanism of the change to the tariff at marginal supply units.

We show the estimated impacts of each option on the gas wholesale market price in Figure 3.10 below.

Figure 3.10: Simulated wholesale gas market price impacts under each option (TD, 2030-31, £18/19)[45]

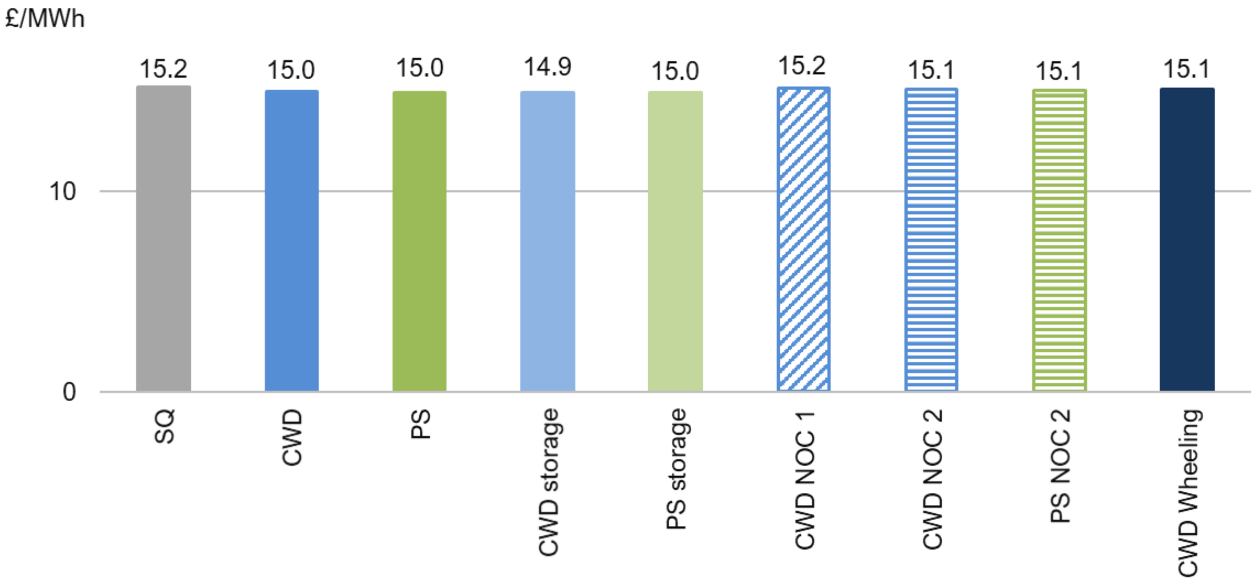


Figure 3.10 shows that the tariff methodology only has a small impact on the wholesale gas price under any option, as would be expected. We find a decrease in the wholesale gas price under all options (and in all modelled years). This suggests that the reduction in the annual capacity tariff at entry points (see Figure 3.3) leads to a reduction in the costs of the marginal unit of gas on average and hence to a reduction in the wholesale gas price. While changes

[45] We conducted a t-test on the price series of each gas year under each option in comparison with the status quo. Under this test, the differences in the gas price were significant at the 95% confidence level.

to the tariffs will affect different entry points differently, this implies that the removal of the effective cross-subsidy from long-term to short-term capacity products (which are often priced at significant discounts) reduces the tariff of the marginal setting entry source on average over the course of the year.

Other things equal, the gas price is slightly higher when a NOC is present. Again, while some entry sources may benefit from the NOC discount in some periods, this suggests that the average effect at the margin is to increase the cost of gas supply as a result of the additional revenue recovery requirements to account for the NOC discount. CWD NOC Methodology 1 results in the highest gas price (other than the status quo), which may partly be attributed to the more extensive revenue recovery requirements that it introduces (see Section 3.2.5).

In the case of the CWD RPM, the gas price is slightly lower where an 80% storage discount is included[46]. For those periods of the year in which storage acts as the marginal unit of supply, it will often do so at a discounted tariff of the order of £0.1/MWh (see Figure 3.6)[47] under the 80% discount option, in turn reducing the wholesale gas price.

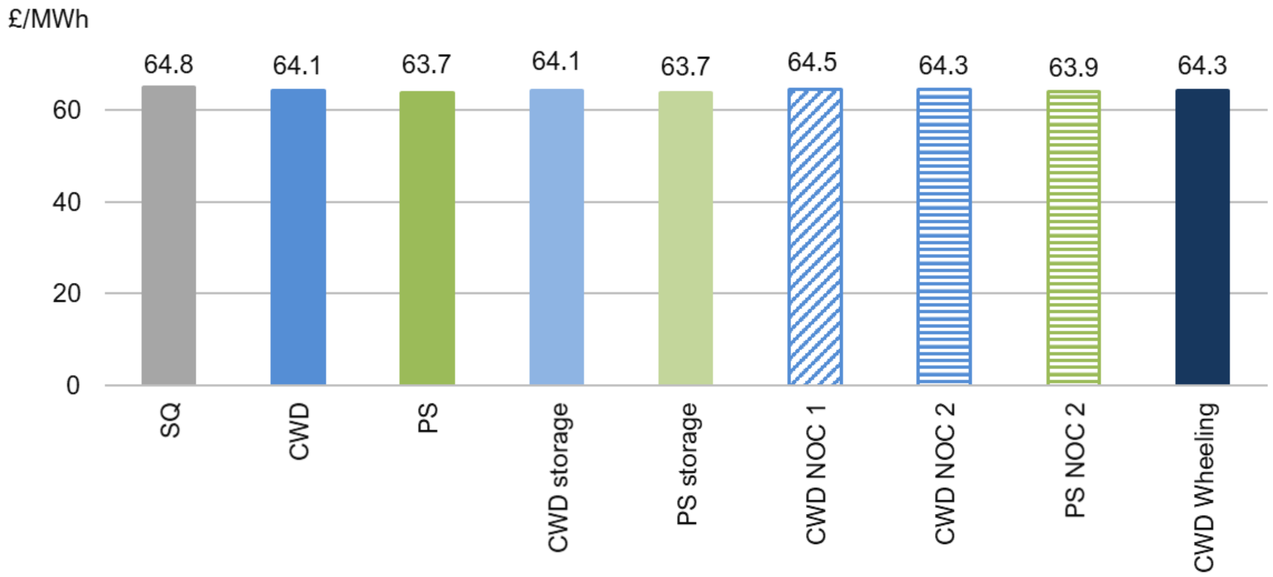
3.3.3. Impacts on the wholesale electricity price

Gas-fired power stations represent an important part of the electricity mix. From Q1 2018 to Q1 2019, between 28% and 36% of electricity in Great Britain was generated each quarter by gas-fired power stations.[48] These power stations are often, but not always, the marginal units. Therefore, they can affect the wholesale electricity price. Therefore, a combination of the effects of the tariff methodology on the wholesale gas price and on the tariff paid by electricity generators can have consequential impacts on the electricity market.

By combining the gas and electricity market models, we were able to consider the potential impacts on the electricity market resulting from changes to gas tariffs.

Figure 3.11 shows the estimated impact of the options on the electricity market price under the TD scenario in gas year 2030/31:

Figure 3.11: Simulated wholesale electricity prices by option (TD, 2030-31, £18/19)[49]



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[46] The difference in the gas price between the CWD and CWD Storage options is £0.0407/MWh.

[47] The majority of storage entry capacity is booked using the annual capacity product (around 85% in 2017/18).

[48] See: Ofgem, October 2019, Electricity generation mix by quarter and fuel source (GB).

[49] We conducted a t-test on the price series of each gas year under each option in comparison with the status quo. Under this test, the differences in the gas price were significant at the 95% confidence level.

We find that all options result in a lower electricity price relative to the status quo (again in both the TD scenario and SP sensitivity, and in all modelled years). We also find that the reduction in electricity price is larger for those options which include a PS rather than a CWD methodology. This reflects the lower exit tariffs at power stations, as shown in Figure 3.4. Under the PS and PS Storage options, the electricity price is just over £1/MWh lower than in the status quo.

Comparing the NOC and non-NOC versions of the options, we see a slightly higher average electricity price when a NOC is included. This suggests that, on average, over the course of the year, the slightly higher wholesale gas price (compared to the non-NOC options) outweighs the benefits of any NOC discount for the electricity generators. NOC Methodology 1 results in the highest electricity price.

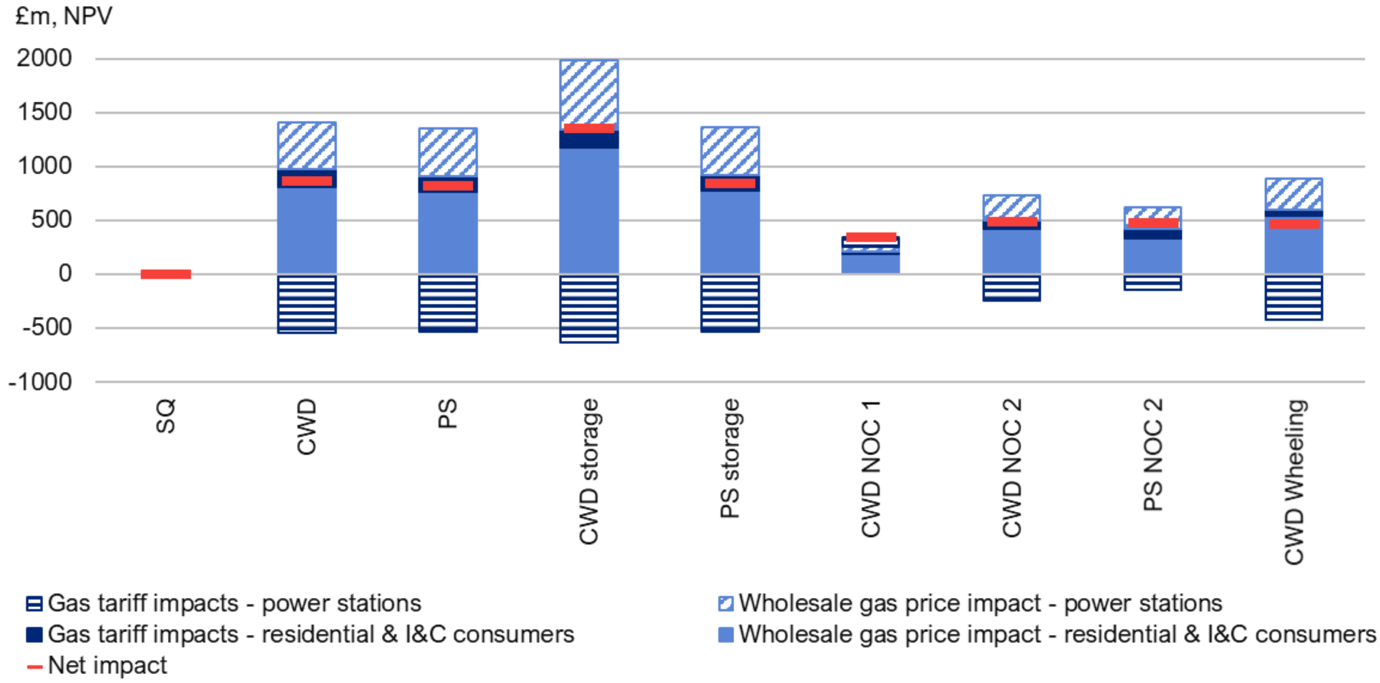
3.3.4. Consumer welfare

The consumer welfare change from the status quo is driven by a combination of changes in the gas market price, the transmission tariff (discussed in Section 3.2.2) which is passed onto consumers, and the change to the electricity market price.

Gas market consumer welfare impacts

In assessing the options, Ofgem will consider the relative impacts on gas market consumer welfare. In Figure 3.12, we present the NPV of the gas market consumer welfare impact between the years 2022 and 2031 under each option. This includes the impact on all consumers of gas including residential, I&C customers and gas-fired power generators.

Figure 3.12: Gas consumer welfare impacts by option (TD, 2022-2031, NPV, discounted to £18/19)



Our consumer welfare results reflect the combination of impacts discussed previously. While the effects of tariff reform on gas prices are small, given that they impact on a large number of consumers, the consumer welfare impacts are more significant. In fact, the magnitude of the impact resulting directly from any change to the tariff itself is significantly outweighed by consequential impacts on the gas market prices.

For gas-fired power generators, gas tariff reform has two opposing effects. On the one hand, the reduction in the wholesale gas price reduces their input costs. On the other hand, most of the options (other than NOC Methodology 1) increase their exit tariff relative to the status quo. More generally, the impact on their exit tariff is reduced where a NOC is present. Gas-fired power generators are also impacted by knock-on effects of gas tariff reform on the wholesale electricity market price. Where the electricity price decreases, power stations will earn less revenue from the electricity market per unit of power generated and vice versa. We present these impacts in Figure 3.13 along with electricity consumer welfare impacts. We discuss the full impact of gas tariff reform on power stations in Section 3.4.5.[50]

Under the TD scenario, all options result in a positive gas market consumer welfare impact relative to the status quo. Consumer welfare is slightly higher under the CWD options than for PS and is highest under the option which includes the 80% storage discount alongside a CWD RPM. As mentioned previously, including an 80% storage discount within the CWD methodology reduces the wholesale gas price slightly, resulting in additional consumer benefit.[51] This option results in a total NPV consumer benefit of close to £1.5 billion over the full period.

The increase in gas market consumer welfare is lower when a NOC is included within the arrangements. While still positive, our modelling suggests that the NOC dampens the reduction in the wholesale gas price. NOC Methodology 1 results in the lowest consumer welfare benefit. The largest consumer welfare under a NOC option is for the CWD RPM with NOC Methodology 2 driven by the reduction in the wholesale gas price.

Electricity market consumer and power station welfare impacts

In Figure 3.13, we present the NPV of the electricity market consumer welfare impact between the years 2022 and 2031 under each option. This includes the impact on all electricity consumers of including domestic and I&C customers. While not electricity consumers, we also present electricity market revenue impacts for gas-fired power generators in this figure in order to allow for direct comparability with Figure 3.12 above.[52]

These electricity market welfare impacts result from the change to the electricity price shown in Figure 3.11. As discussed, this reflects a combination of the change to the wholesale gas price and of the particular tariff impacts on gas-fired power stations under each option. As noted in Section 2.1.2, some generators may try to recover lost revenues resulting from a decrease in the electricity wholesale price through the capacity market which do not include within the model. We therefore consider that these results may represent an over-estimate of electricity consumer benefits. The extent of the over-estimate would be dependent on the extent of competition in the capacity market.

[50] We note that power station impacts also reflect changes in the amount of electricity they generate, and hence their operational and carbon costs, as well as gas demand. As illustrated in Figure 3.8 and Figure 3.9, power station gas demand is flexible, and captures the interaction between the gas and electricity markets. All else equal, a lower gas price will lead to an increase in gas-fired power generation and a corresponding increase in power station demand. All else equal, a higher electricity price would have the same effect.

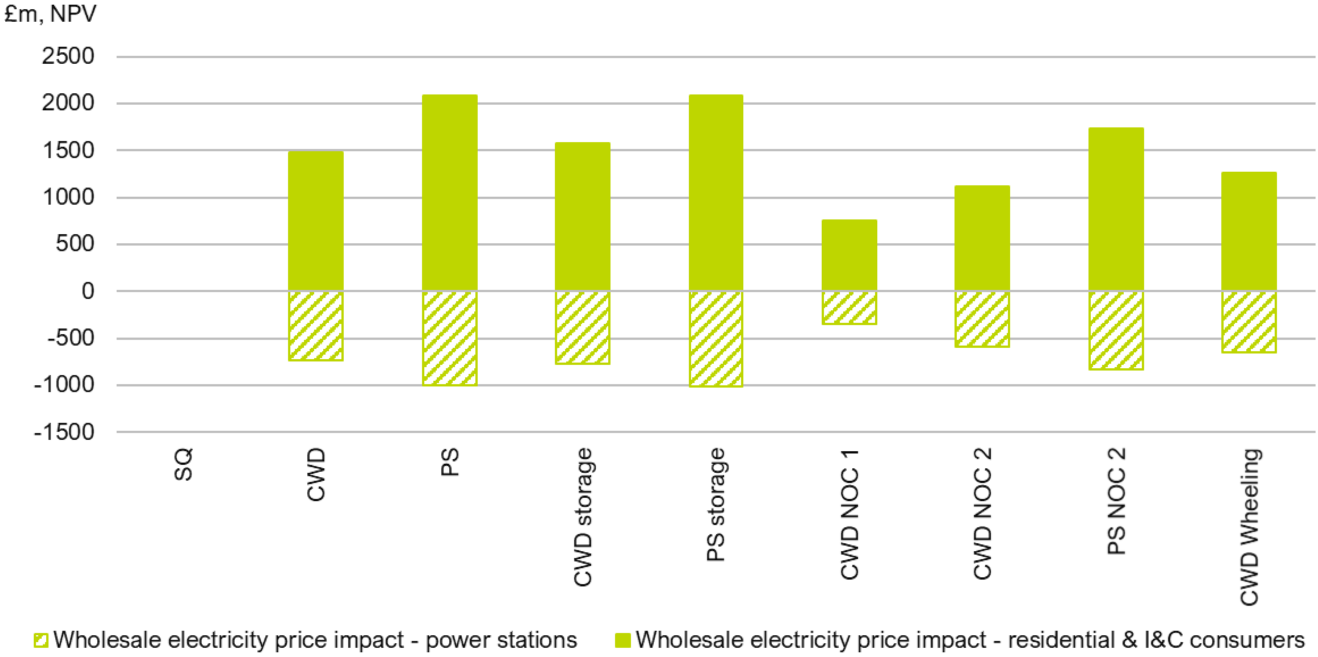
In contrast, domestic consumer gas (and electricity) demand is assumed to be inflexible. Non-domestic gas (and electricity) demand is also assumed to be largely inflexible, with the exception of some limited demand-side response when the price of gas goes higher than the price of diesel. We do not observe any such demand side response in our modelling.

[51] We note that this effect is more pronounced in our earlier modelled years (2022 and 2026). This is driven by the presence of existing contracts for some entry points, combined with our assumption that these would be utilised first before any additional capacity bookings.

In our modelling, we find that under the CWD Storage option, existing contracts at LNG terminals are sufficient to meet the entry capacity needs of those points in 2022 and 2026. This means that capacity tariff costs at LNG terminal entry points are minimal (solely reflecting the revenue recovery element – see Table 2.2). These points represent the marginal gas unit in a sizeable proportion of the year, driving the wholesale price down.

[52] We discuss the full impact of gas tariff reform on power stations in Section 3.4.5. As mentioned previously, power station impacts also reflect changes in the amount of electricity generated.

Figure 3.13: Electricity market welfare impacts by option (TD, 2022-2031, NPV, discounted to £18/19)



Under the TD scenario, all options result in a positive electricity market consumer welfare impact relative to the status quo. Consumer welfare is higher under the PS options than for CWD. This reflects the lower electricity price (driven by lower exit tariffs at power stations), presented in Figure 3.11. Consumer welfare is highest under the PS and PS Storage options, resulting in a total NPV consumer benefit of just over to £2 billion over the full period.

The increase in electricity market consumer welfare is lower when a NOC is included within the arrangements. This is as a result of the more modest reduction in the wholesale electricity price (see Figure 3.11). NOC Methodology 1 results in the lowest electricity consumer welfare. The largest consumer welfare under a NOC option is for the PS RPM with NOC Methodology 2 driven by the reduction in the wholesale electricity price. The electricity consumer surplus under this option is comparable with the non-NOC options.

Conversely, under the TD scenario, all options result in a negative electricity market revenue impact on power stations, relative to the status quo. Power station impact is lower under the PS options than for CWD, again as a result of the lower electricity price. Similarly, the reduction in power station electricity market revenue is smaller when a NOC is included within the arrangements.

It is interesting to note that under the TD scenario, the reduction in power station electricity market revenue does not outweigh the positive electricity consumer welfare impacts. It is important to note that this chart does not include the electricity market revenue impacts for generators other than gas-fired generation.

3.4. Bill Impacts and revenue impacts for gas-fired power stations

Next, we break down the total bill impacts by consumer type, considering domestic and I&C consumers. We firstly consider the impacts on gas consumers, combining the impacts of the change in the gas market price and any change to the tariff at the GDN exit point. We consider the impacts on the revenues of gas-fired power stations in Section 3.4.4.

3.4.1. Domestic gas consumer bill impacts

Domestic bill impacts are estimated according to household consumption levels, using the median, lower quartile and upper quartile gas and electricity consumption values from the BEIS NEED dataset (2017).[53] The consumption values used are presented in Section 2.1.3. Annual bill impacts on median, lower quartile and upper quartile consumption domestic consumers are presented on Figure 3.14, Figure 3.15 and Figure 3.16 respectively.

Figure 3.14: Estimated gas bill impact for median consumption domestic gas consumers (TD, 2030-31, £18/19)

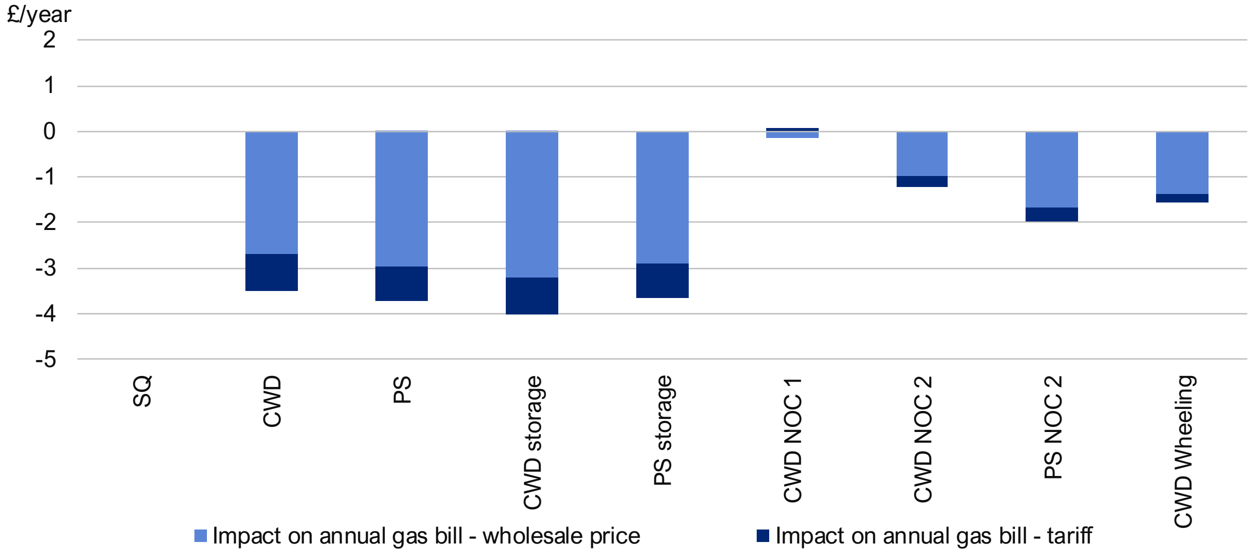
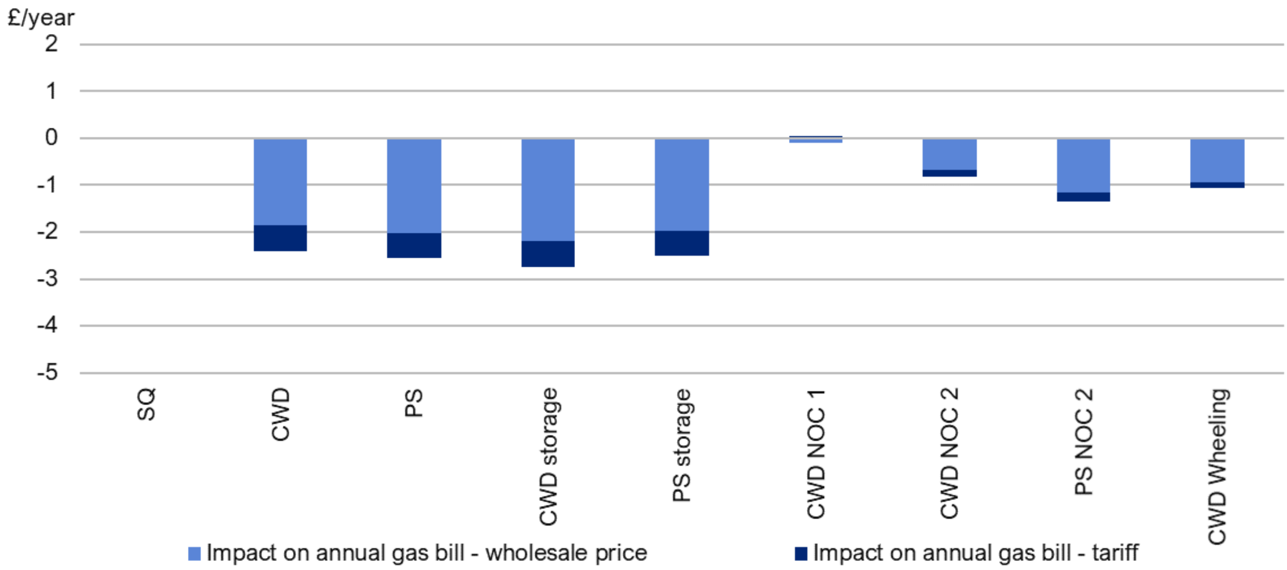
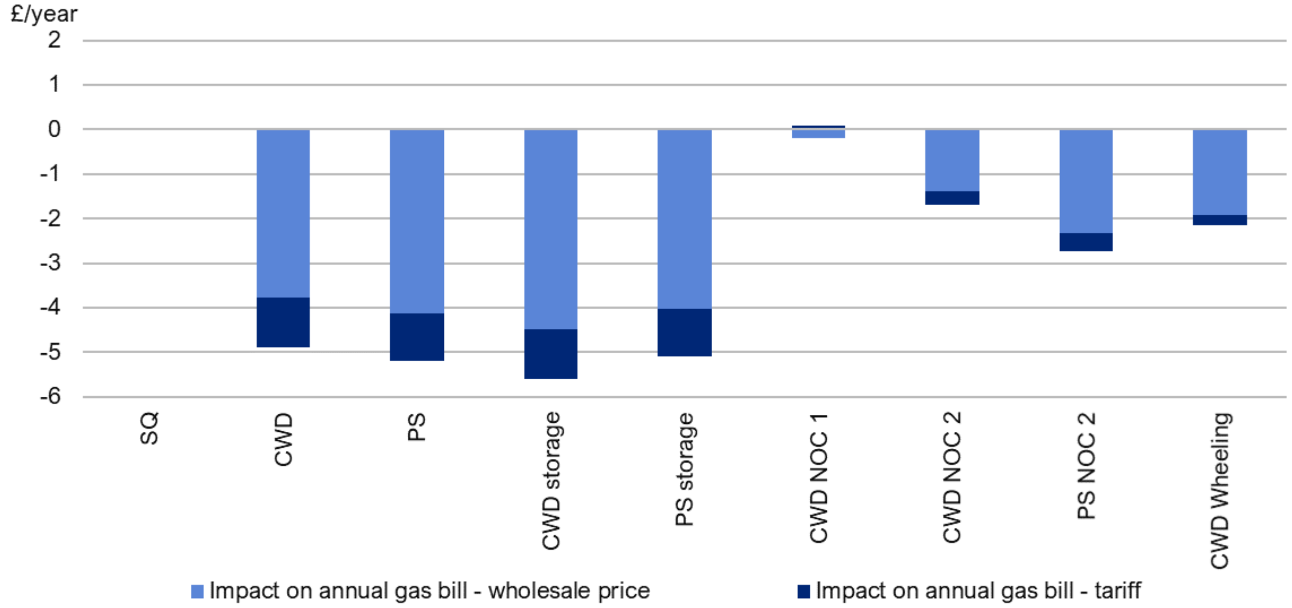


Figure 3.15: Estimated gas bill impact for lower quartile consumption domestic gas consumers (TD, 2030-31, £18/19)



[53] In practice, there is likely to be a difference between consumers who have median (or interquartile) gas and electricity consumption. However, we consider gas and electricity together to present an estimated combined effect of the two impacts.

Figure 3.16: Estimated gas bill impact for upper quartile consumption domestic gas consumers (TD, 2030-31, £18/19)



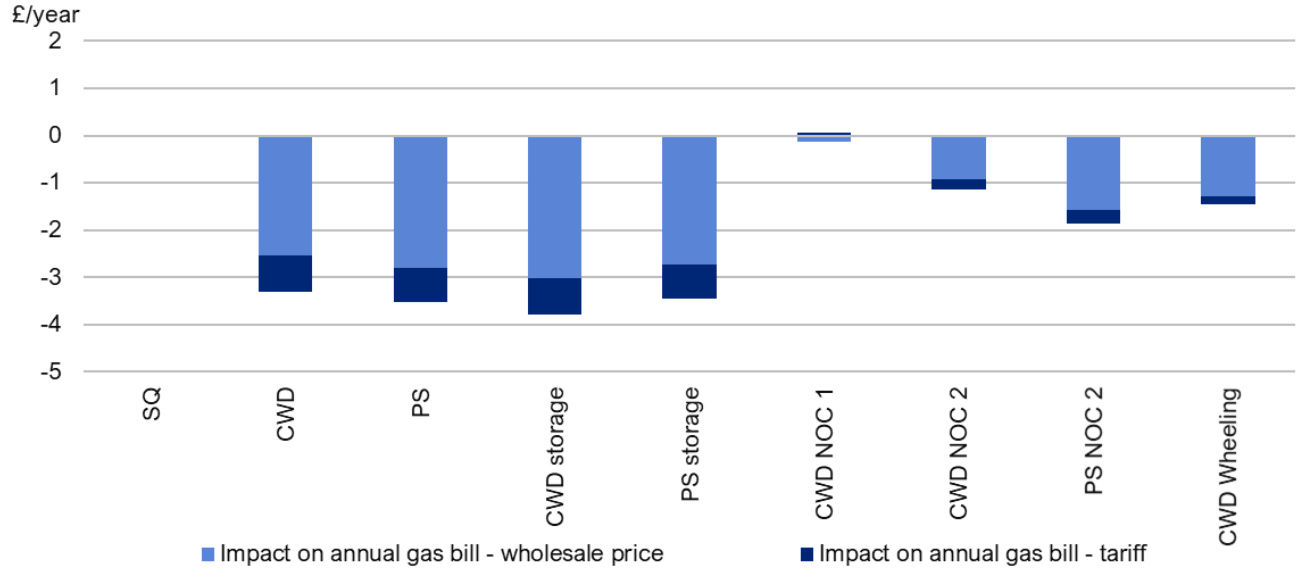
Driven by the decrease in wholesale gas market prices, we see a reduction in bills across all options. The bill impacts reflect the extent of the reduction in the wholesale gas price. Therefore, the reduction in bills is largest under the CWD Storage option.

The direct impact of the GDN exit tariff (see Figure 3.4) also generally results in a decrease in bills. The reduction in bills resulting from the tariff change is greatest for those options where there is no cost recovery required from the existence of a NOC. In the case of NOC Methodology 1, there is a marginal increase in the GDN exit tariff.

3.4.2. Impacts on vulnerable domestic consumers

We consider consumers who are financially vulnerable by taking consumption estimates of the median of the most fuel poor quintile gas consumers. We estimate the aggregate impacts on consumers in this quintile in Figure 3.17 and also comment on how the impacts may vary by region.

Figure 3.17: Estimated gas bill impact for the most fuel poor quintile domestic gas consumers (TD, 2030-31, £18/19)



The impacts on bills of consumers are proportional to the consumption levels of the most fuel poor quintile consumers. As consumption of the most fuel poor quintile median consumer is relatively similar to the median consumers, we observe a similar reduction in the bills of this segment of consumers under all options.

Regional variation in impacts

The majority of the impacts on vulnerable consumers will be through the changes in the wholesale gas price. While these may be passed onto consumers to a greater or lesser extent depending on supplier structures, we can assume that regional differentiation of the wholesale gas price impacts will be relatively low.

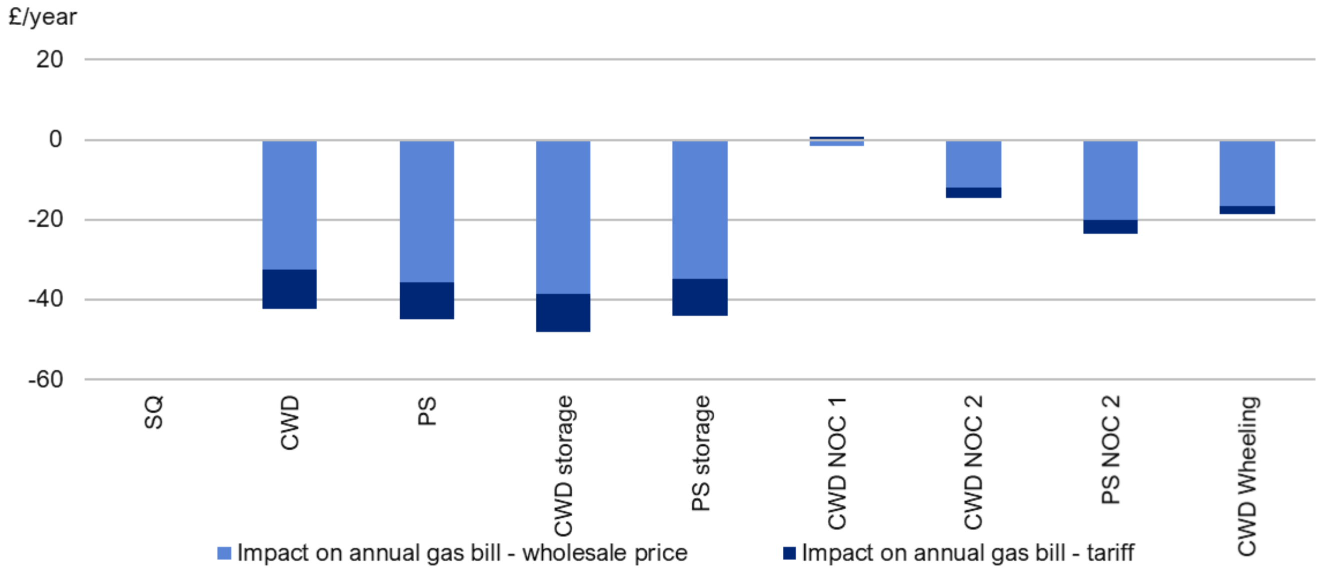
However, under a CWD methodology, the proportion of the bill impact related to the GDN exit point tariff will be subject to regional differentiation, as presented in Section 3.2.3. Depending on the location of the consumer, the option may result in an increase or decrease in the tariff component of the bill relative to the status quo. The magnitude of these tariff impacts can be expected to be small relative to the impacts of the wholesale gas price as shown in Figure 3.17.

3.4.3. Non-domestic consumer bill impacts

We consider bill impacts for non-domestic consumers based on median gas consumption of different consumer types. We present bill impacts for LDZ-connected I&Cs and NTS-connected non-domestic consumers separately.

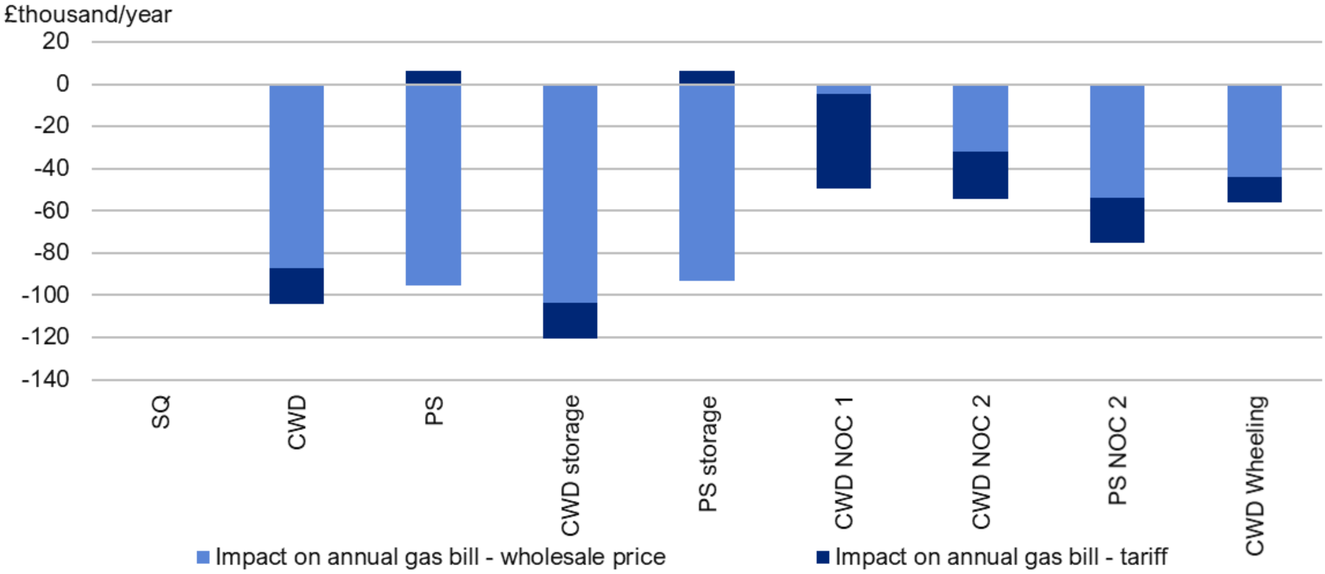
We show the combined gas price and tariff impacts for LDZ-connected non-domestic consumers in Figure 3.18, and for NTS-connected I&C consumers in Figure 3.19.

Figure 3.18: Estimated gas bill impact for the median non-domestic consumer connected to the LDZ gas network (TD, 2030-31, £18/19)



For LDZ-connected I&Cs, the impacts are proportionate to those observed for domestic consumers given that the mechanisms are the same – i.e. changes to the gas market price and GDN exit tariff impacts. However, the impacts are magnified given the higher consumption levels.

Figure 3.19: Estimated gas bill impact for the median non-domestic consumer connected to the NTS (TD, 2030-31, £18/19)



Considering the impacts on NTS-connected I&Cs, we see that the impacts of the wholesale gas price are proportionate to those observed for LDZ connected consumers. However, the impacts of the tariff methodology can be quite different. We observe the trends identified in Section 3.2.2, in which NTS-connected I&Cs are impacted by the choice of RPM. They face tariff increases under the PS in combination with the loss of the OCC shorthaul product. However, we observe reductions in the tariff under the CWD options even without a shorthaul product in place. We observe that many I&Cs benefit from a significant discount to their capacity tariffs under CWD NOC Methodology 1 and NOC Methodology 2 (PS and CWD). However, eligibility restrictions mean that they face a slight increase in the average tariff under the Wheeling Methodology relative to the equivalent CWD RPM without a NOC.

3.4.4. Electricity consumer bill impacts

In this section, we estimate the impacts of the changes in gas tariffs on electricity consumer bills via the effects on the wholesale electricity price (see Figure 3.11). This results from a combination of the change to the wholesale gas price and of the particular tariff impacts on gas-fired power stations under each option.

We estimate the impacts on the median bill of a domestic electricity consumer in Figure 3.20,[54] and the impact on the median non-domestic distribution-connected electricity consumers in Figure 3.21. As a result of the impact on the electricity market prices observed previously, electricity bills decrease under all options.

[54] We also estimated impacts on the most fuel poor quintile of domestic electricity consumers. As the median electricity consumption of these consumers is very similar to the median consumption of all domestic electricity consumers, we observe very similar reductions in bills for both types of consumer.

Figure 3.20: Estimated electricity bill impact for the median domestic electricity consumer (TD, 2030-31, £18/19)

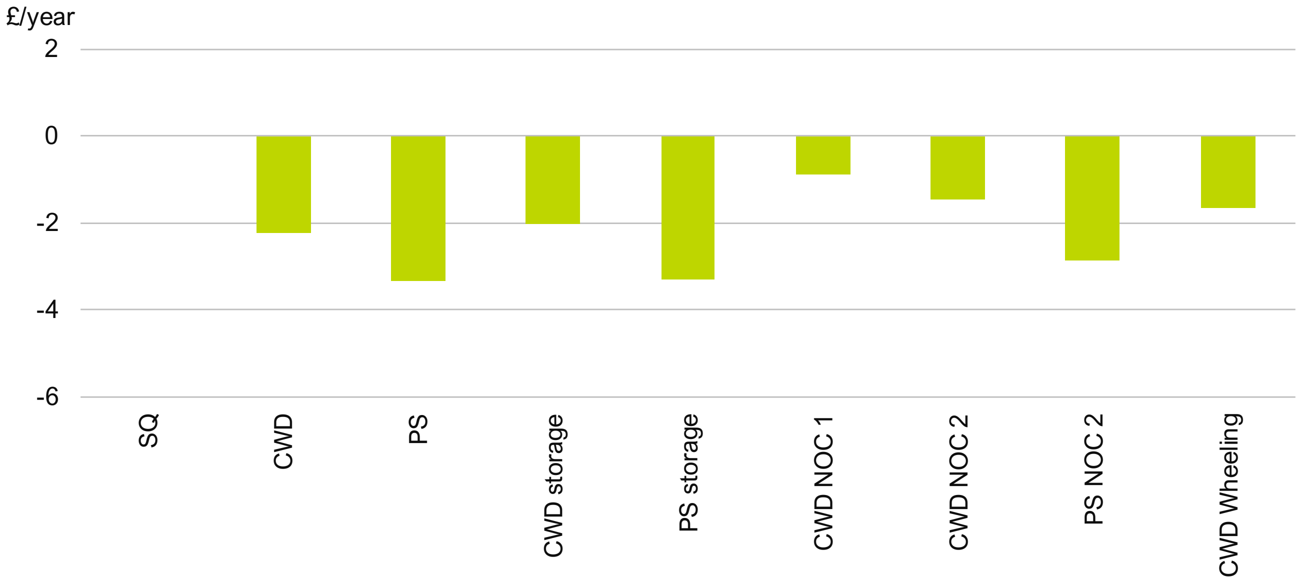
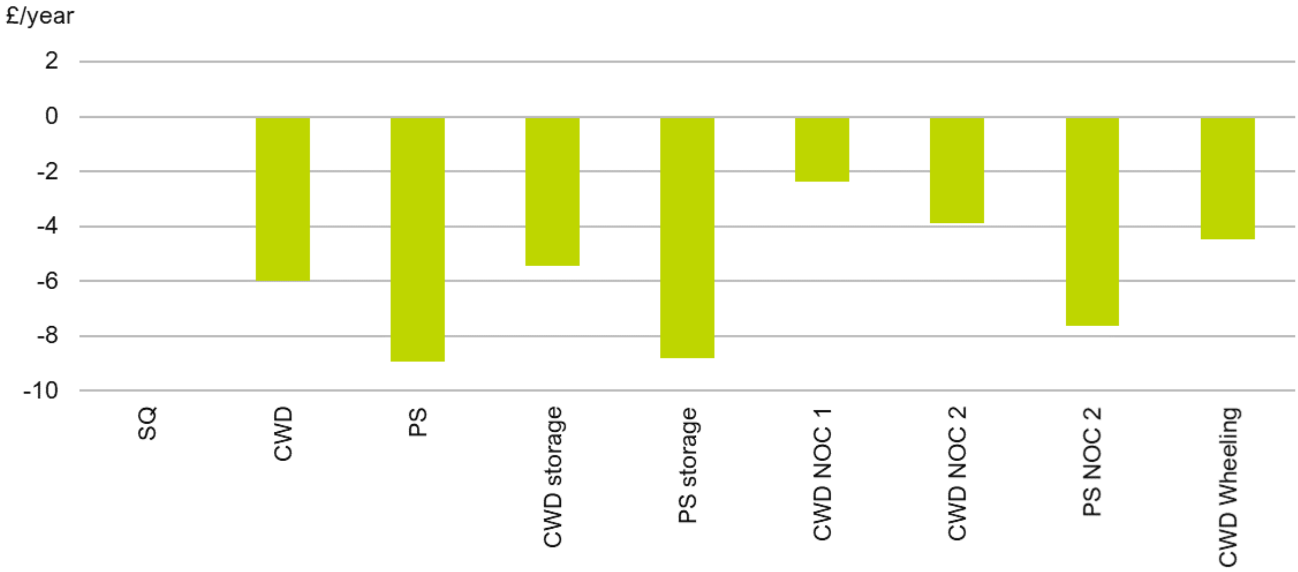


Figure 3.21: Estimated electricity bill impact for the median non-domestic electricity consumer (TD, 2030-31, £18/19)



3.4.5. Impacts on gas-fired power stations

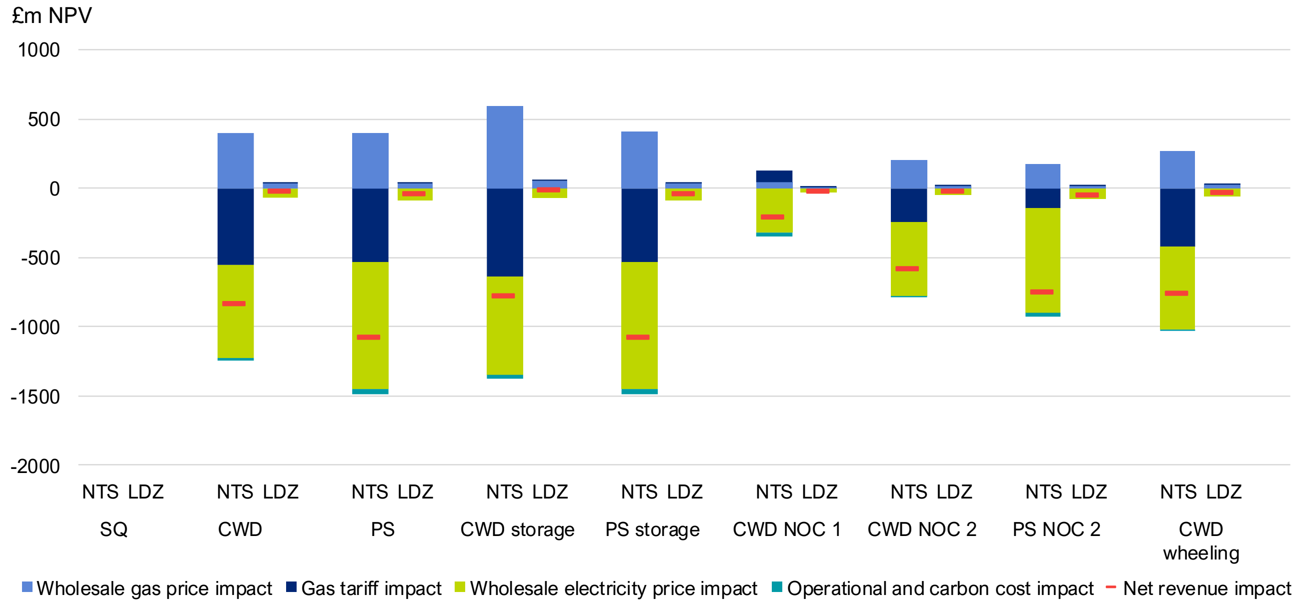
We also considered the potential changes in revenues for power stations. We present impacts for two types of generators:

- generators connected to the NTS, and
- generators connected to the LDZ.

The net revenue impact on gas-fired power stations is calculated based on revenues from generated electricity sold at the wholesale electricity price, after taking into account the cost of gas (including the wholesale gas price and the transmission tariff) and operational and carbon costs.

We show the collective estimated impacts on GB gas-fired power stations in Figure 3.22.

Figure 3.22: Impacts on revenues of GB gas-fired power stations (TD, 2022-2031, NPV, discounted to £18/19)



We find that revenues for power stations are lower under all options, relative to the status quo, and that the reduction in revenues is greater under the PS than the CWD RPM. To explain this impact, we consider the drivers behind power station revenues. As consumers of gas, power stations benefit from a decrease in the wholesale price of gas. On the other hand, power stations collectively face a reduction in revenues as a result of the decrease in the wholesale electricity price. Whether the negative impact of a lower electricity price outweighs the positive impact of cheaper gas depends on the level of tariff dispersion.

Assuming constant per unit operational and carbon costs, the only two variables which impact on the cost of production between power stations is the power station efficiency and the gas tariff. Where tariff dispersion is higher, dispersion of the input costs of gas-fired power stations is also likely to increase. Therefore, the tariff increase may often lead to slightly higher costs for the marginal unit, while a reduced tariff may lead to lower input costs for some inframarginal units. As a result, the marginal price of electricity is likely to increase slightly while inframarginal units may, on average, benefit from a slight increase in margins.

Figure 3.4 shows that tariff dispersion is greatest under the status quo, followed by those options with a CWD RPM. There is no dispersion by design under the PS RPM. The differing levels of tariff dispersion therefore help to explain why collective power station surplus is greatest under the status quo, followed by the CWD and then PS options.

Where a NOC is available, some power stations benefit from the tariff discount and, hence, tariff dispersion is higher than those options where there is no NOC. The reduction in revenues is therefore lower in these cases.

Under all options, we observe a slight increase in total operational and carbon costs, which results from a slight increase in generation to meet the increased electricity demand.

The results for LDZ-connected generators are similar but significantly smaller in magnitude, partly given lower levels of capacity. As LDZ-connected generators cannot benefit from the NOC, the only impacts on revenues under those options is related to the impacts on the gas and electricity prices, which are broadly similar across the different options.

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3.5. PRODUCER REVENUES

In this section, we consider the impact on revenues for gas producers, interconnectors and storage facilities. For each, we summarise the approach that we adopted for evaluating producer revenues and provide results.

It is important to note that our analysis is limited by the extent of the cost data that was available to us. Hence, we have relied on a number of assumptions in our analysis, and all revenue estimates should be considered as indicative only.

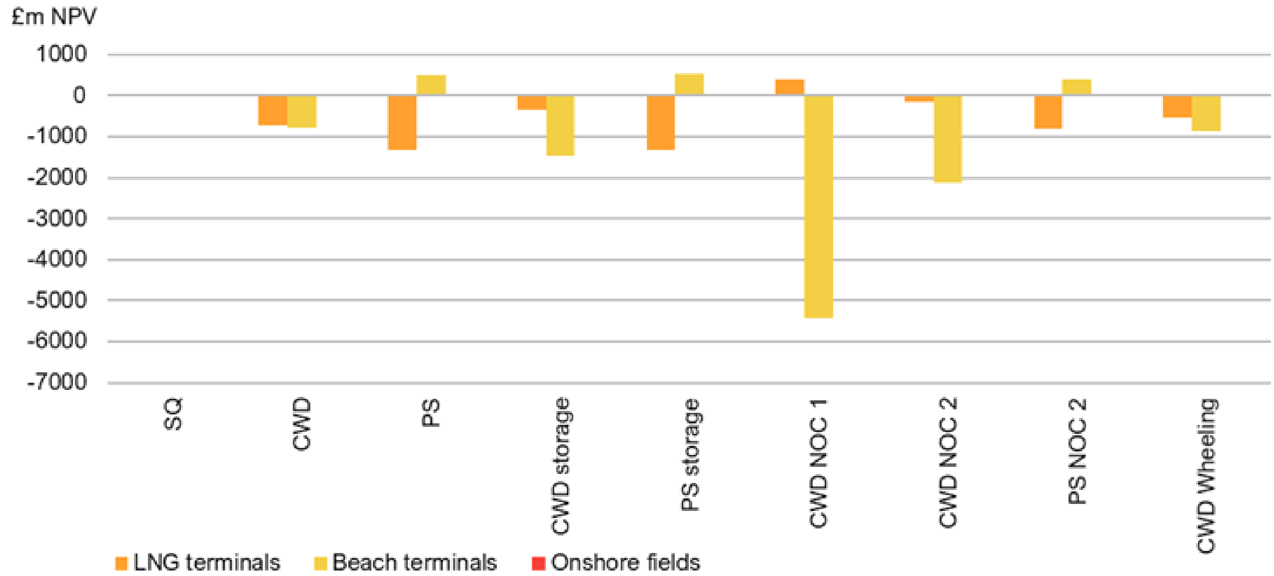
3.5.1. Impacts on beach terminals, onshore fields and LNG terminals

We estimate the gross revenues for producers and LNG terminals by pricing flows of entry gas at the prevailing wholesale gas price and subtracting estimated entry tariffs.[55]

It is important to note that we do not consider the option value of selling gas to other markets,[56] or the remaining value of gas held in store which could be sold at a later date.[57] Our results therefore only represent direct impacts relating to GB gas sales (and tariff impacts) within the period 2022-31. The net impact on these types of producer over a longer time period would therefore be significantly less than the impacts estimated below, given the value of gas sold to other markets or the retained value of gas not sold.

We present expected revenue impacts on LNG terminals, beach terminals[58] and onshore fields in Figure 3.23.

Figure 3.23: Impacts on revenues of LNG terminals, beach terminals and onshore fields (NPV, 2022-2031, £2018/19)



Our analysis shows that producers generally see revenue reductions under the modification proposals. This is despite the potential for a reduction in the tariffs at these entry points, as shown in Figure 3.3, and results from the reduction in the wholesale gas price.

[55] This approach effectively focuses on shipper revenues. Under the assumption that production costs do not change from one NTS charging option to another, the impact on shipper revenues represents the producer surplus. This is a reasonable assumption given that upstream costs are unlikely to be affected by changes in the NTS charging methodology.

[56] For example, gas held in Norwegian gas fields may be sold to other markets in the case that it is sold in the GB market.

[57] Note that for gas storage facilities, we do price gas held in store at the start and end of the period at the prevailing NBP price.

[58] NB: 'Beach terminals' include Norwegian gas flows to GB.

While the relatively high gas price under CWD NOC Methodology 1 allows LNG terminals to increase revenues relative to the status quo, the disproportionate impact that the methodology has on the entry tariff at beach terminals (see Figure 3.3) means that they reduce flows, and are substituted by other sources of entry, in particular interconnector entry flows (see Figure 3.24).

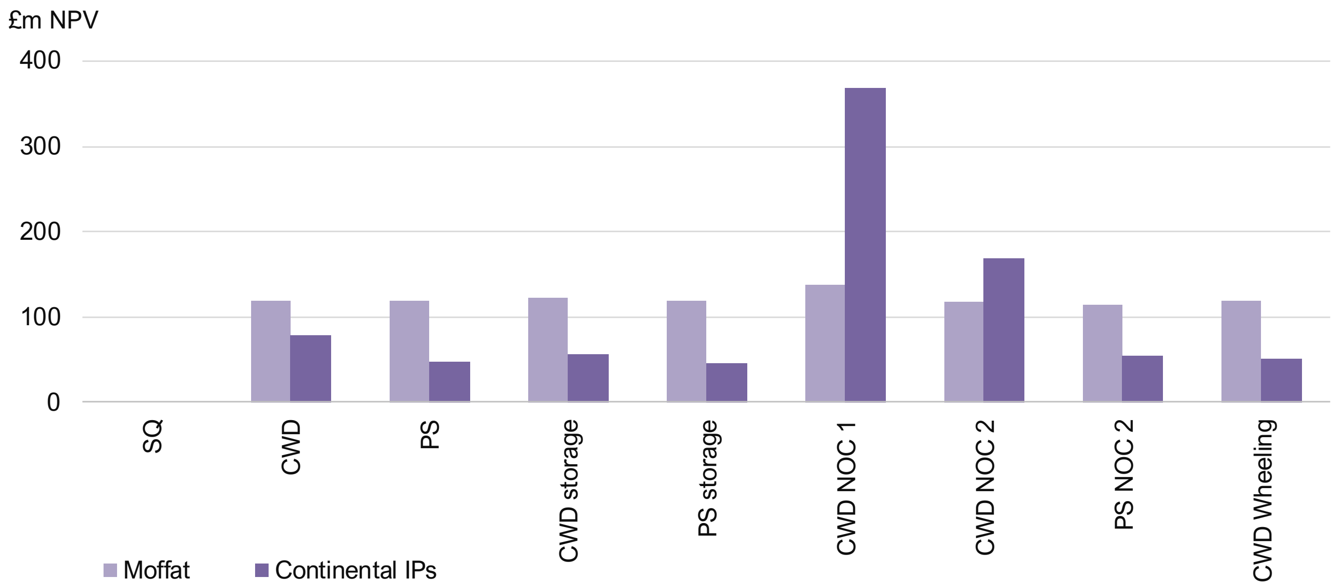
The benefits of the PS methodology relative to the CWD for beach terminals is also apparent. Under a CWD methodology, tariffs are higher for some beach terminals, where flows reduce as a consequence. This leads to a substitution by other sources of gas.

3.5.2. Impacts on gas interconnectors

We calculate the gross revenues for interconnectors by multiplying the gas flows over the interconnectors by the price differential between markets and netting off the entry or exit tariffs under each option.[59] Given a lack of cost data, we did not attempt to incorporate operational costs into our revenue estimates.

We consider IUK and BBL together given the correlation in the Dutch and Belgian wholesale prices. We assume bidirectional flow capability for BBL.

Figure 3.24: Impacts on revenues of Moffat and continental gas interconnectors (NPV, TD, 2022-2031, £2018/19)



We identify an increase in revenues for all interconnectors, and under all options, relative to the status quo, but the key drivers for this may differ between the options considered.

The revenue impacts for interconnectors are driven by three factors:

1. *Changes in tariffs*: Our tariff results suggest that all options result in a significant reduction in the tariffs at interconnector entry points in comparison to the status quo. The choice of RPM can impact the reduction in entry tariffs further. As shown in Section 3.2.4, tariffs are lower for interconnectors under the CWD RPM than under the PS.
2. *Changes in volume of flows*: The impact of lower tariffs is that interconnector flows sometimes displace gas flows from other sources (e.g. beach terminal flows). This is particularly the case under the CWD NOC

[59] As before, this approach effectively focuses on shipper revenues

Methodology 1 option, where we see a large increase in flows from interconnectors to the Continent, replacing entry flows from beach terminals.[60]

3. *Changes in the wholesale gas price*: In our modelling, the majority of gas flows over the bidirectional interconnectors are into GB. Where the GB gas price is lower, this would therefore result in a lower price differential between GB and the continent and hence a reduction in interconnector revenues, all else equal. As we explain below, this relationship does not apply to Moffat.

Moffat revenues

Moffat represents the marginal unit of gas in Ireland throughout the time horizon of our modelling. This means that any changes in tariffs and GB wholesale gas price movements are largely passed through to the Irish wholesale gas market price. While price movements could impact on gas demand in Ireland, and hence Moffat flows, we observe relatively flat exit flows to Ireland under all options, suggesting that the change in gas demand is small. Therefore, Moffat revenues remain relatively constant (including under the Wheeling option, which provides a 95% 'Ireland Security Discount' on the exit capacity tariff at Moffat). Rather than Moffat revenues being affected, any reduction or increase in the Moffat tariff is passed directly onto Irish gas consumers.

We observe this under all options with the exception of the status quo. Under the status quo, we find that Moffat revenues are lower than other options. This is driven by the use of shorthaul.

As shown in Figure 3.25, under the status quo, 100% of flows to Ireland utilise the shorthaul product and hence, benefit from the shorthaul discount. On days where flows on the shorthaul route are sufficient to meet Irish gas demand, our modelling results in the Irish gas price being *lower* than the GB gas price by an amount equal to the shorthaul discount.[61] The result in our modelling is that under the status quo, Moffat net revenues are lower than for other options.

This effect is not observed in other options either because a shorthaul product is not available, or because it does not represent a reduction in price relative to the standard tariff. Hence, we do not observe the same negative price differential as seen under the status quo and the net revenue impact compared to the status quo is positive.

Under CWD Methodology 1, while the Moffat shorthaul route is utilised, this is to a much lower extent than under the status quo. Additionally, the NOC is only sufficient to meet Irish demand on 0.3% of days of the year. On other days, the true marginal unit of gas in Ireland was provided through Moffat with the standard NTS capacity tariff, i.e. the shorthaul discount does not directly impact the Irish gas price. As a result, on days where the NOC is used but is not setting the Irish gas price, the interconnector makes 'inframarginal' rents on the proportion of gas provided using the NOC product. This explains the slightly higher net revenue observed under CWD methodology 1 in comparison to other options.

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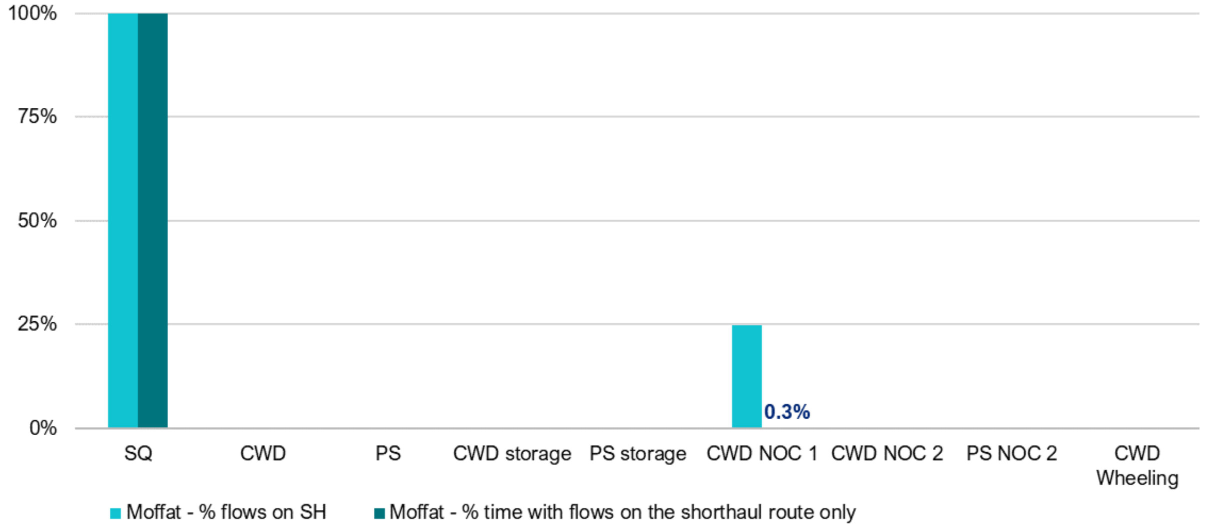
[60] The negative revenue impact on beach terminals (Figure 3.23) appears to be much larger than the combined positive revenue impact on the continental interconnectors. The reason for this lies in the fact that beach terminal revenues reflect the full GB wholesale gas price, whereas interconnector revenues (Figure 3.24) are based on the price *differential* between the GB wholesale gas price and the wholesale gas price of the neighbouring market. In practice, some facilities may be able to sell gas to other markets. Alternatively, the gas which is not sold within the period being considered would retain a value in future years and so the impact on revenues would be significantly less than that observed here. In effect, for beach terminals, we only consider GB gas sales in the period 2022-31.

[61] While these results may over-estimate the direct impact of shorthaul on the difference between the GB and Irish gas market price, it is possible that this phenomenon could lead to inefficient flows in practice. Ofgem has previously investigated the instance of 'flows against price differentials' for the continental interconnectors and the role that the GB gas charging arrangements may play in this. See: Ofgem, July 2013, Further analysis and next steps: review of the gas interconnectors between Great Britain and the Belgian and Dutch markets.

Figure 3.25: Average annual percentage of Moffat flows on the shorthaul route, and proportion of time that these flows are sufficient to meet Irish demand (TD, average over the period 2022-2031)



Bidirectional interconnector revenues

Revenues of bidirectional interconnectors increase relative to the status quo under all of the options. The increase is generally higher under the CWD options in which the entry tariff at Bacton is lower. This allows interconnector entry to become more competitive, increasing flows over the interconnector relative to the PS RPM.

Compared to the CWD option, the inclusion of an 80% storage discount results in a notable decrease in bidirectional interconnector revenues. This is due to a combination of the lower wholesale gas price which reduces the price differential between regions and a small amount of substitution of interconnector entry flows with entry from storage. While both interconnector and storage entry face higher tariffs under the PS, compared to CWD, the impact on interconnectors is more pronounced, resulting in a replacement of some interconnector entry flows by beach terminal and storage flows.

Impacts of the Wheeling option

Under the Wheeling option, we do not observe significant use of the Wheeling NOC product by the interconnectors. This is partly due to the fact that the price differentials between the GB wholesale gas market price and the gas market price in the relevant neighbouring market is estimated to be mostly positive (in the Continent-to-GB direction) in our modelling. Therefore, very low quantities of gas flow from GB to the continent are observed.

In practice, we might expect the price differential between GB and the continent to vary to a greater extent, resulting in use of the Wheeling product for exit of gas through the interconnectors.[62] This may result in higher interconnector revenues, and greater use of the Wheeling product, than we estimate based on our modelling.

3.5.3. Impacts on gas storage facilities

Storage is used by gas shippers to both inject and withdraw gas from the NTS to arbitrage between low- and high-price periods. Assuming that storage facilities retain a proportion of the revenues from arbitrage, these revenues are likely to be a function of the level of gas price volatility in the market. For storage facilities that cycle a relatively small number of times over the course of the year, the seasonal spread may be the key driver, whereas for shorter-term storage, more granular price volatility may be more important.

In addition to gas price volatility, changes to the tariffs of gas storage facilities (Figure 3.6) also influence the volumes of flows into and out of storage facilities. Tariff reform has quite different impacts on gas storage facility

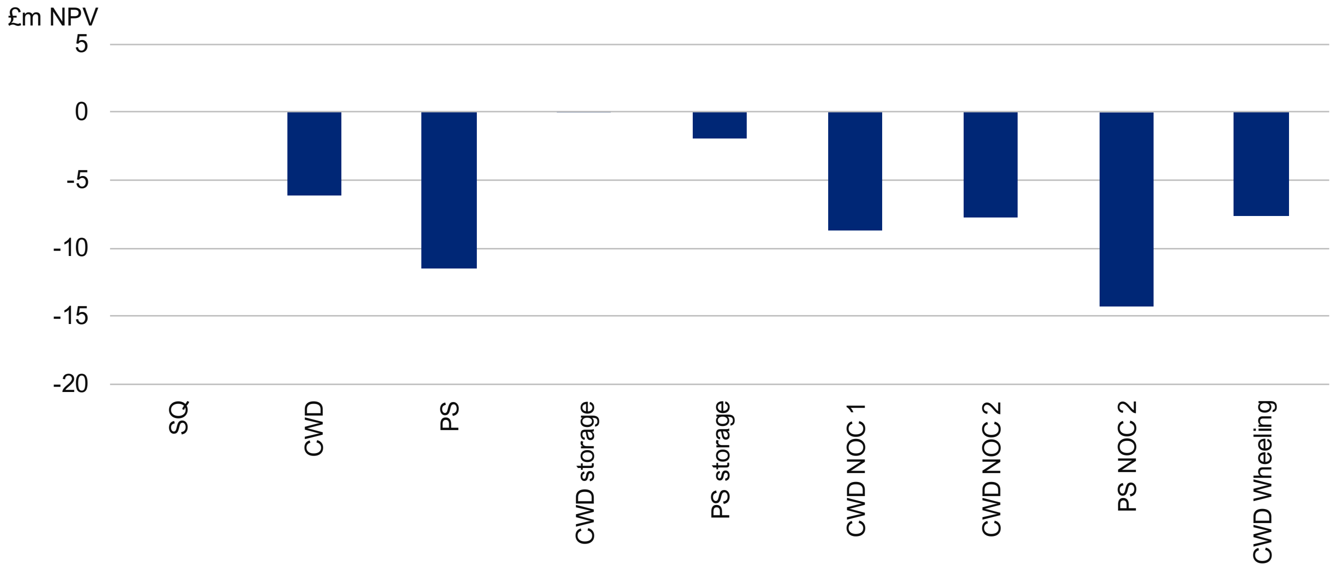
[62] Our gas market model is deterministic, and optimises at daily granularity, assuming perfect foresight. This may underestimate the role of assets who respond to within day volatility in gas prices (including gas storage facilities and interconnectors).

entry and exit points. For example, Figure 3.6 shows that annual tariffs at storage entry are smaller under the CWD RPM while annual tariffs at exit are generally smaller under PS.

In practice, the gas which enters and exits from a gas storage facility will remain balanced over the longer term. However, the balance of supply and demand over the course of a year may vary depending on prevailing gas prices and the expectations of market participants as to future gas prices. Given this relative balance of flows, storage revenues are more significantly affected by small changes in assumptions regarding flows into and out of storage over the course of the year. In this context, we note a more significant level of uncertainty of results for gas storage revenues in comparison to other entry and exit points.

Based on the modelled flows, we present the direct impacts of the tariff changes for GB gas storage collectively in Figure 3.26. This shows a wide range of impacts relative to the status quo. Under all options save for the CWD RPM with an 80% storage discount, we estimate that changes to tariffs at storage facilities would lead to a reduction in revenues. Our modelling suggests that the impact of the tariff would be greater under those options based on a PS RPM in comparison to CWD, and when a NOC is included. When an 80% discount for storage entry and exit is introduced the impact of changes to tariffs are significantly smaller and result in a small positive impact when coupled with the CWD RPM.

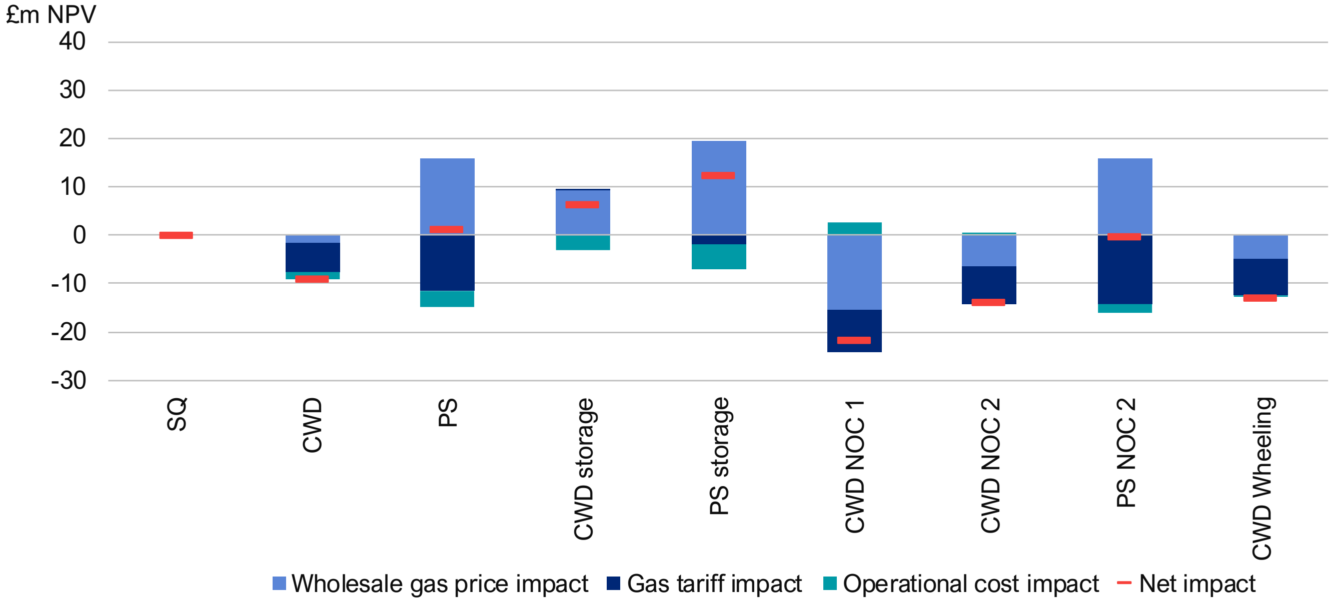
Figure 3.26: Direct impacts of changes to the tariff on revenues of collective GB gas storage facilities (no market price impacts included) (NPV, 2022-2031, discounted to £18/19)



We combine estimates of the direct tariff impact with changes in revenues that may result from arbitrage of gas and the wholesale gas price in Figure 3.27. Given that this revenue is a result of the finely balanced injections and withdrawals from storage, we consider it to be very sensitive to market conditions. We therefore focus on the direct impact of the tariff itself when considering the potential for the tariff options to impact on gas storage investment and closure decisions in Section 4.1.2.

To estimate the revenue impacts for gas storage, we calculate the value of gas withdrawn from storage units and deduct the price of gas injected into storage, including our estimates of injection and withdrawal costs and the combination of the entry and exit tariff. We also deduct the value of gas which was already in store at the start of the gas year and add the value of gas remaining in store at the end of the year.

Figure 3.27: Impacts on total revenues of collective GB gas storage facilities (NPV, 2022-2031, £2018/19)



As for other market participants, we see that the impacts of the wholesale gas price may be significant relative to the direct revenue impacts of the revised tariff. For example, while the tariff is significantly lower under the CWD RPM compared to the PS RPM, revenues relating to arbitrage of the gas market price are higher under the PS. While gas storage faces a higher tariff under the PS than CWD for entry flows, so do some of its competitors (e.g. interconnection) and as a result we observe higher entry flows of gas from storage facilities onto the system under the PS RPM. In combination, this leads to higher revenues for gas storage facilities under the PS relative to CWD RPM.

The chart shows the benefits to gas storage of introducing an 80% storage discount. This has the combined effects of reducing the level of the transmission tariff and of encouraging greater flows from gas storage facilities relative to competing sources of entry, leading to higher revenues.

4. LONG-RUN ANALYSIS

While the analysis set out above considers static impacts based on a defined set of supply and demand conditions, tariff structures may also affect long-run decisions of market participants. This may include investment and closure decisions, as well as location and technology choice.

In this section, we consider the potential for changes in tariffs to impact on these choices by comparing the materiality of the changes in tariffs with wider commercial factors.

We also analyse the potential for network users to build bypass pipelines to avoid paying transmission tariffs, taking into account the availability and design of any NOC option.

4.1. Investment and closure analysis

We firstly consider the potential for transmission tariff structures to impact on investment and closure decisions, including the choice of where to locate on the system. We assess these impacts for gas interconnectors, storage facilities and gas-fired power generators.

4.1.1. Commercial gas interconnectors

While a lack of data on interconnector cost structures makes it difficult to assess impacts on interconnector profitability with accuracy, we set out estimates of the impact on gas interconnector revenues in Section 3.5.2.

Under the status quo, we estimate healthy positive revenues for continental interconnectors. Furthermore, though subject to market prices in GB and in other markets and interconnector variable costs, we estimate increases in revenues for bidirectional gas interconnectors relative to the status quo.

Baringa[63] has previously noted that financial statements of Interconnector UK for the financial year ending 31 December 2017[64] show that operating expenses accounted for 38% of total revenue, and that 40% of these operating expenses were allocated to depreciation of property, plant and equipment, which would not necessarily need to be recovered in full to avoid closure.

The existence of healthy revenues combined with the potential increase in revenues relative to the status quo means that we would expect interconnectors to continue to make sufficient revenues to cover essential operating expenses. We therefore consider it unlikely that any option would increase the likelihood of interconnectors exiting the market.

Nevertheless, some options may provide a stronger signal for infrastructure investment than others – for example, investment needed to introduce bidirectional flow capability for BBL. The potential for further investment may be strongest where revenues are relatively high, e.g. under the CWD RPM with NOC Methodologies 1 or 2.

4.1.2. Gas storage facilities

We considered the potential effects of the options on storage revenues in Section 3.5.3. As storage facilities both withdraw and inject from the NTS, the balance of revenues at storage facilities is particularly susceptible to assumptions on entry and exit flows and on the level of the gas market price. Given this relative uncertainty for revenues resulting from the wholesale market price, we focus instead on the tariff impacts which are likely to be less sensitive.

Apart from the CWD RPM with an 80% storage discount, for which we observe a small positive impact on revenues, impacts for gas storage resulting directly from the change to the entry and exit tariffs are negative under all options

[63] See: Baringa, December 2018, Gas Charging Review (UNC621) - Analytical support.

[64] See: Interconnector (UK) Limited, Annual Report and Consolidated Financial Statements for the year ended 31 December 2017.

relative to the status quo. Comparing options, we can observe that negative revenue impacts are lower where the CWD RPM is used, and where there is an 80% storage discount, as we would expect.

In Table 4.1, we present our estimate of the direct impact of tariffs under the options relative to the total revenues we estimate for storage facilities under the status quo (i.e. after deducting the costs of gas purchased at the NBP and deducting estimates of operational costs). This allows us to consider the relative proportion of existing storage revenues that could be eroded as a result of tariff reform.

Table 4.1: Percentage change in total storage revenues as a result of changes to tariffs (TD, NPV, 2022-31)

Option	Percentage change in revenues of gas storage facilities as a direct result of changes to entry and exit tariffs
SQ	N/A
CWD	-33%
PS	-61%
CWD storage	1%
PS storage	-10%
CWD NOC 1	-46%
CWD NOC 2	-41%
PS NOC 2	-76%
CWD Wheeling	-40%

Table 4.1 shows that the reduction in the NPV estimate of storage revenues under the status quo could be significant under several of the options. Without incorporation of an 80% discount, we estimate that the PS options could reduce revenues by more than 60%.

Applying a CWD RPM limits the reduction in revenues to some degree, however in the absence of an 80% storage discount, the loss of revenue remains above 30%. The PS option which includes an 80% storage discount results in a reduction in revenues of approximately 10% while combining a CWD RPM with an 80% discount results in a very small increase in revenues relative to the status quo.

While we previously noted the sensitivity of revenue results relating to the wholesale market impacts, Figure 3.26 provides some sense of the potential magnitude of wholesale price impacts relative to the tariff impact. This suggests that the market price impact could potentially outweigh the impact of the tariff in isolation. In addition, the direction of this impact could be negative or positive depending on market dynamics and substitution between sources of entry.

In summary, we estimate potentially significant impacts on revenues of storage facilities under a number of modification options. We do not have estimates of the fixed operating costs of storage facilities that would need to be covered in order to minimise risk of exit. However, where changes to tariffs reduce total storage revenues by the order of 40-75%, as observed under some options, we would assume that this may introduce challenges for some storage facilities in the market.

4.1.3. Gas-fired power stations

For gas-fired power stations, we consider both the potential impact on investment and closure, as well as the potential for changes to tariffs to impact on location decisions.

Investment and closure incentives

Investment

In order to assess the potential impact on investment and closure of gas-fired power stations, we compare the impact on revenues[65] to the levelised cost of electricity (LCOE)[66] for gas-fired generators, estimated by BEIS.[67] The findings from this analysis are set out in Table 4.2.

Table 4.2: Levelised impacts on gas-fired power station revenues (TD, 25-year project lifetime)

Option	Levelised impact (NTS-connected shorthaul generators, £/MWh)	Levelised impact (NTS-connected non-shorthaul generators, £/MWh)	Levelised impact (LDZ-connected generators, £/MWh)
CWD	0.88	0.33	0.25
PS	1.10	0.55	0.51
CWD Storage	0.84	0.20	0.13
PS Storage	1.10	0.55	0.51
CWD NOC 1	0.16	0.41	0.30
CWD NOC 2	0.58	0.38	0.32
PS NOC 2	0.75	0.61	0.58
CWD Wheeling	0.79	0.39	0.33

For an efficient H-Class CCGT commissioning in 2025, BEIS identifies a central estimate LCOE of £82/MWh and a range between £80/MWh and £83/MWh. Therefore, even at the highest level of impact for NTS-connected shorthaul generators (i.e. £1.10/MWh observed under the PS RPM) under the PS RPM, the impact on revenues would be small (approximately 1.3% of the LCOE). Therefore, we would only expect a change to tariff arrangements to impact on investment decisions at the margin.

BEIS's LCOE estimates for an OCGT commissioning in 2025 are significantly higher than for CCGTs (central estimate of £189/MWh for an OCGT operating for 500 hours of the year). Therefore, the potential impacts on investment decisions involving other gas-fired generation technologies is likely to be even smaller. For the same reason, impacts on LDZ-connected generation investment decisions are likely to be less significant.

Closure

Within our modelling, we observe positive profits for all types of existing power station which outweigh the potential impact of the tariff by some margin, after taking account of estimated gas, carbon and operational costs. We therefore consider it unlikely that tariff reform would increase the likelihood of power plant closure, except for marginal closure decisions.

In addition, we assess potential impacts on closure decisions, based on BEIS estimates of fuel, carbon and operations and maintenance costs only, taking a CCGT H-Class but this time commissioning in 2020. BEIS's central estimate in this case is £59/MWh. Again, considering the maximum potential effect of changes in revenues, we find

[65] We levelised revenues impacts over a 25-year project life, consistent with BEIS's LCOE methodology.

[66] This is the net present value of the unit-cost of electricity over the lifetime of a power generator.

[67] See: BEIS, November 2016, Electricity Generation Costs.

that this equates to just over 1.9%. Given that plant which is currently operating on the system is likely to be less efficient, and hence would face higher running costs, the impact of any tariff reform would constitute an even smaller proportion of costs. This reinforces our view that impacts on closure would only be observed at the margin.

Plant location

We can consider the impacts of the tariff arrangements on plant location by estimating the magnitude of tariff dispersion (i.e. the difference between the maximum and minimum tariff) and comparing it to other potential drivers of plant location. One important locational signal which is sent to power stations is the electricity Transmission Network Use of System (TNUoS) charge.

We illustrated the level of tariff dispersion in Figure 3.4. Under the status quo, the level of the tariff ranges between just over 0.01 p/kWh/day and just under 0.06 p/kWh/day. The level of tariff dispersion under the CWD is narrower than for the status quo and is zero by design under a PS RPM. Tariff dispersion for the standard capacity tariff is similar on average whether a NOC is used or not. However, plant at certain locations may benefit from the NOC discount increasing dispersion to some extent.

For embedded generation, the tariff differential is driven by the GDN exit tariff (also shown in Figure 3.4). Tariff dispersion is wider as a result of our assumption of overbooking of capacity at GDN exit points. Under the status quo, the tariff ranges by approximately 0.11 p/kWh/day. Under the CWD RPM options, the tariff range is between approximately 0.05 p/kWh/day and about 0.06 p/kWh per day where a NOC is included. As is the case for NTS-connected power stations, there is no tariff dispersion when the PS RPM is used.

We may therefore assume that, relative to the status quo, the locational signal sent by the exit tariff will be dampened under all options and will be eliminated under the PS RPM for both NTS and LDZ connected power stations.

In order to consider the impact of the reduction of tariff dispersion on plant location, we follow the approach adopted by Baringa[68] and compare the extent of tariff dispersion to the variation in TNUoS, assuming an indicative efficiency of a new CCGT of 56% and a load factor of 75%. We set out tariff dispersion in terms of £/MWh of electricity in Table 4.3.

Table 4.3: Difference between highest and lowest tariff for gas-fired power stations in £/MWh of electricity/day

Modification option	LDZ-connected power station tariff range (£/MWh of electricity/ day)	NTS-connected power station tariff range (£/MWh of electricity/day)
SQ	2.0	0.8
CWD	1.0	0.4
PS	0	0
CWD Storage	1.0	0.4
PS Storage	0	0
CWD NOC 1	1.2	0.5
CWD NOC 2	1.1	0.5
PS NOC 2	0	0
CWD Wheeling	1.1	0.5

Baringa estimated variation in the TNUoS for a power station with a load factor of 75% to be around £7/MWh of electricity, noting that this would be greater for less efficient power stations.

[68] See: Baringa, December 2018, Gas Charging Review (UNC621) - Analytical support.

Our estimates suggest that the maximum change in tariff dispersion relative to the status quo is observed when dispersion is completely removed as under the PS RPM. In this case the reduction in tariff dispersion is £2.0/MWh of electricity/day for LDZ-connected power stations and £0.8/MWh of electricity/day for NTS-connected power stations. The extent of change in tariff dispersion is approximately half of that observed for the PS RPM in the case that a CWD RPM is chosen.

While not insignificant, the change in tariff dispersion is expected to be a maximum of 29% of the dispersion of TNUoS charges for LDZ-connected generation and approximately 11% for NTS-connected generation. Given that there may be a number of other factors which are important to the consideration of where to locate any new power station, we would expect the change to the tariff arrangements to only have an impact on decision making in the most marginal of cases, if at all.

We can also consider whether any new gas-fired power stations are more likely to locate on the NTS or LDZ as a result of the tariff options. Analysis of the impact on LCOE suggested that the impacts of tariff arrangements would be relatively small for all power stations independent of the voltage level of connection. However, we observed proportionately higher tariff impacts for NTS-connected power stations than for LDZ-connected power stations. Tariff reform may therefore introduce a marginal incremental incentive to locate on the LDZ rather than NTS. This echoes analysis of revenue impacts in Section 3.4.5, which showed that impacts of changes on the gas price are common to both levels of connection, while tariff impacts are generally negative for NTS-connected power stations but marginally positive for LDZ-connected power stations.

4.2. Bypass investment

We estimated the costs and savings to network users of building a bypass pipeline. This would allow them to avoid paying for use of the gas network for a given entry-exit combination. For all those network users who made use of the OCC product in the gas year 2017-18 ('modelled routes'), we analysed whether investment in a bypass pipeline would be profitable within a five-year time horizon.

Given limited availability of data, our analysis does not take into account several costs which we would expect to be a part of commercial considerations regarding potential bypass investment. For example, we have not included land, planning and contractual costs, all of which may be significant in practice. Neither have we accounted for the fact that those who decide to bypass the network could have their gas connection to the NTS removed, therefore introducing additional risk of flow constraints either due to supply or network restrictions.

We compared the NPV of the costs and savings (i.e. avoided tariffs) of investing in a bypass pipeline to determine whether there may be a commercial incentive to bypass the NTS.[69]

Because of our conservative assumptions regarding the costs of bypassing the NTS, we do observe some risk of bypass under the status quo. In order to introduce an appropriate counterfactual, we compare results of bypass risk under the options to the status quo and present results accordingly.[70] Where our modelling estimates that more

[69] Our methodology is explained in further detail in Section 0.

[70] Given our conservative cost assumptions, our analysis suggests that five shorthaul routes may bypass the NTS under the status quo arrangements. As bypass of the system from these users has not yet been observed, this supports our expectation that the estimates of bypass made for all options represent an overestimate or upper bound of likely bypass in the future.

routes would bypass the NTS than observed under the status quo, we report the number of routes and the volume of flows that may bypass the NTS as a result. We present the results of this analysis in Table 4.4.

Table 4.4: Indicative number of additional routes and flow volumes the present a risk of bypass assuming a five-year payback time relative to the status quo (TD, 2030-31)

Tariff option	Number of routes additional to that observed in the status quo that present a credible risk of bypass[71]	Modelled flows additional to that observed in the status quo that present a credible bypass risk (TWh/year)
CWD	2	11.7
PS	3	25.3
CWD Storage	2	11.7
PS Storage	3	25.3
CWD NOC Method 1	0	0.0
CWD NOC Method 2	0	0.0
PS NOC Method 2	0	0.0
CWD Wheeling	1	7.3

Our results suggest that the number of routes and the amount of flows that could profitably bypass the NTS are the same or less than the status quo where NOC Methodology 1 or 2 is included, suggesting that these options cover bypass risk at least as well as the status quo. In the case of the CWD Wheeling methodology, we observe a single additional risk of bypass, in part due to the eligibility criteria which are included in the option.

In the absence of a NOC, our analysis suggests that the potential for profitable bypass may increase slightly. For the CWD RPM, we observe an additional two routes that may present a credible risk, representing flow volumes of approximately 11.7 TWh per year. This increases to three routes and 25.3 TWh per year when a PS RPM is used. The inclusion of a storage discount does not impact on bypass risk.

The fact that we find that bypass is more likely under the PS than CWD RPM reflects the balance of the tariffs which the most common users of the OCC would face in the absence of a NOC. Some users (e.g. power stations on average) would face a lower tariff under the PS. However, on balance, a majority of those who are more likely to bypass the system (i.e. at relatively short distances between entry and exit) face a lower tariff under the CWD methodology.

Based on the likelihood of bypass identified above, we considered the amount of lost revenue that may result from bypass of the NTS. We calculated the total value of tariff revenue that these market participants would no longer contribute if they were all to bypass the NTS. We assume that they would otherwise pay capacity charges at the lowest possible rate (e.g. at the level of their standard NTS capacity tariff under the CWD or PS methodology, or using the NOC, if available and cheaper). Note that, for this reason, the relationship between the volume of flows that bypasses the NTS and the lost revenue associated with this bypass is not the same across options. This relationship instead depends on the particular routes that may have bypassed the NTS and on the revenue that they would have provided under the alternative tariff option available.

Our estimates of lost revenue resulting from system bypass are shown in Table 4.5.

[71] There is a total of 48 routes that made use of the OCC in the gas year 2017-18. These are the routes that we have modelled within the bypass modelling.

Table 4.5: Indicative revenue that could be lost due to bypass (TD, 2030-31)

Tariff option	Potential lost transmission revenue if all additional credible bypass routes choose to bypass the NTS (TD, 2030-31, £m 18/19)
CWD	31.9
PS	36.1
CWD Storage	32.0
PS Storage	36.2
CWD NOC Method 1	0.0
CWD NOC Method 2	0.0
PS NOC Method 2	0.0
CWD Wheeling	18.6

Our analysis of revenue recovery implications reflects the amount of flows that may bypass the system, as shown in Table 4.4, and the contribution that these routes would make to revenue recovery if they did not bypass the NTS.[72] While the volume of flows that may bypass the NTS under the PS option is more than double that observed under the CWD, the estimated lost revenue recovery is only slightly larger.

4.2.1. Analysis of NOC design

A shorthaul product was introduced within the GB tariff arrangements to reduce the risk of bypass of the NTS. Based on that objective, an effective and proportionate shorthaul product would be structured to achieve two things:

1. The shorthaul product should only be available to those network users who present a credible risk of bypassing the network in the absence of the product.
2. The shorthaul product should provide a discount which is just sufficient to deter bypass without providing any additional subsidy.

In theory, both objectives would be achieved by setting the shorthaul discount so that the tariff paid is just below the levelised cost of bypassing the system for each individual network user. In practice however, measuring the levelised cost of bypass at an individual user level would be very challenging, and would depend on the specific circumstances of the network user in question.

Using our results of expected take-up of the NOC and comparing them against our estimates of the potential for bypass, we conducted an indicative analysis of the extent to which each option is 'well-targeted' and proportionate based on these objectives.

We carried out analysis aligned with the two objectives set out previously:

1. **Appropriateness of targeting**: We measured lost revenue from network users that would be able to use the NOC (and would find it profitable to do so) but did not present a credible bypass risk based on our analysis. To consider risk of bypass without a NOC, we take the relevant RPM without a NOC – i.e. whether a route would present a risk of bypass under the CWD or PS RPM. An optimal NOC would set the level of lost revenue based on inappropriate targeting to zero.

2. **Appropriateness of the level of the discount**: Analysis of the appropriateness of the level of the discount is made up of two factors:
    a. The lost revenue from any network users who would continue to bypass the NTS despite provision of the NOC. We can measure this by assuming that the user would have paid capacity charges at the lowest possible rate (e.g. at the level of their standard NTS capacity tariff under the CWD or PS

[72] Driven by both the amount of flows and the level of the applicable capacity tariffs in the absence of bypass.

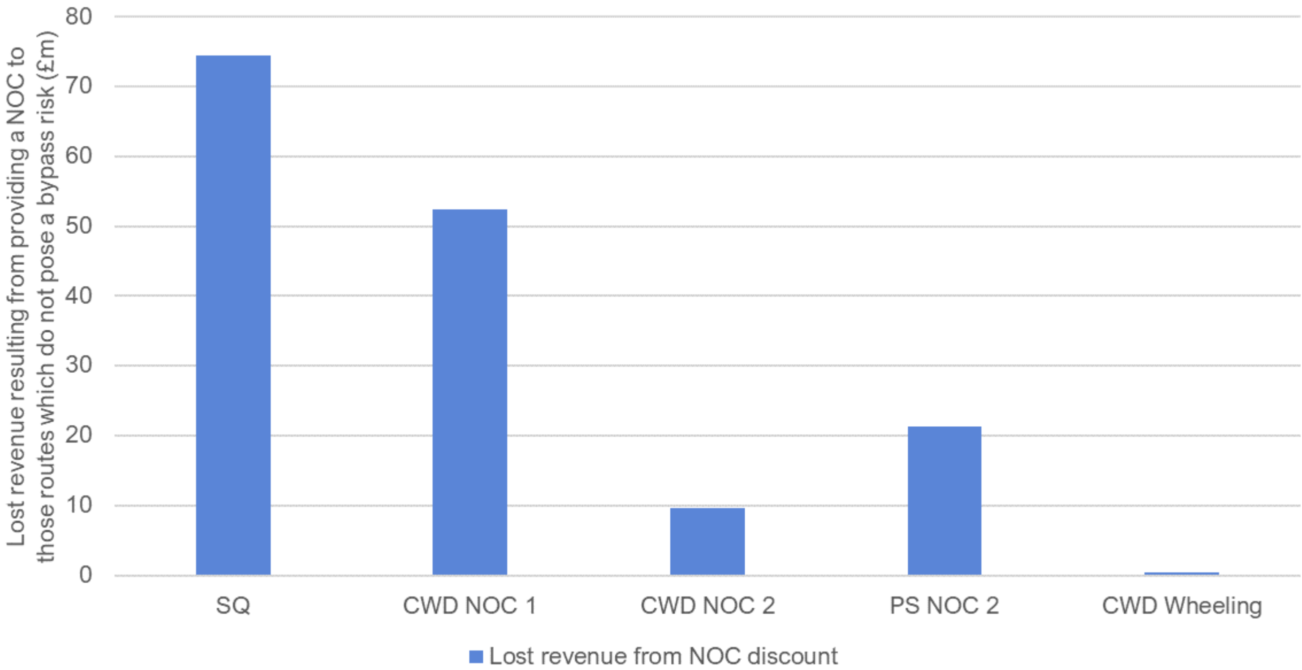
methodology, or using the NOC, if available and cheaper) had they not decided to bypass the NTS, An optimal NOC would set this to zero.

b. The lost revenue which results from providing the NOC discount to users who pose a bypass risk. We estimate this by taking the difference between the revenue that would have been recovered under the standard capacity tariff and the revenue that continues to be recovered under the NOC, only considering those routes that do present a risk of bypass in the absence of a NOC. Even under an optimal NOC, some lost revenue from the provision of a discount to avoid bypass would remain. Under an optimal NOC the level of lost revenue would be minimised however.

Appropriateness of targeting

We present results of our analysis of total lost revenue resulting from inappropriate **targeting** in Figure 4.1.

Figure 4.1: Annual lost revenue by providing the NOC to routes that do not present a risk of profitable bypass of the NTS (TD, 2030-31, £18-19, assuming required payback time of five years)



This analysis suggests that the OCC under the status quo provides a discount to a substantial volume of flow that does not pose a credible risk of bypass, thus leading to over £70 million of lost revenue recovery. CWD NOC Methodology 1 reduces the level of inappropriate targeting slightly but a significant loss of revenue remains.

Targeting improves under NOC Methodology 2 however some inappropriate lost revenue remains.[73] Targeting under the CWD RPM appears to be more reflective of bypass risk than when a PS RPM is used. The eligibility criteria applied to the Wheeling methodology leads to very small revenue recovery implications as a result of provision of a discount to users who do not pose a credible risk of bypass.

Appropriateness of the level of the NOC discount

We present results of our analysis in relation to the **level** of the discount in Figure 4.2. Under our analysis, an optimal NOC would set the potential for loss of revenue from bypass (the dark blue column) to zero, while the loss of revenue from the magnitude of the discount (the light blue column) would be minimised but could not be eliminated completely.

[73] Recall also that our estimated risk of bypass is likely to be an overestimate given that we do not include the full range of costs within our bypass function.

Figure 4.2: Annual lost revenue from those routes that present a credible bypass risk in the absence of the NOC (dark blue = revenue lost as a result of bypass, light blue = revenue lost as a result of the NOC discount from those presenting risk of bypass, TD, 2030-31, £18-19)

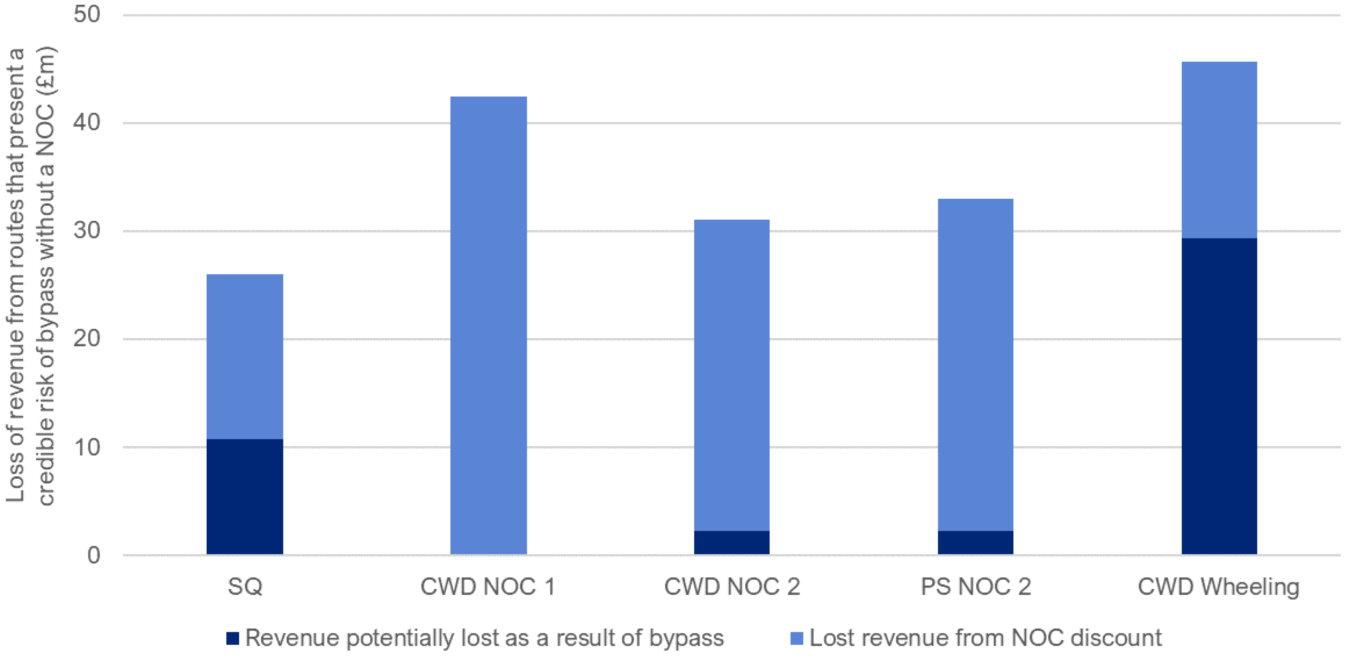


Figure 4.1 suggested that the status quo may be poorly targeted, providing a discount to several routes that did not present a credible bypass risk. Figure 4.2 suggests that some risk of bypass may exist under the status quo.[74] However, for reasons previously discussed, we consider the risk of bypass to be an over-estimate and so, would not expect to observe this level of bypass in practice.

For routes which present a risk of bypass in the absence of the OCC, loss of revenue from the shorthaul discount is lower than for NOC Methodologies 1 and 2.

Our analysis suggests that a substantial risk of bypass, and hence potential loss of revenue, remains under the CWD Wheeling methodology, partly due to the more limited eligibility that does not capture all routes for which bypass may be credible. Again, we note that the risk of bypass identified is likely to be an over-estimate, however.

While CWD Methodologies 1 and 2 reduce risk of bypass relative to the status quo, the level of lost revenue from provision of the discount remains sizeable at around £30 million per year.

Combining the results shown in Figure 4.1 and Figure 4.2, the total lost revenue from the choice of NOC (including risk of bypass) is smallest under CWD NOC Methodology 2, with the Wheeling Methodology and PS NOC Methodology 2 having slightly higher lost revenue levels. CWD NOC Methodology 1 appears to fare little better than the status quo in terms of the elimination of lost revenues from the use of a NOC.

[74] Remembering that for a number of reasons set out above, we would expect the risk of bypass presented here to be a conservative overestimate.

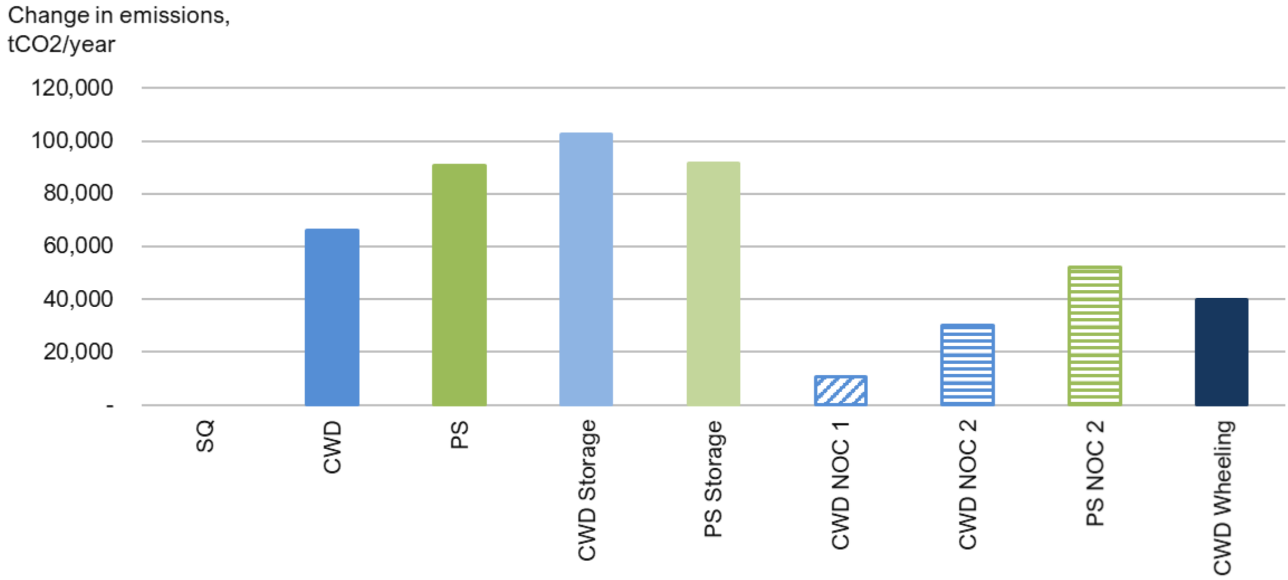
4.3. Impacts on the environment

Environmental impacts may occur as a consequence of the impact that gas tariffs have on electricity generation from gas-fired power stations. Where the tariff structure results in a lower tariff for gas-fired power generators (e.g. under the options which include a NOC), their operational and investment incentives may improve. To the extent that this results in gas-fired generation displacing other types of generation in the electricity market merit order, the overall generation mix, and power generation emissions may be affected as a result.

Where gas-fired power generators displace more carbon-intensive conventional generation (such as coal), we would observe a decrease in emissions. This may occur in the early years within the period where some coal still remains on the system. However, in later years, cheaper gas-fired power generation may lead to higher national or cross-border demand for electricity which could increase GB carbon emissions. We would expect this to be the case following closure of coal plant in the gas years 2026/27 and 2030/31.

We show the average annual impact on carbon emissions in Figure 4.3.

Figure 4.3: Changes in average annual carbon dioxide emissions under each option (2022-31)



This shows that the increase in gas-fired power generation under all options results in an increase in emissions over the study period. However, the impact is relatively small when compared to total emissions from gas-fired power stations under the status quo. The maximum increase in carbon dioxide emissions (observed under the CWD Storage option) is less than 0.2% of total emissions from the GB electricity sector.

We also monetise these changes in emissions based on the short-term traded sector carbon values that BEIS publishes for use in policy appraisal.[75] In NPV terms (2022-31, £18/19), the additional cost of these changes in emissions relative to the status quo ranges from £5 million (under the CWD NOC 1 option) to £47 million (under the CWD Storage option) in the TD scenario using central estimates of the carbon value. The change in emissions under the CWD and PS options represents an additional cost of £31 million and £42 million respectively, in NPV terms (£18/19 prices).

Using BEIS' high case carbon values, we estimate a total range of £8 million to £73 million (NPV, 2022-31, £18/19), with an additional £48 million and £65 million of monetised carbon emissions under the CWD and PS options respectively.

[75] BEIS, April 2019, Updated short-term traded carbon values. These costs steadily rise from £27.4/tCO2e to £80.8/tCO2e over the period we are considering.

We note that these differences in additional carbon costs compared to the status quo should be considered in the context of GB electricity sector emissions over the period, and the level of carbon costs that these would represent. Based on our modelling results, these costs would amount to nearly £25 billion under the status quo (NPV, 2022-31, £18/19, TD scenario). In this context, we consider that the approximately £40 million range (i.e. approximately 0.2% total emissions) observed between the additional costs under each of the options is small.

5. QUALITATIVE ANALYSIS

5.1.1. Impacts of a 'net zero' scenario

In the 2019 FES, National Grid have included a sensitivity on how net zero could potentially be achieved, but they not have not included a fully developed 'net zero' scenario. This sensitivity indicates that greater action across all decarbonisation solutions (electrification, energy efficiency and carbon capture) will be needed than what is assumed in the four core 2019 FES scenarios. National Grid's findings indicate that to meet the 2050 net zero target:

- **Electrification** will need to be higher than in any of the core four scenarios, resulting in much higher peak demand for electricity.
- **Carbon capture, use and storage (CCUS)** will be essential – assumptions about CCUS use will influence gas demand by gas-fired electricity generation.
- **Fundamental changes to natural gas use** – no gas boilers will be used for domestic heating by 2050, implying a complete technology switch.
- **Heating demand** will need to be reduced through substantial improvement in thermal efficiency of GB buildings – thus overall heating demand will be lower.

Given the government's current policy, we consider that meeting the net zero target by 2050 will be a baseline assumption going forwards, but we did not attempt to develop bespoke scenarios for the purpose of our modelling. The main mechanisms through which a net zero scenario could impact upon our analysis are as follows:

- Impacts on gas demand, both volume and peak.
- Impacts on electricity demand, both volume and peak.
- Impacts on the electricity generation mix, particularly relating to CCUS and implications for gas-fired power generation.

Compared to the TD scenario, in a net zero scenario we would anticipate a general trend towards lower gas demand out to 2030, with less electricity generated from gas. This would result in lower demand in total and, all else equal, higher tariffs across all entry and exit points.

Beyond 2030, we would expect gas demand to continue to fall. However, as with the TD scenario, we would also expect gas-fired generation coupled with CCUS to increase towards 2050.

5.1.2. Security of supply

We did not conduct a detailed security of supply analysis against supply or demand shocks for any of the options considered. However, the estimated magnitude of the changes in transmission tariffs under the proposed options is small relative to other features of the wholesale gas market. This suggests that the direct security of supply impact of the options (without considering longer-term impacts on closure and investment) is likely to be limited.

Any security of supply impacts are more likely to result from changes to the supply stack in the medium to long term, if changes in tariffs are material and affect investment and closure decisions in those timescales. Our analysis in Section 0 suggests that the magnitude of changes to tariffs in comparison to other investment and closure decisions means that they are only likely to affect marginal investment and closure cases.

Price stability

However, we have also identified the potential for tariff arrangements to impact on the wholesale gas and electricity price. Though we estimate that these impacts would be small, we observed that this could result in a transfer of surplus from producers to consumers. While still small, this could contribute to erosion of the margins of some sources of supply, possibly affecting investment and closure decisions that may already be marginal.

We identified more significant potential impacts on revenues of gas storage facilities for example. In the longer term, it is possible that this could weaken price security and stability.

5.1.3. Impacts on the capacity market

To the extent that increases in gas transmission tariffs have a significant impact on the net revenues (and missing money) of gas-fired generators, then there may be some impact on the capacity market. Options that increase power generator revenues, whether through a reduction in the wholesale gas price or their transmission tariff would allow gas-fired power generation to become more competitive in the capacity market, which may reduce the capacity market clearing price. The opposite impact may occur if the gas price or power generator exit tariffs increase.

While we did not analyse impacts on the capacity market directly, given the relatively small impact of the transmission tariff relative to other costs for gas-fired power generators, we would expect the impacts on the capacity market to be muted. Of course, individual generators may face different effects depending on their location and their tariff under the status quo. This may impact on bidding strategies of some generators.

5.1.4. Impacts of the capacity surrender rule

UNC0678F is identical to UNC0678E, other than that it includes a 'capacity surrender rule'. This rule allows for holders of entry rights allocated between February and December 2018 to surrender all or part of their capacity agreement in the case that the floating reserve price of that capacity increases by more than 5%.

Analysis within UNC0678F suggests that the total volume of capacity acquired in the QSEC auctions to which the capacity surrender rule applies represents a maximum committed expenditure of just over £41 million over a 16-year period.

The surrender of this capacity would result in an equivalent reduction in the amount of revenue recovered by NGGT, although it is possible that the relevant capacity holders would acquire some level of entry capacity as a replacement to align their capacity bookings with future flows.

Nevertheless, this would result in an impact on entry capacity tariffs to make up for the lost capacity revenue. The amount of revenue lost (a maximum of £41 million) compares to an annual revenue recovery requirement which is estimated at £711 million (£ 2018/19) in 2022/23. Therefore, the impact may be small but not insignificant.

5.1.5. Impacts of more restricted revenue recovery requirement

UNC0678 G/H are identical to UNC0678 E/C, respectively, save for the revenue recovery exclusions proposed. While UNC0678 E/C exclude all storage points from revenue recovery, UNC0678 G/H only exclude existing contracts at storage points.

Under the TD scenario, approximately 55% of entry capacity at storage points is expected to be covered by existing contracts in the year 2022-23, with this proportion gradually falling to 29% in 2030-31. Gas volumes included within existing contracts at storage entry points represent approximately 39% of total volumes covered by existing contracts for the gas year 2022-23. Only one existing contract remains in place to 2030-31, and this is at a storage entry point.

Therefore, a significant proportion of existing contracts would no longer be included within the revenue recovery exclusion under UNC0678 G and H. This would significantly reduce the revenue recovery requirements of NGGT to account for these gas volumes, thus lowering the revenue recovery charge at all entry and exit points. It is worth noting that most of this effect would still be observed under UNC0678 D and E, in which contracts for storage capacity, whether existing or new, are the only contracts excluded from the revenue recovery charge.

Compared to UNC0678 G/H, we identify an increase in volumes of gas excluded from the revenue recovery charge under UNC0678 D/E. This increase is relatively small, given that capacity bookings at storage points make up a small percentage of total bookings. Furthermore, the fact that a substantial proportion of storage capacity bookings are expected to be covered under existing contracts, at least in the near term, limits the impact further.

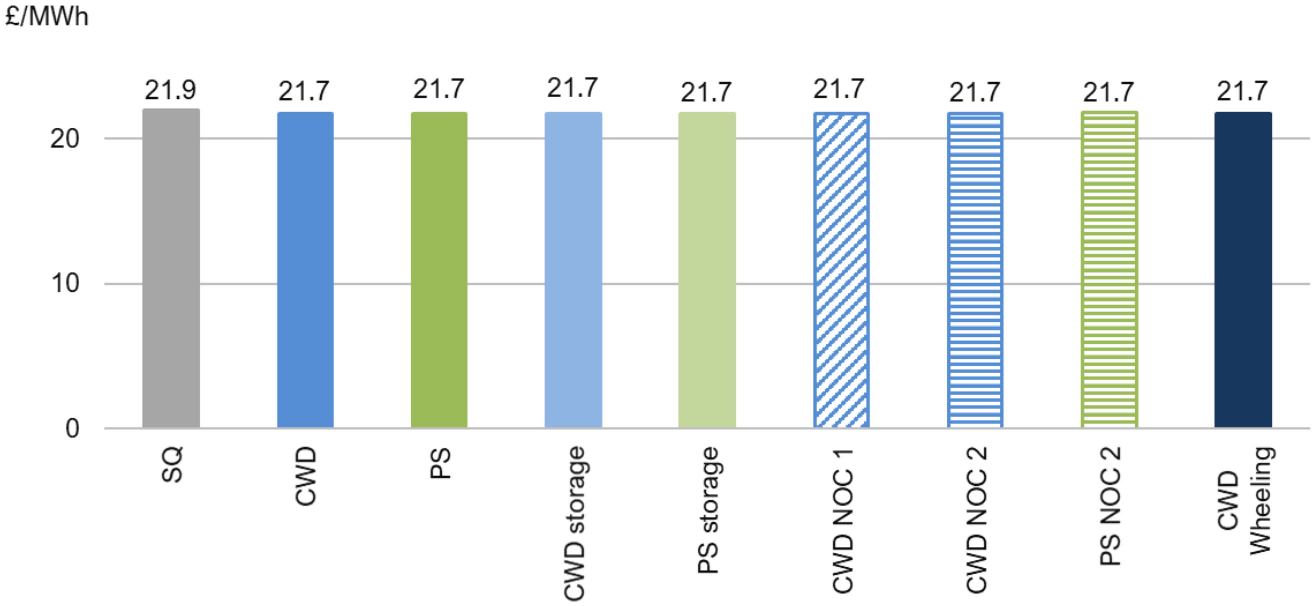
6. DISCUSSION OF RESULTS UNDER STEADY PROGRESSION SENSITIVITY

In this report, we have focused on the results from our TD scenario. The full set of results for all scenarios and gas years is presented in Appendix A. In this section, we provide a short commentary on those areas where there are notable differences in results between the TD scenario and SP sensitivity.

6.1. IMPACTS ON THE WHOLESALE GAS PRICE

One of the main differences between the TD scenario and SP sensitivity is the level of gas demand, both in GB and internationally. Higher gas demand in GB directly results in a higher wholesale gas price. In addition, greater competition for gas globally makes some sources of supply more expensive exacerbating this effect. We present the wholesale gas price across the options under the SP sensitivity in Figure 6.1.

Figure 6.1: Simulated wholesale gas market price impacts under each option (SP, 2030-31, £18/19)



Comparing this to results for the same gas year in the TD scenario (Figure 3.10), we can indeed see that wholesale market prices are higher across the options. The magnitude of the impact on the gas price as a result of the options is similar to that observed for TD. The gas price ranges from £21.67/MWh (under CWD, CWD Storage and CWD NOC Methodology 2) to £21.73/MWh under the PS NOC Methodology 2 option.

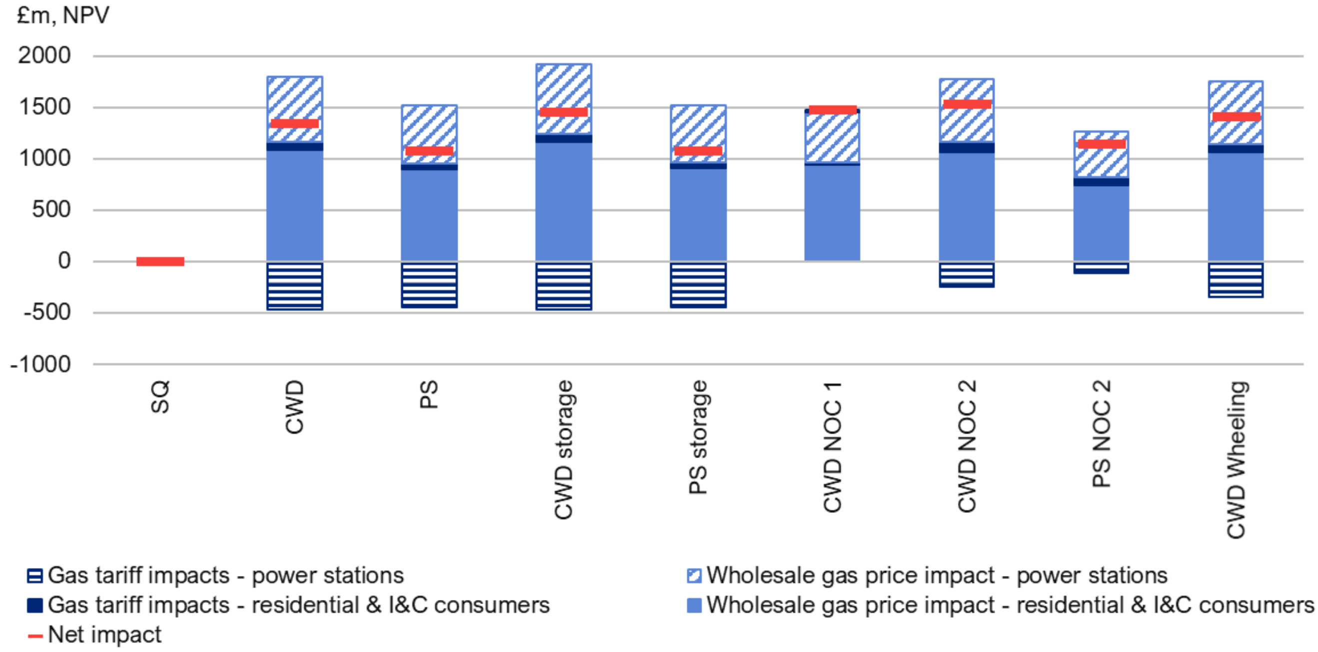
6.2. IMPACTS ON GAS CONSUMER WELFARE

Our analysis of consumer welfare under the TD scenario showed that consumer welfare is greater under those options which do not include a NOC in comparison to those which do. These results are due to the extent of downwards pressure that the tariff arrangements place on the gas, and in turn, electricity price, suggesting that in the case of TD, the additional revenue recovery requirements from the NOC increase the tariff for marginal units of gas on average. We also noted that the impact on the electricity price may depend on the tariff which the marginal unit of gas-fired power generation receives, including any NOC discount where applicable.

Under the SP sensitivity, the impacts of those options which include a NOC relative to those which do not are more balanced. We continue to find that those options without a NOC have slightly higher consumer welfare in general but CWD NOC Methodology 2 and the CWD Wheeling options have similar impacts. After taking into account the impacts on gas-fired power stations resulting from both the wholesale gas price and the tariff, the CWD RPM with

NOC Methodology 2 actually has the highest consumer welfare of all options. This has direct implications for the bill impacts on consumers which are more similar across options.

Figure 6.2: Gas consumer welfare impacts by option (SP, 2022-2031, NPV, discounted to £18/19)



6.3. Impacts on producer revenues

We compared the flows from supply sources under the TD scenario and SP sensitivity in Figure 3.1 and Figure 3.2. One of the most notable differences was the substitution of LNG flows by interconnector entry flows under the SP sensitivity in 2030-31.

The differences in global gas prices and demand dynamics result in a notable difference in the revenue impacts on some producers. In particular, unlike for the TD scenario where we observed an increase in the revenues of bidirectional interconnectors under the options relative to the status quo, we find that revenues decrease relative to the status quo when the SP sensitivity is considered. Global gas demand and supply dynamics mean that beach terminals are relatively more competitive under SP than TD. This dampens the beneficial effects of tariff reform for gas interconnectors given lower levels of substitution of beach terminal flows relative to the status quo. Impacts at Moffat are broadly similar to TD.

Tariff reform under the SP sensitivity actually results in a decrease in interconnector revenues relative to the status quo. Revenues at beach terminals still go down under the modification options but to a lesser extent than was observed for TD.

Figure 6.3: Impacts on revenues of gas interconnectors (NPV, SP, 2022-2031, £2018/19)

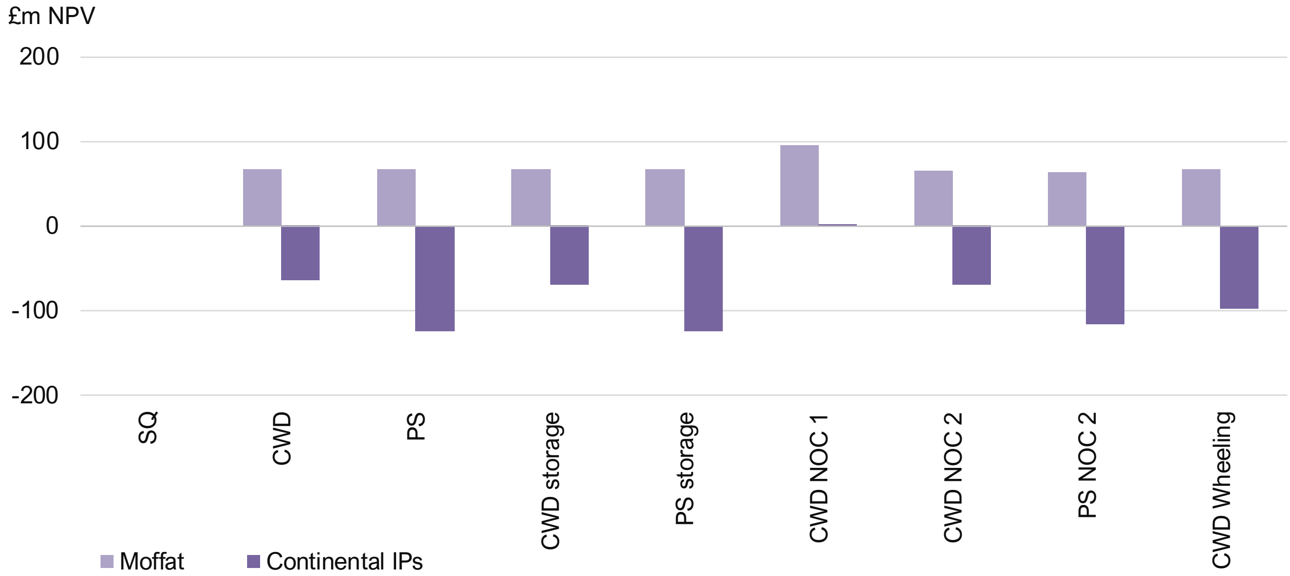
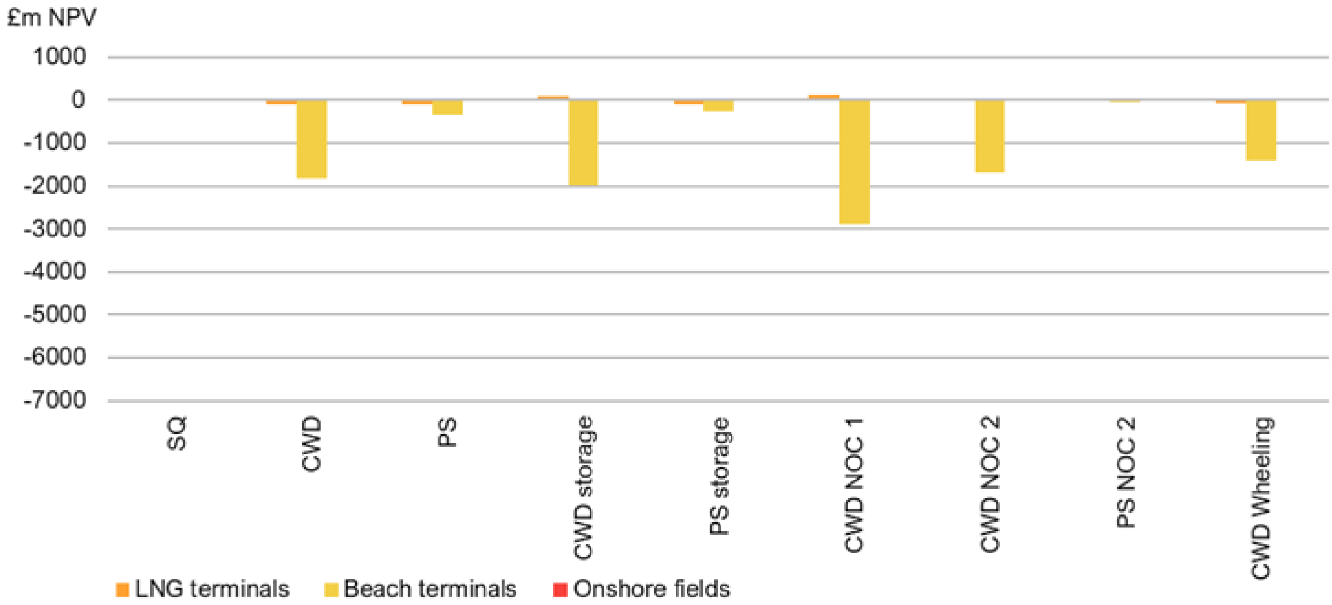


Figure 6.4: Impacts on revenues of producers (NPV, SP, 2022-2031, £2018/19)



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Appendix A DETAILED RESULTS

In this appendix, we present detailed results for all gas years and scenarios. Data tables for these results are included in Appendix B.

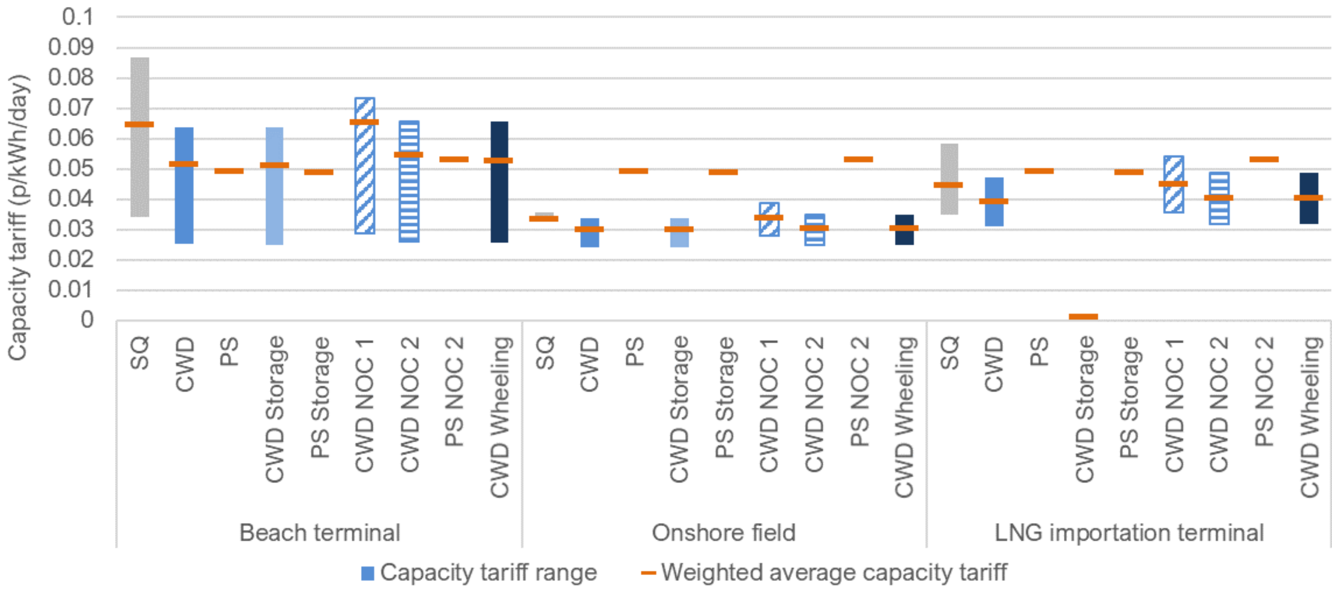
A.1. Steady Progression

A.1.1. Tariff impacts

We note that all tariffs presented for the status quo (SQ), include the commodity charge – i.e. the capacity tariff range and weighted average are 'uplifted' to reflect the commodity element of the transmission services revenue.[76] For GDN exit point tariffs we 'commoditise' the capacity element of the charge to allow it to be added to the commodity charge.[77]

We also note that under the status quo, the commodity tariff is not paid at storage entry or exit points.[78]

Figure A.1: Annual weighted average tariffs at entry points under each option (SP, 2022-23, £18/19)



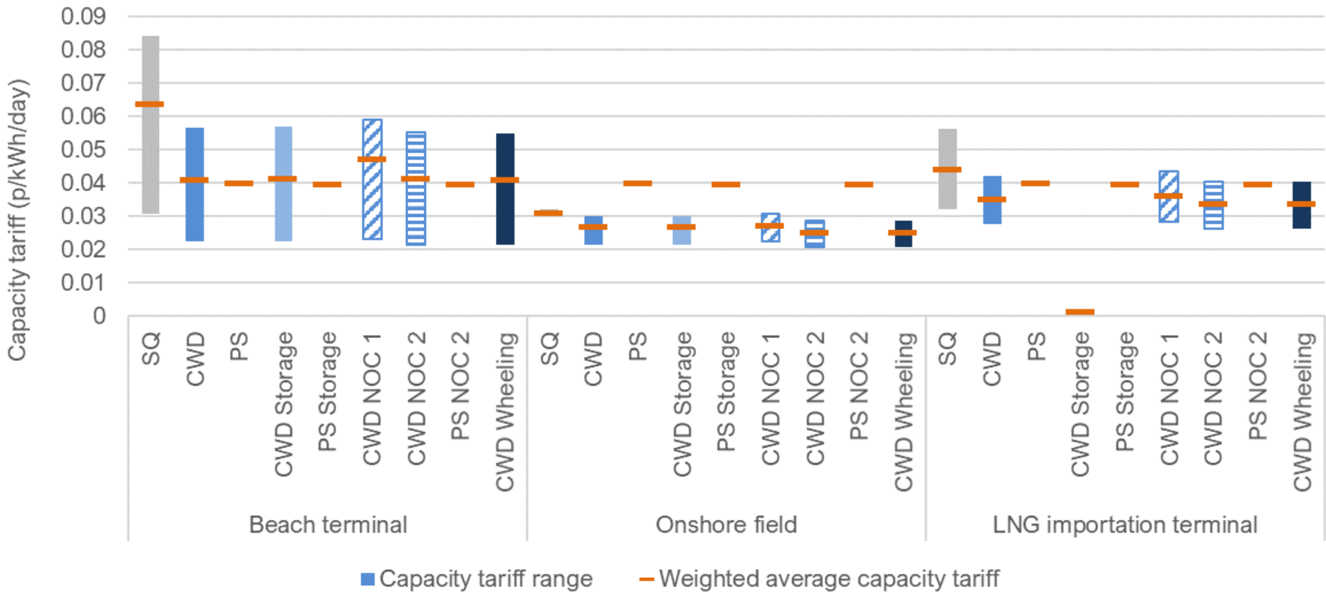
Note: For CWD Storage, the LNG entry tariff reflects the revenue recovery tariff component for existing contracts only (see Table 2.2), as these were sufficient to meet required capacity demand at these entry points for this modelled year under this option.

[76] Given our assumption that bookings are equal to flows for all points other than GDNs, the capacity tariff represents a charge on each unit of gas flowed – i.e. it is effectively 'commoditised'.

[77] Given that GDN bookings are assumed to be much higher than flows, 'commoditising' the capacity charge makes it appear larger. The ratio of GDN bookings to flows (in a given scenario and year) does not vary between tariff options, so this scaling up applies to all options equally.

[78] The commodity tariff is only levied on gas storage facility exit points for 'own use gas' which is a very small proportion of exit flows. We apply an exit commodity tariff of 0.06% to gas storage exit capacity which is consistent with this. This is reflected in the figures that follow.

Figure A.2: Annual weighted average tariffs at entry points under each option (SP, 2026-27, £18/19)



Note: For CWD Storage, the LMG tariff reflects the revenue recovery tariff component for existing contracts only (see Table 2.2), as these were sufficient to meet required capacity demand at these entry points for this modelled year under this option.

Figure A.3: Annual weighted average tariffs at entry points under each option (SP, 2030-31, £18/19)

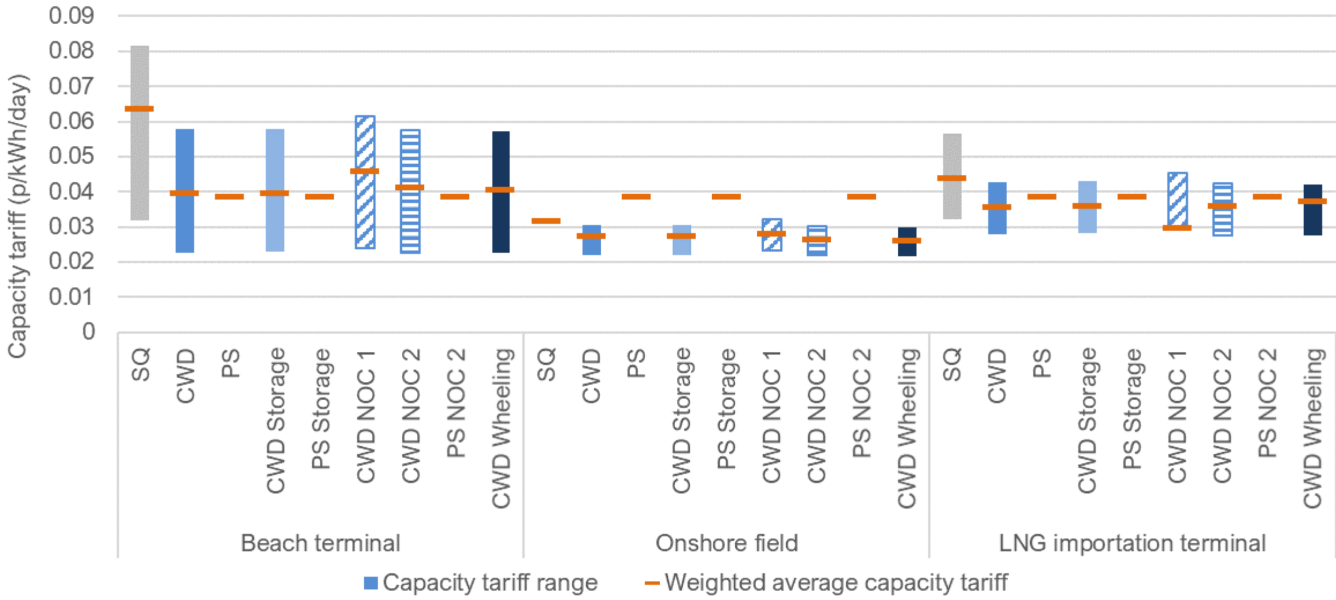


Figure A.4: Annual weighted average tariffs at exit points under each option (SP, 2022-23, £18/19)

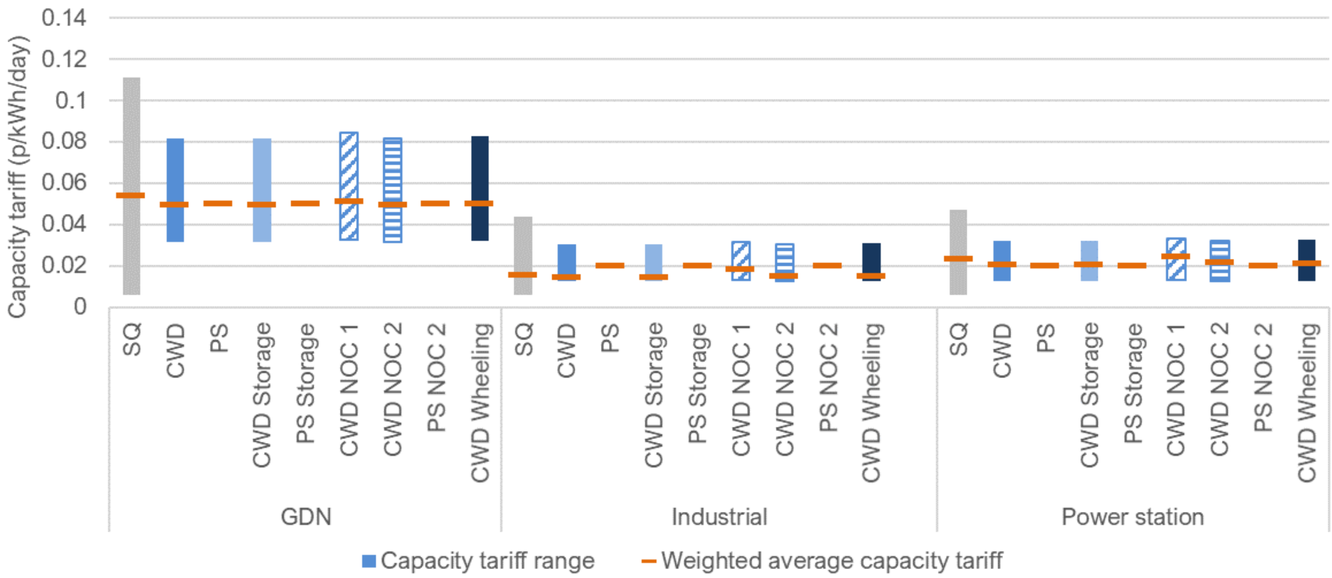


Figure A.5: Annual weighted average tariffs at exit points under each option (SP, 2026-67, £18/19)

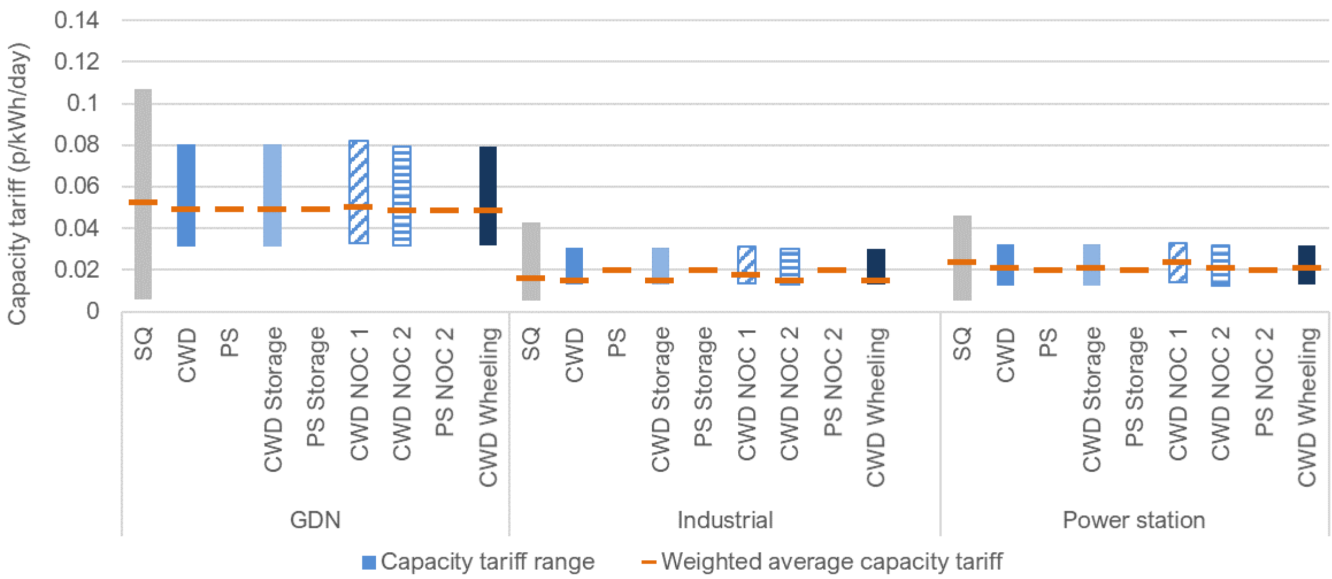


Figure A.6: Annual weighted average tariffs at exit points under each option (SP, 2030-31, £18/19)

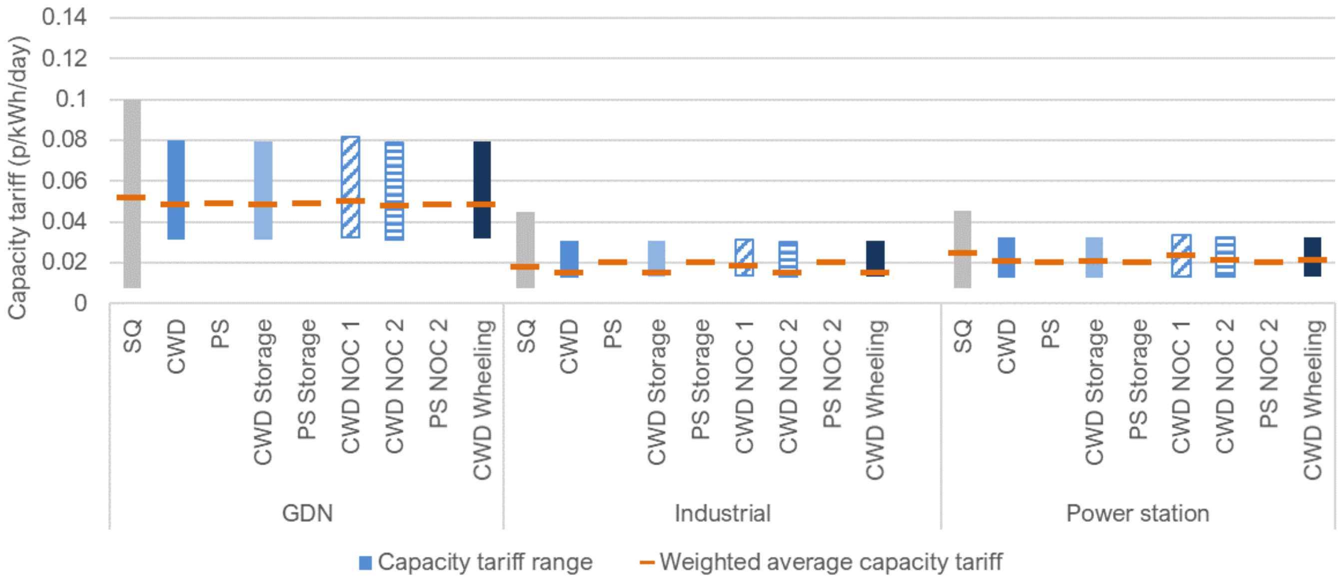


Figure A.7: Annual weighted average capacity tariffs at storage entry and exit points under each option (SP, 2022-23, £18/19)

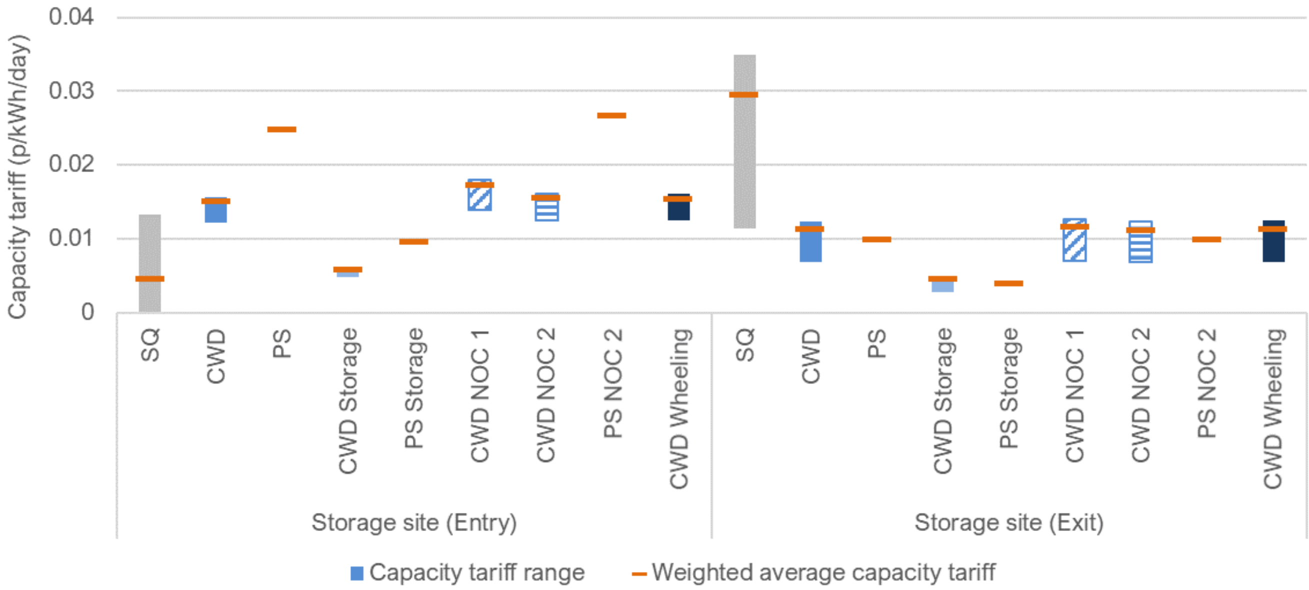


Figure A.8: Annual weighted average capacity tariffs at storage entry and exit points under each option (SP, 2026-27, £18/19)

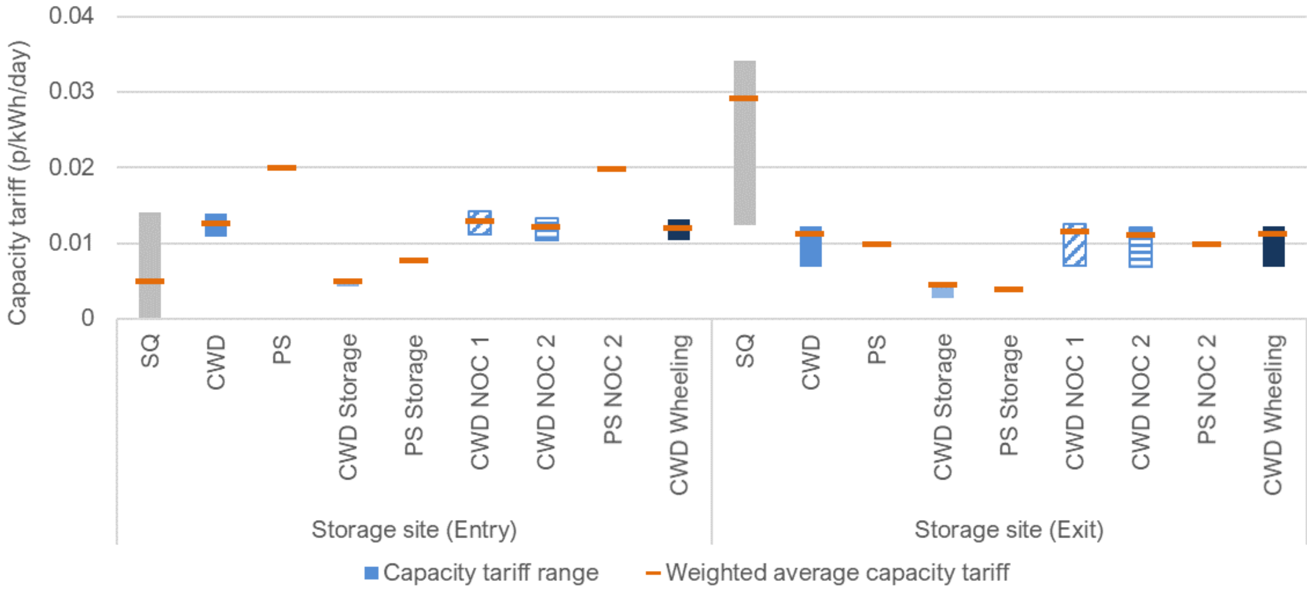


Figure A.9: Annual weighted average capacity tariffs at storage entry and exit points under each option (SP, 2030-31, £18/19)

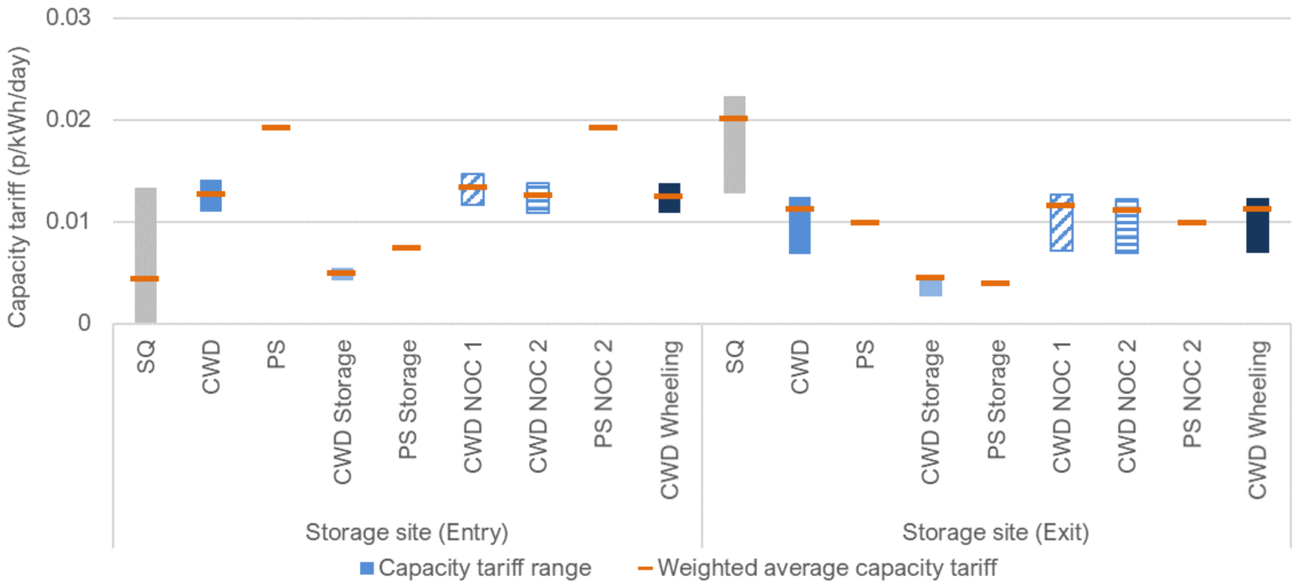


Figure A.10: Annual weighted average capacity tariffs at interconnector entry and exit points under each option (SP, 2022-23, £18/19)

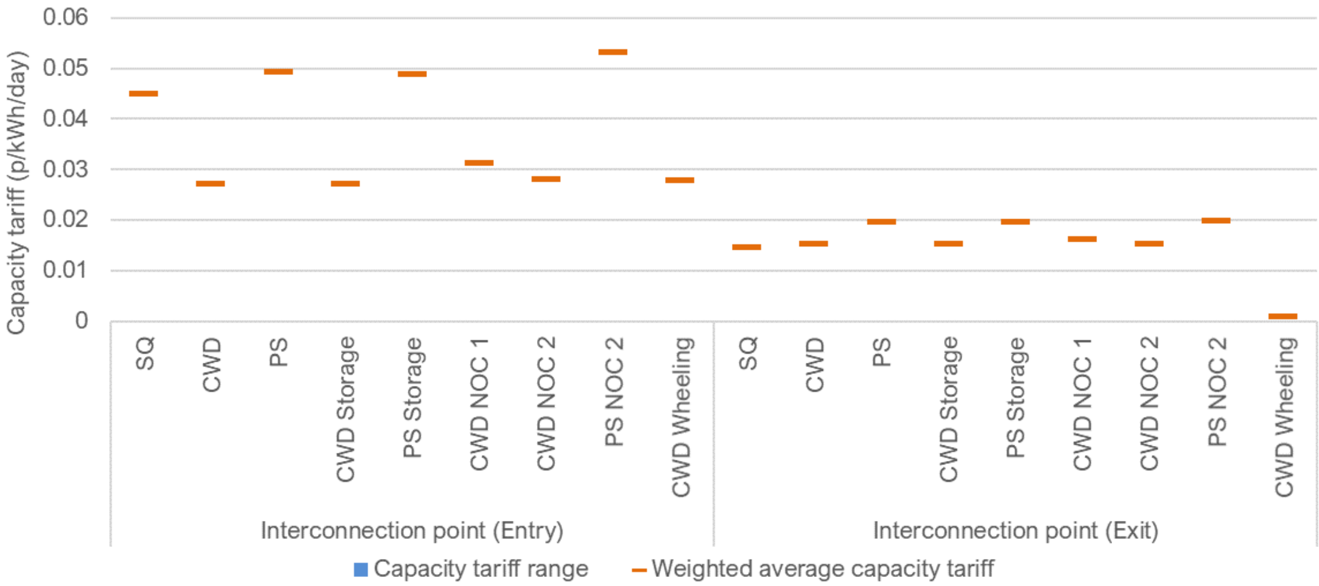


Figure A.11: Annual weighted average capacity tariffs at interconnector entry and exit points under each option (SP, 2026-27, £18/19)

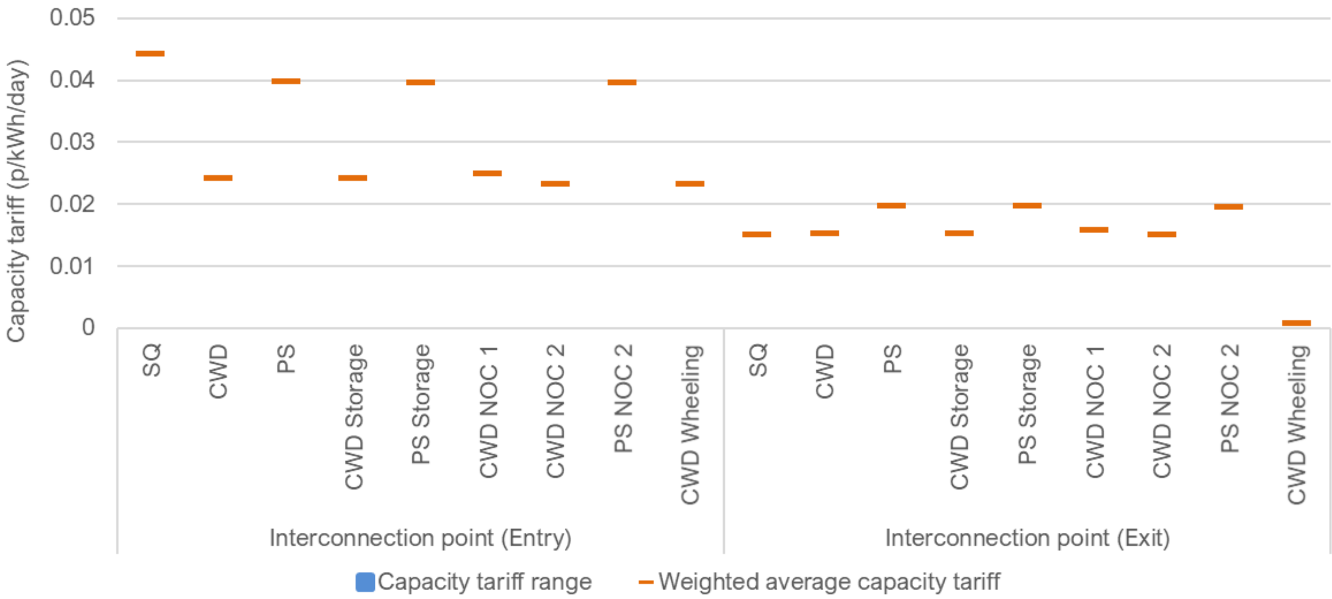
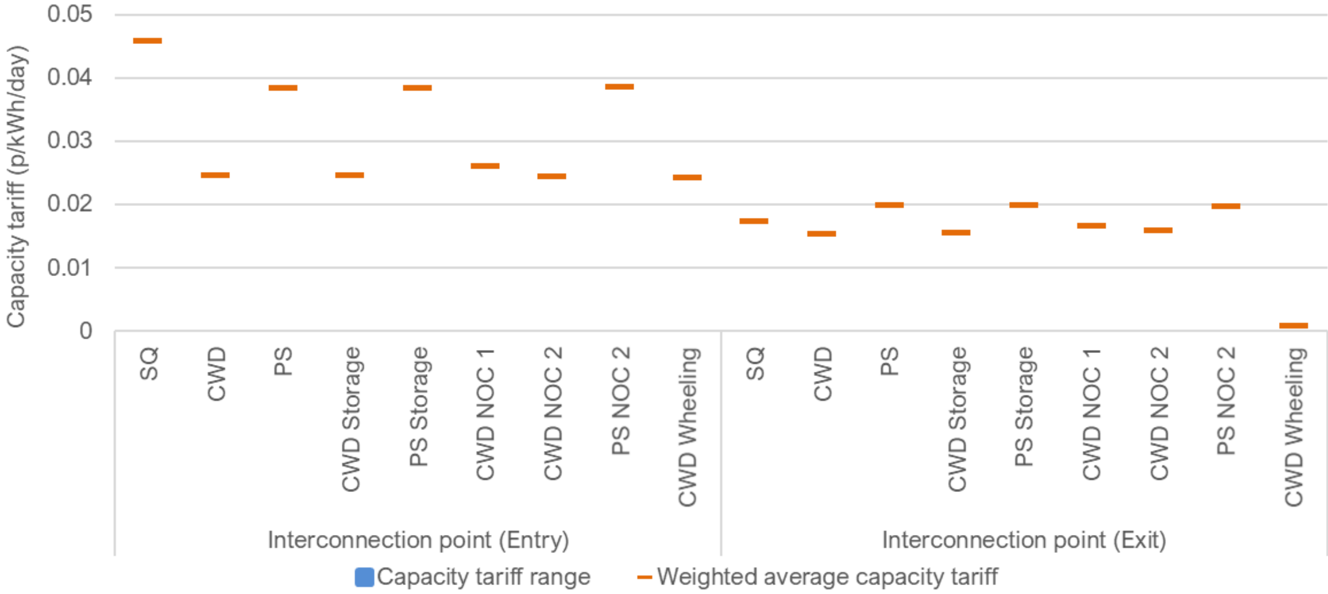


Figure A.12: Annual weighted average capacity tariffs at interconnector entry and exit points under each option (SP, 2030-31, £18/19)



A.1.2. Impacts of a NOC

Table 6.1: Take-up of the NOC (SP, 2030-31)

RPM	Eligible routes (according to method)	Modelled routes	Number of routes that use shorthaul	Total volume of shorthaul flows (TWh/year)	Percentage of modelled flows on shorthaul	Longest distance with use of shorthaul (km)	Simple average route distance (km)
Status quo	All routes	48	31	164.2	41%	274[79]	60.0
CWD, Method 1	All routes	48	30	131.7	33%	164.5	44.7
CWD, Method 2	All routes	48	13	48.1	12%	24.0	4.4
PS, Method 2	All routes	48	18	70.3	17%	43.1	11.3
CWD Wheeling	All routes with a distance of 0 km.	9	6	24.0	46%[80]	1.2	0.3

[79] This represents the largest distance of route that NGGT identify made use of the OCC under existing arrangements in the gas year 2017-18. The modelling suggests that routes of an even greater distance may have commercial benefits in making use of the OCC product. See: National Grid, April 2019, Optional Charge Analysis.

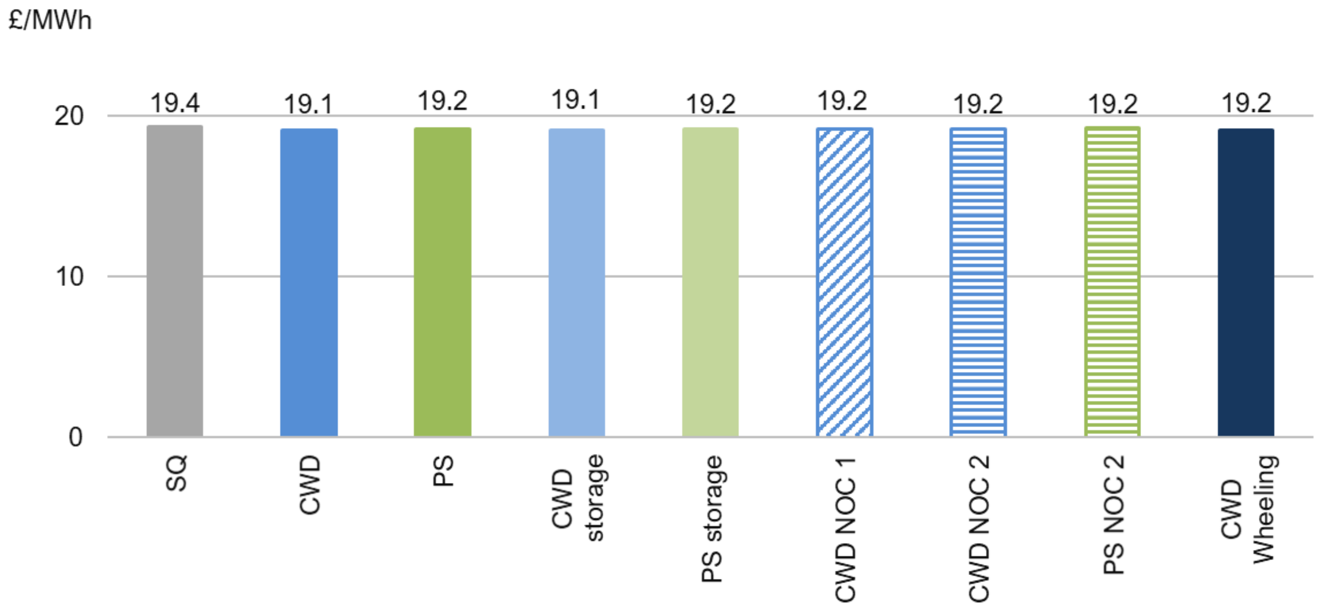
[80] This represents the percentage of the nine modelled routes rather than the 48 that are modelled under other NOC options.

Table 6.2: Revenue recovered and lost from use of the NOC (SP, 2030-31)

Tariff option	Total volume of shorthaul flows (TWh/year)	Amount of revenue from NOC (£18/19m)	Average 'shadow' tariff i.e. revenue recovered per unit of flow (p/kWh) (£18/19)	Lost revenue that would otherwise be recovered from NOC users who paid the standard tariff (£18/19m)[81]
Status quo	164.2	51.1[82]	0.0311	63.5
CWD, Method 1	131.7	15.6	0.0118	60.4
CWD, Method 2	48.1	17.3	0.0360	25.1
PS, Method 2	70.3	28.0	0.0399	39.5
CWD Wheeling	24.0	7.2	0.0298	14.2

A.1.3. Gas and electricity market price impacts

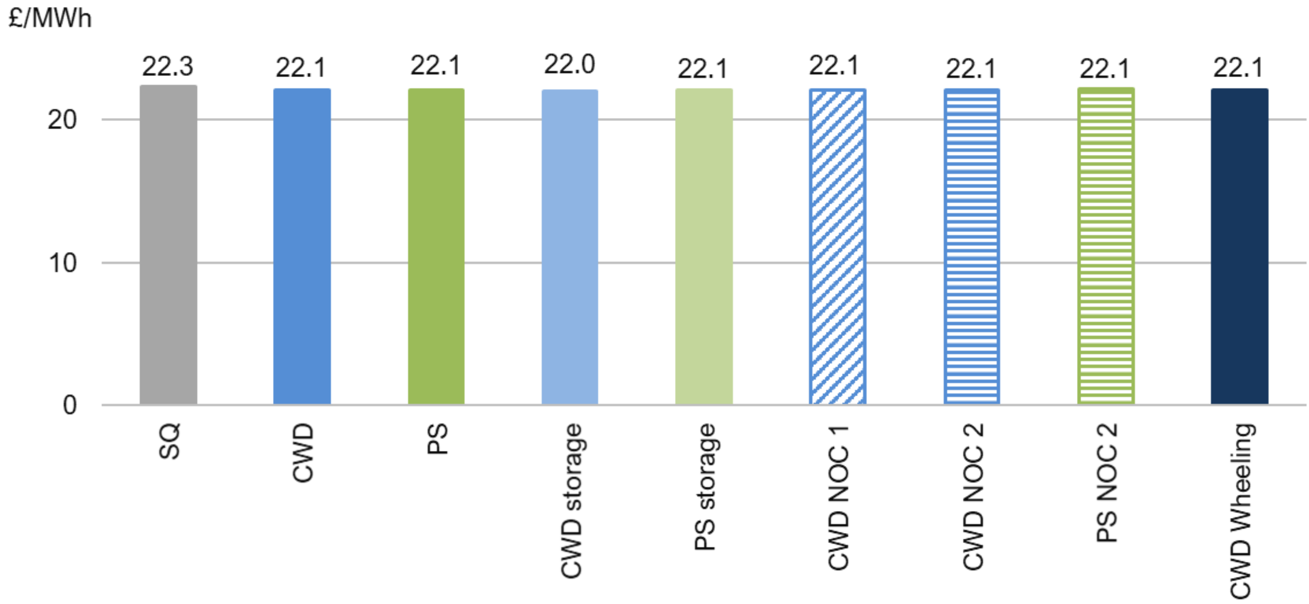
Figure A.13: *Estimated gas market price impacts under each option (SP, 2022-23, £18/19)*



[81] Note that this does not account for the potential for any network user decisions to bypass the NTS.

[82] Note that under the status quo, this figure includes both capacity and OCC revenue from users that take up the OCC. This has no impact on the lost revenue, which continued to represent what would have been recovered if OCC users were liable for the standard entry and exit commodity tariffs.

Figure A.14: *Estimated gas market price impacts under each option (SP, 2026-27, £18/19)*



See Figure 6.1 for the estimated gas market price impacts under each option for SP, 2030-31.

Figure A.15: Simulated wholesale electricity prices by option (SP, 2022-23, £18/19)

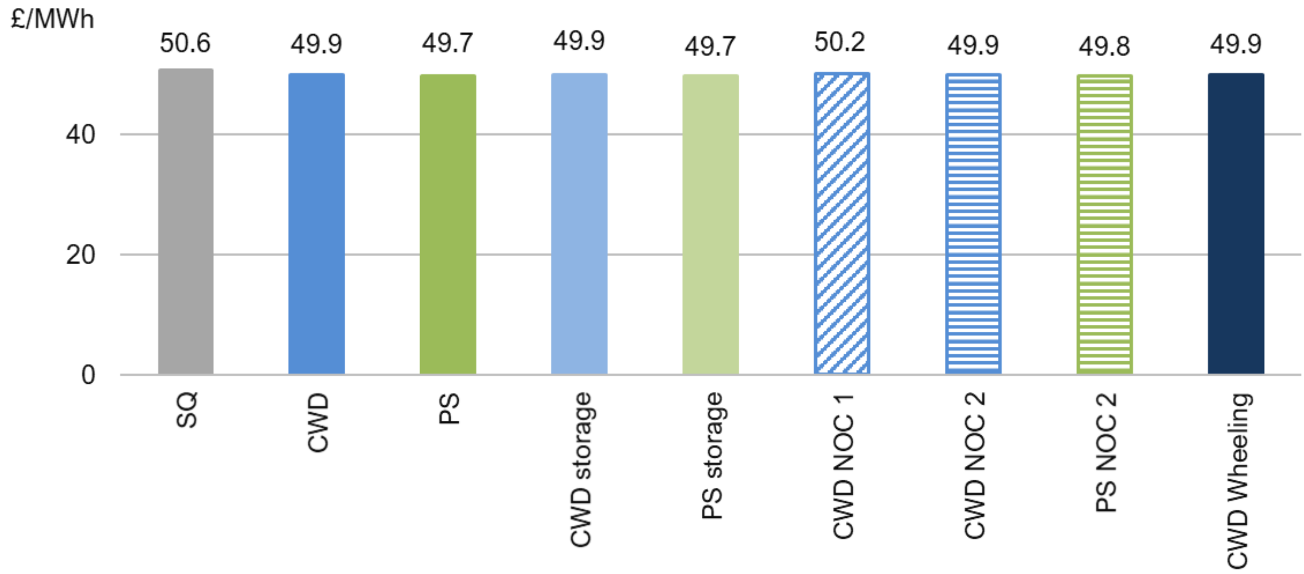


Figure A.16: Simulated wholesale electricity prices by option (SP, 2026-27, £18/19)

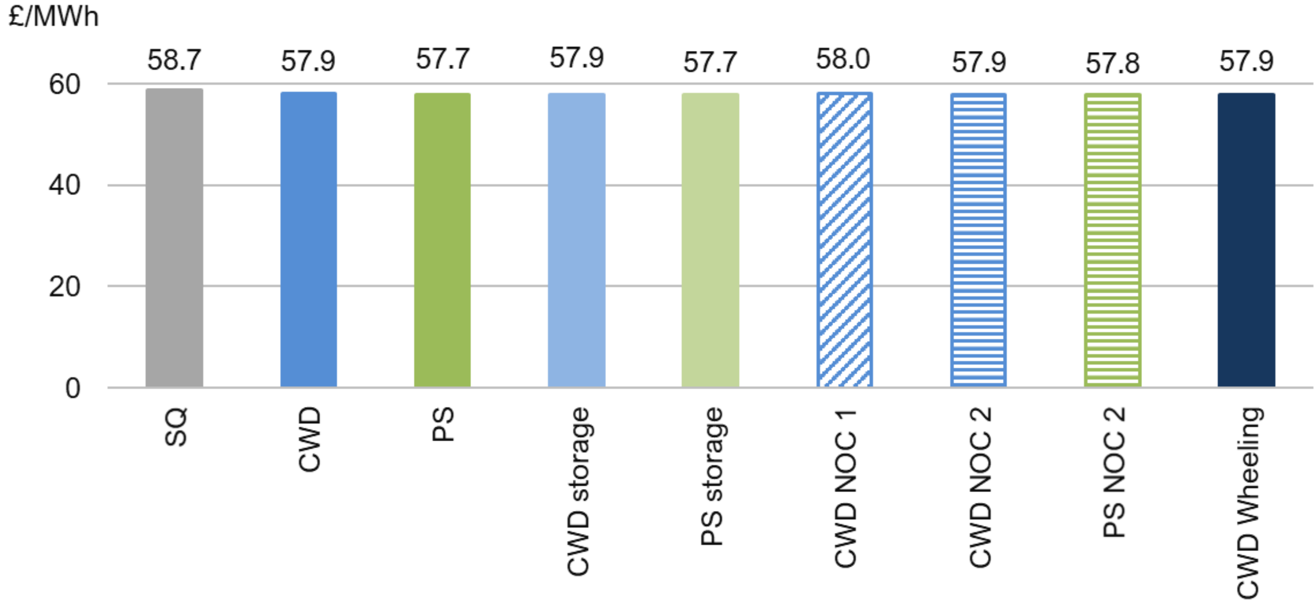
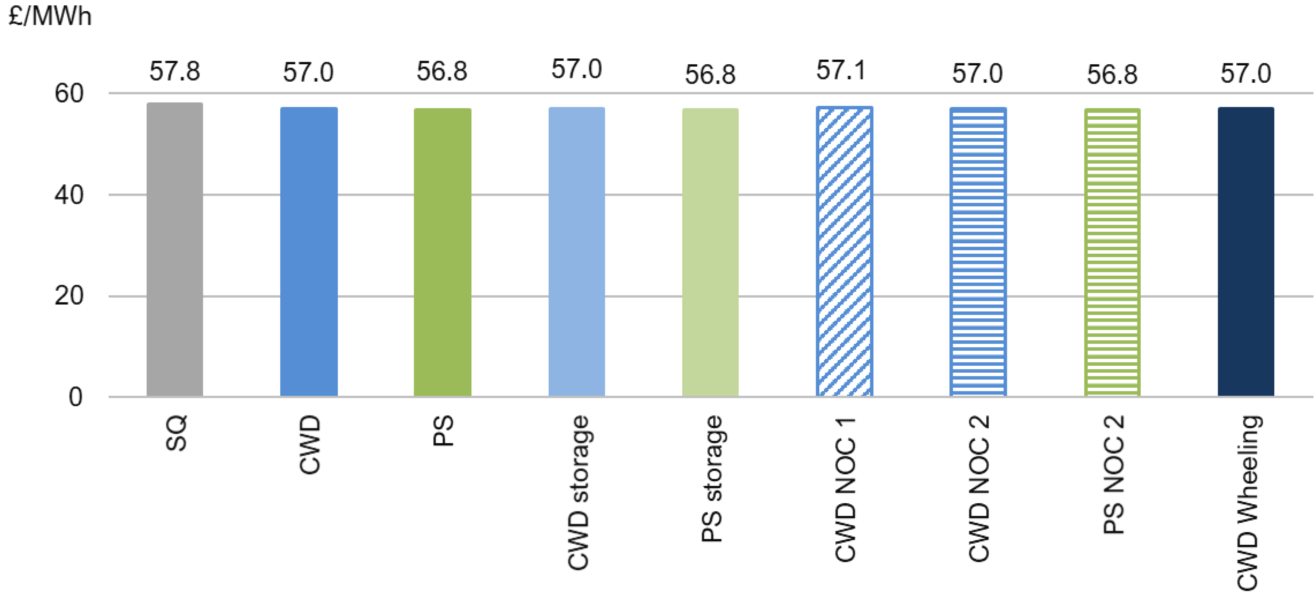


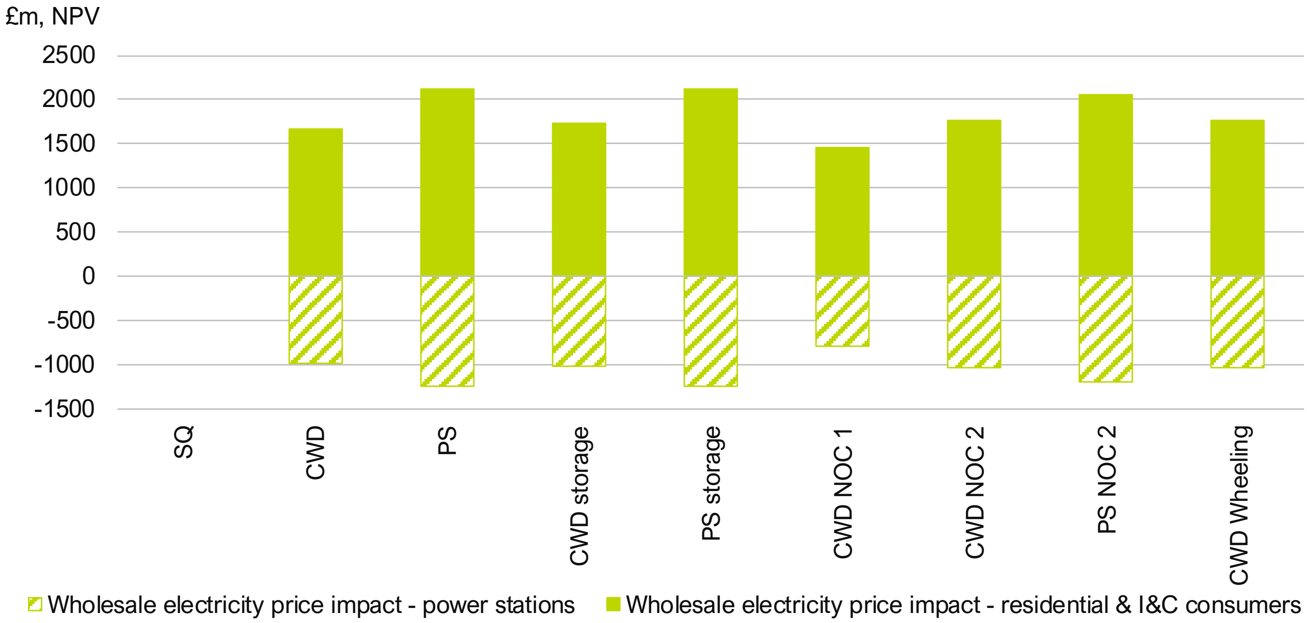
Figure A.17: Simulated wholesale electricity prices by option (SP, 2030-31, £18/19)



A.1.4. Consumer welfare

See Figure 6.2 for gas consumer welfare impacts by option (SP, 2022-2031, NPV, discounted to £18/19).

Figure A.18: Electricity market welfare impacts by option (SP, 2022-2031, NPV, discounted to £18/19)



A.1.5. Bill impacts

Figure A.19: Estimated bill impact for median consumption domestic gas consumers (SP, 2022-23, £18/19)

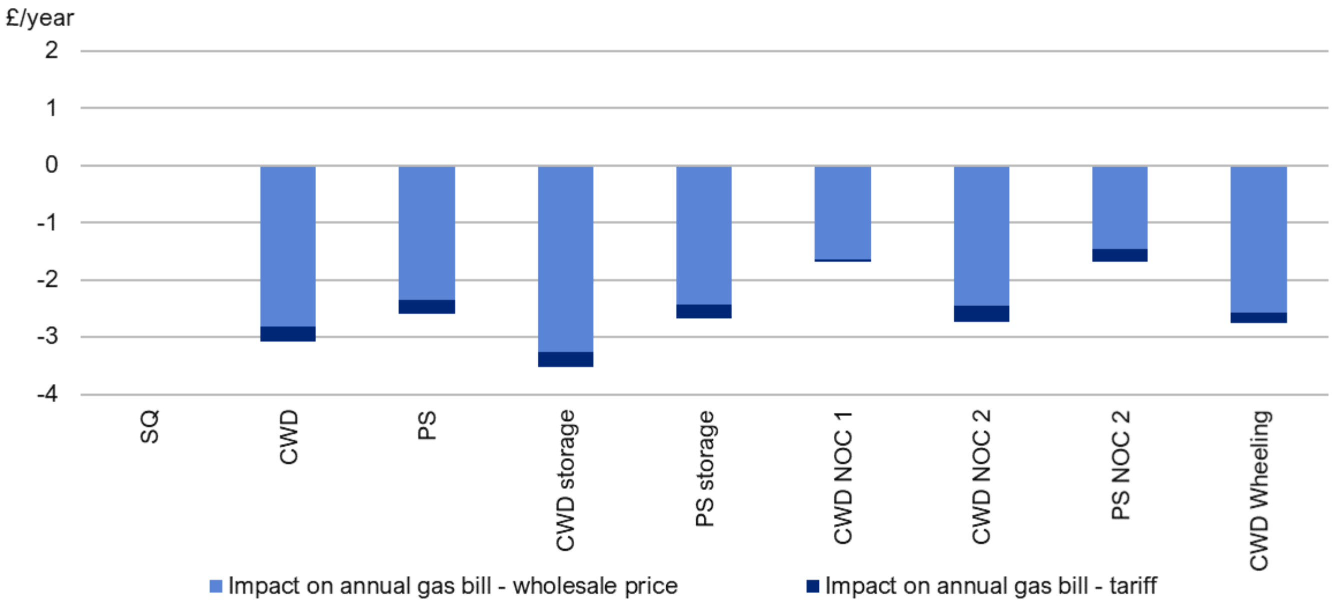


Figure A.20: Estimated bill impact for median consumption domestic gas consumers (SP, 2026-27, £18/19)

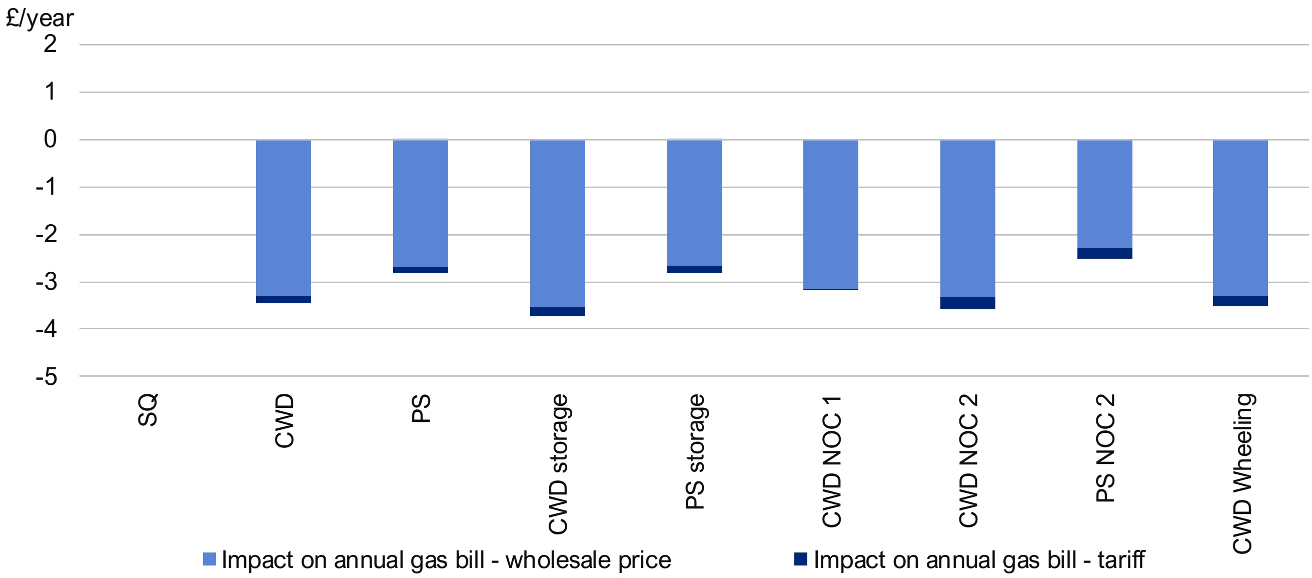


Figure A.21: Estimated bill impact for median consumption domestic gas consumers (SP, 2030-31, £18/19)

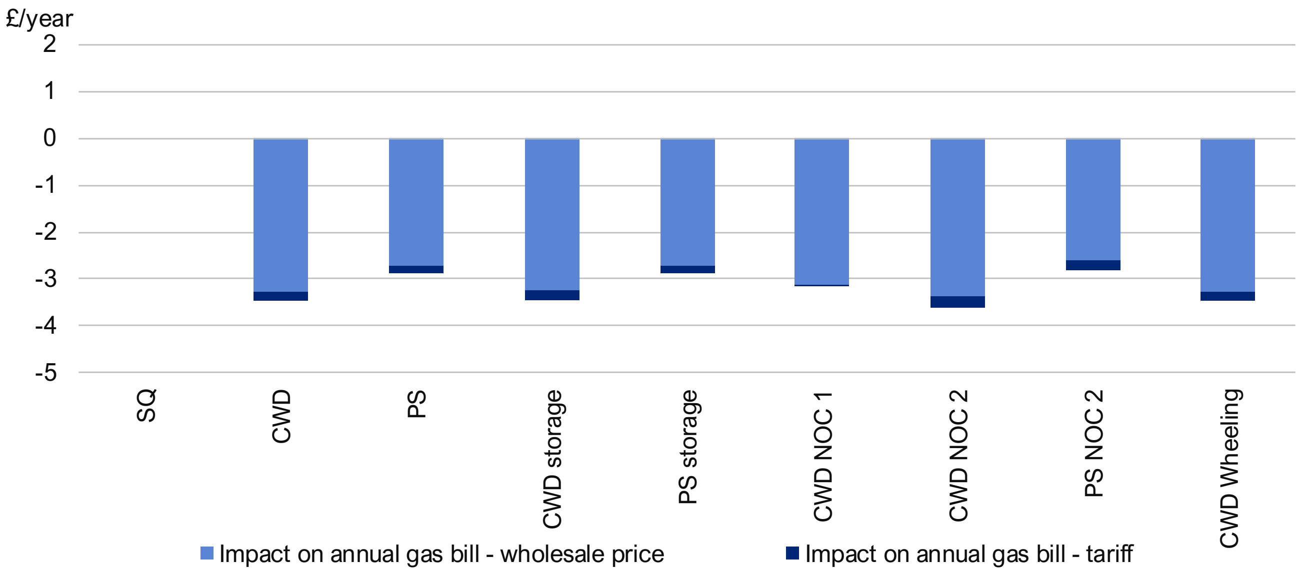


Figure A.22: Estimated bill impact (gas only) for the median non-domestic consumer connected to the LDZ (SP, 2022-23, £18/19)

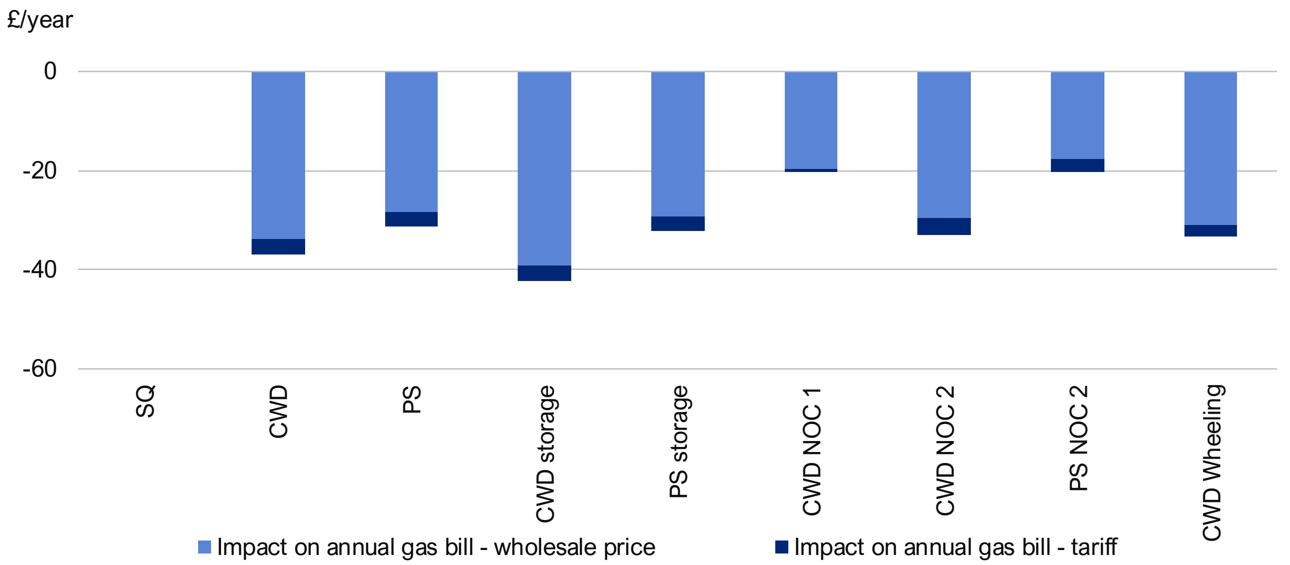


Figure A.23: Estimated bill impact (gas only) for the median non-domestic consumer connected to the LDZ (SP, 2026-27, £18/19)

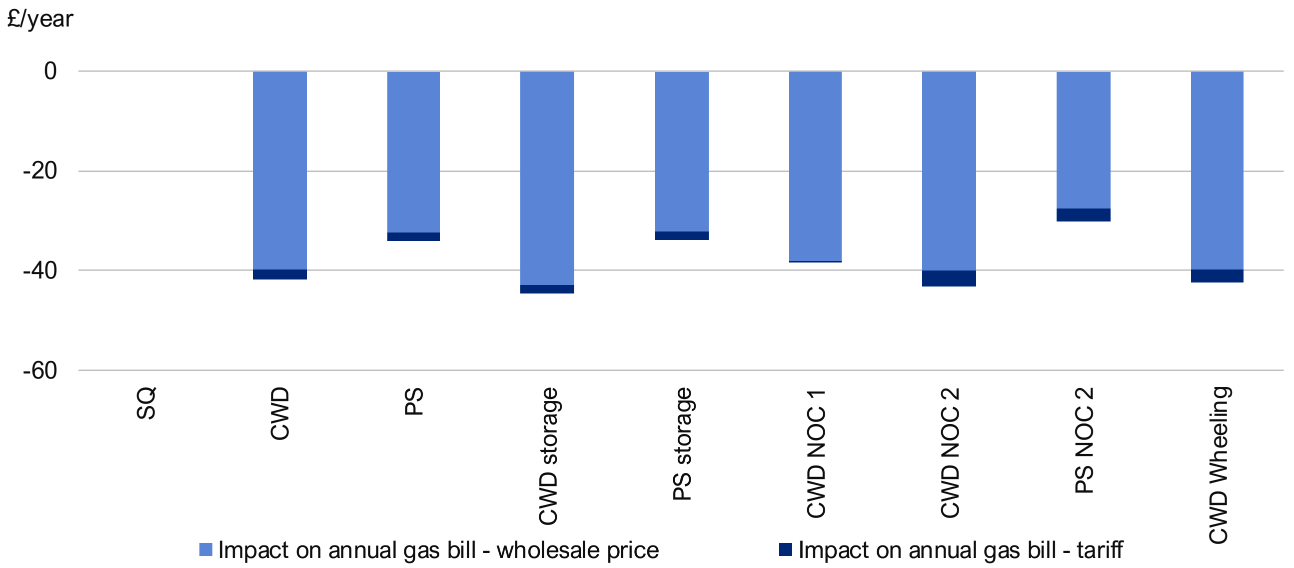


Figure A.24: Estimated bill impact (gas only) for the median non-domestic consumer connected to the LDZ (SP, 2030-31, £18/19)

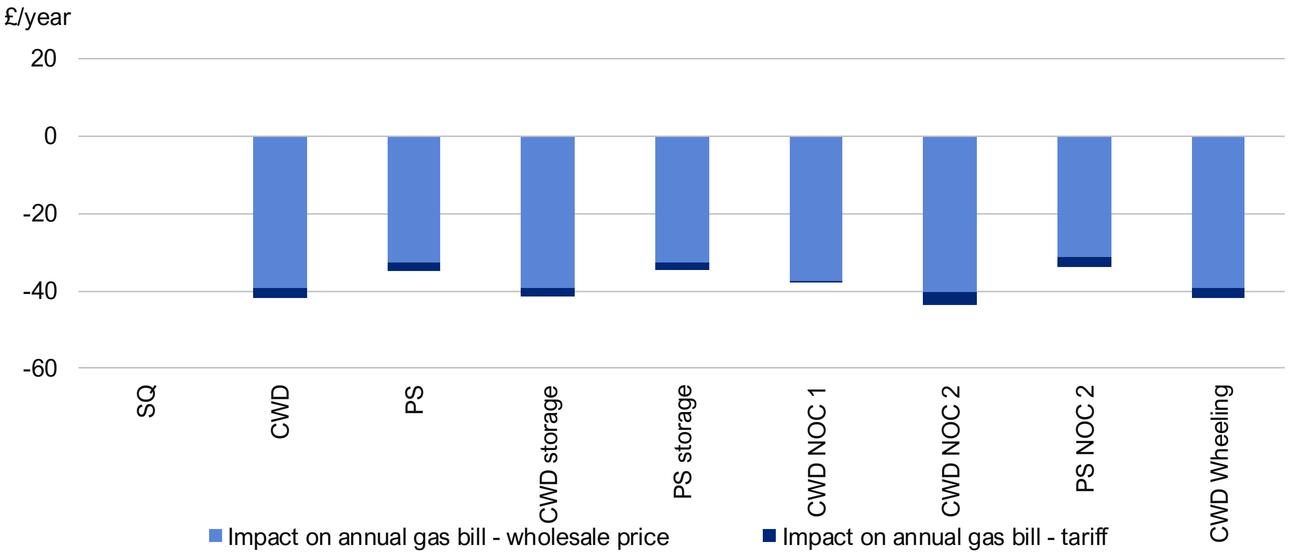


Figure A.25: Estimated bill impact (gas only) for the median non-domestic consumer connected to the NTS (SP, 2022-23, £18/19)

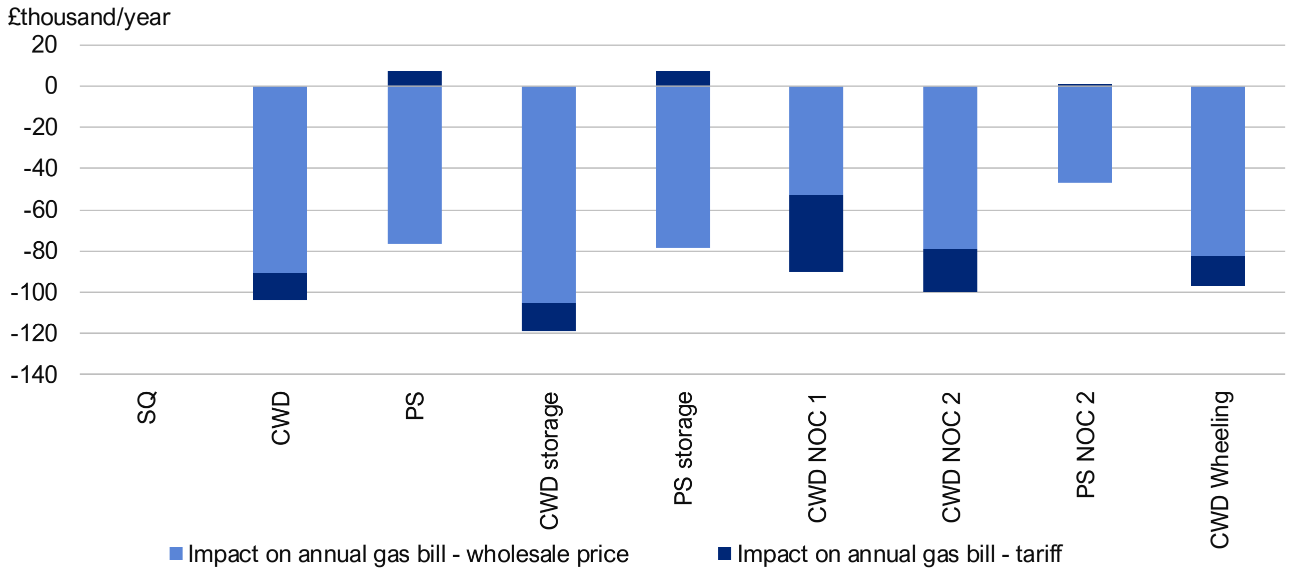


Figure A.26: Estimated bill impact (gas only) for the median non-domestic consumer connected to the NTS (SP, 2026-27, £18/19)

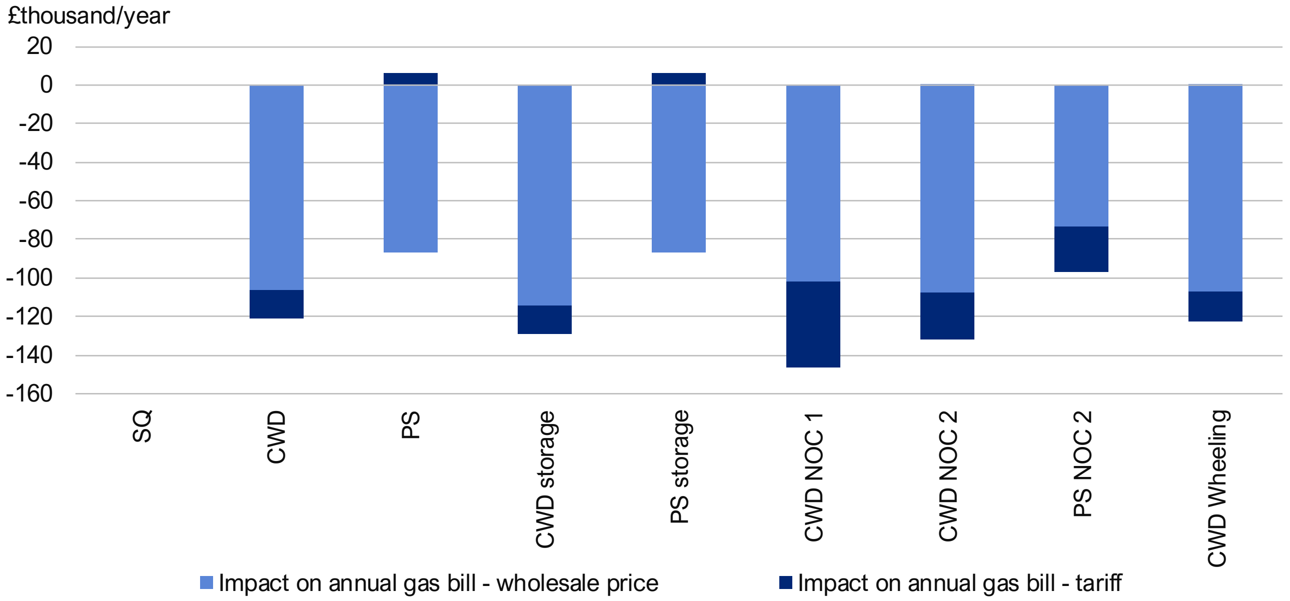


Figure A.27: Estimated bill impact (gas only) for the median non-domestic consumer connected to the NTS (SP, 2030-31, £18/19)

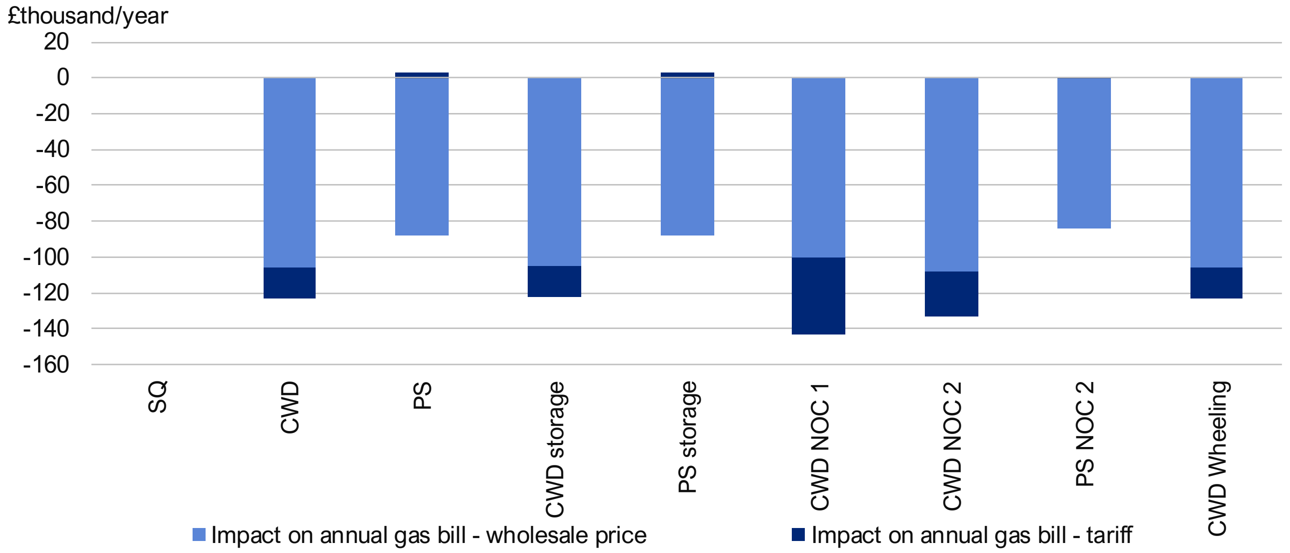


Figure A.28: Estimated bill impact for median consumption domestic electricity consumers (SP, 2030-31 £18/19)

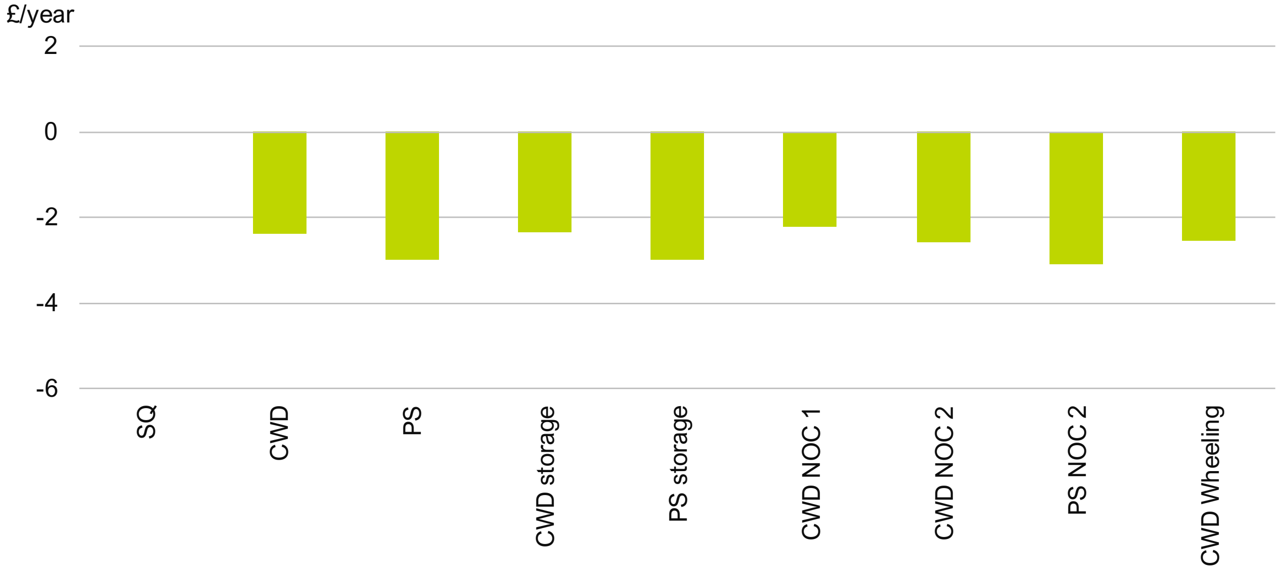


Figure A.29: Estimated bill impact for the most fuel poor quintile domestic electricity consumers (SP, 2030-31, £18/19)

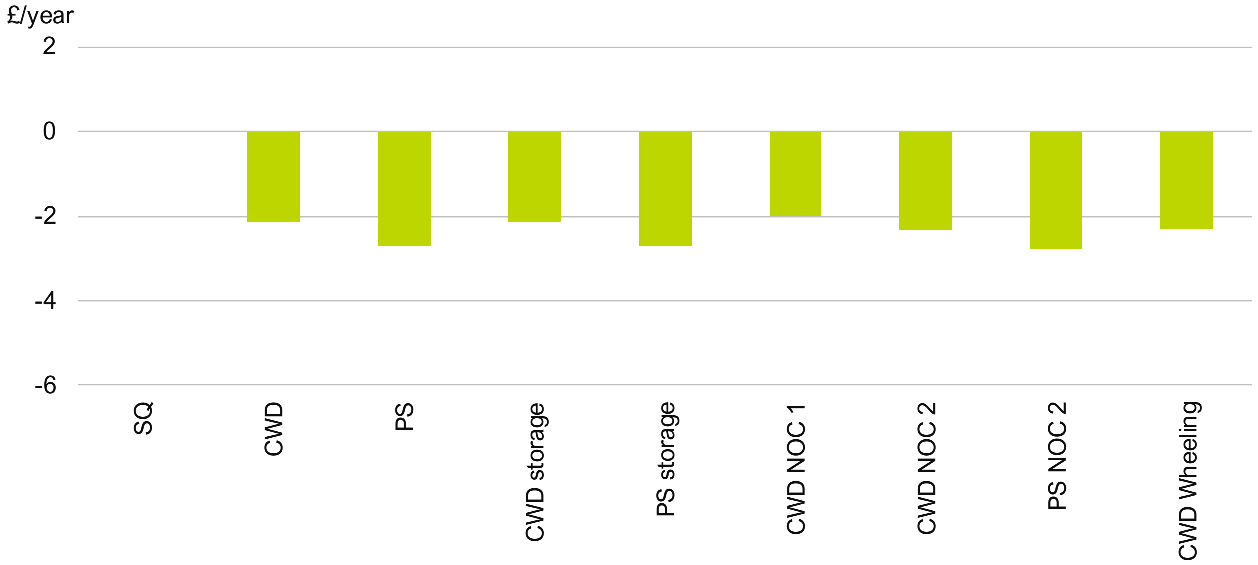
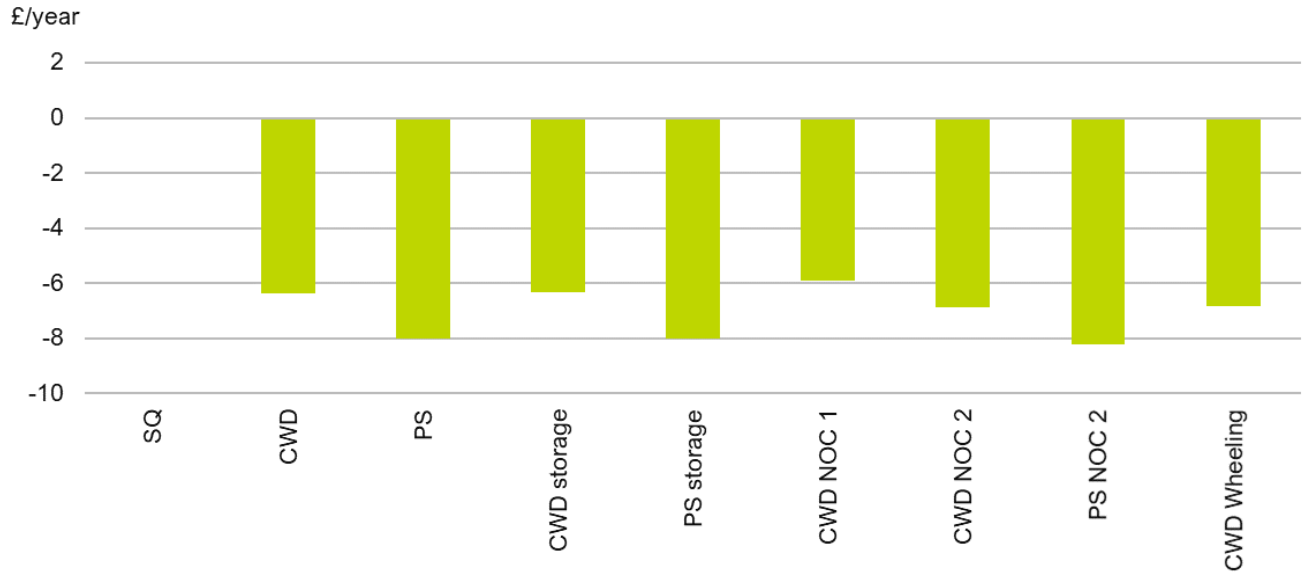
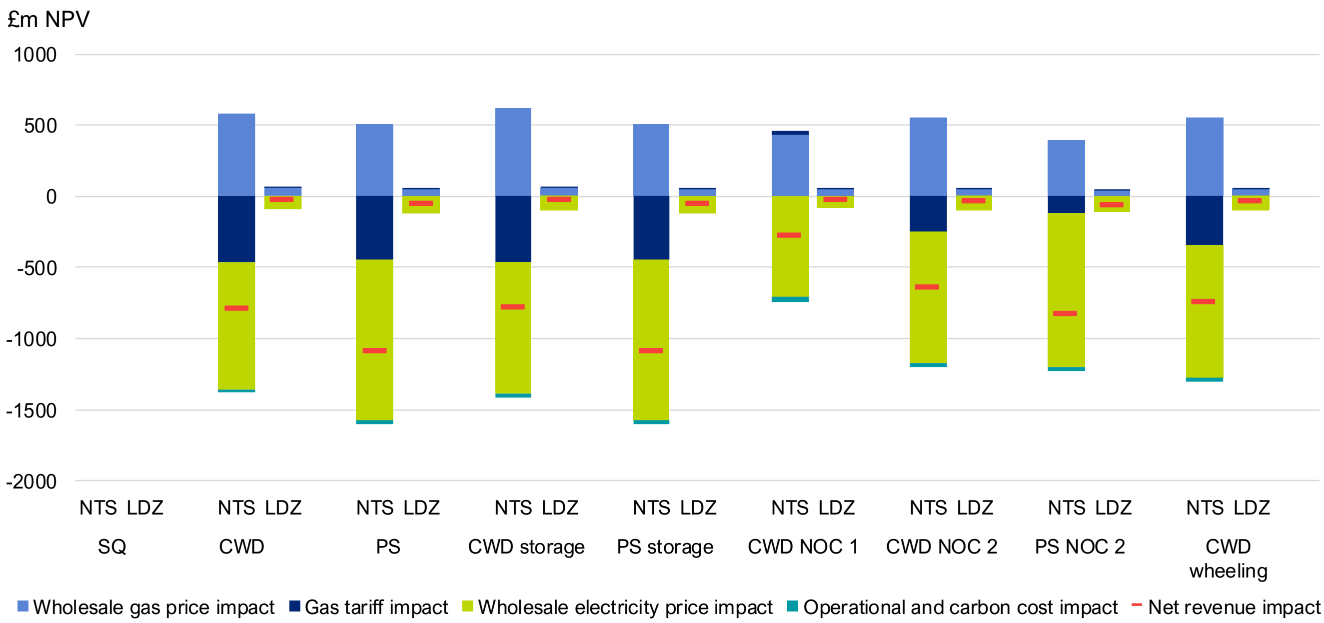


Figure A.30: Estimated bill impact for median consumption non-domestic electricity consumers (SP, 2030-31 £18/19)



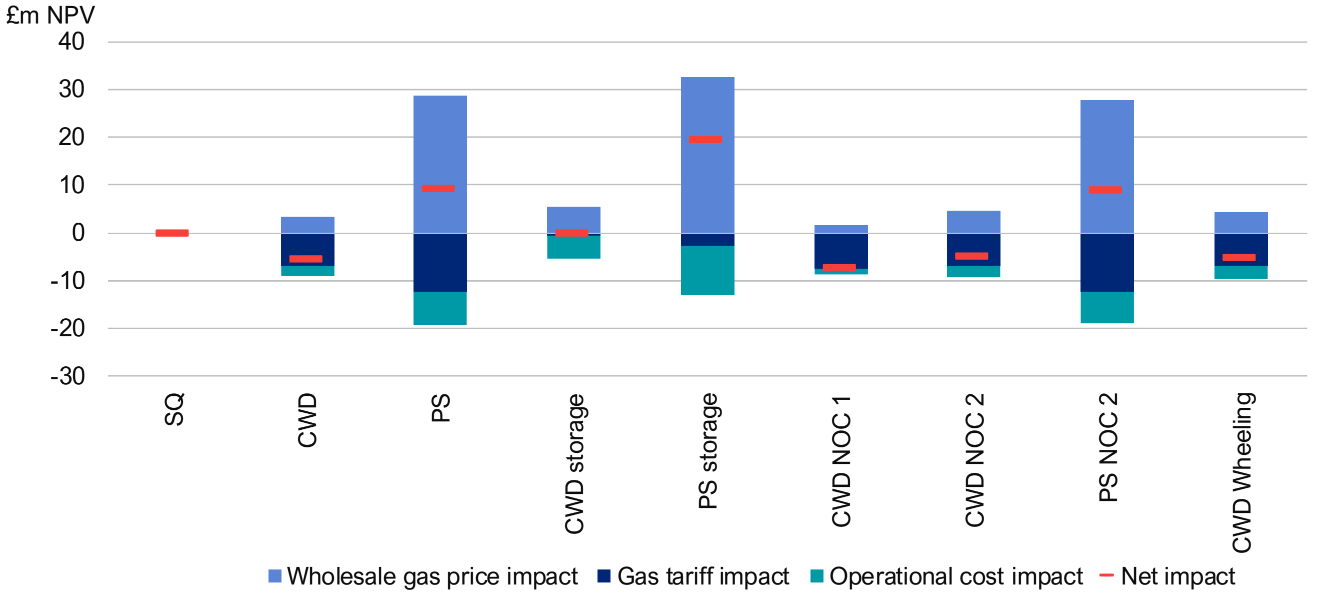
A.1.6. Impacts on power stations and producer revenues

Figure A.31: Impacts on revenues of GB gas-fired power stations (SP, 2022-2031, NPV, discounted to £18/19)



See Figure 7.4 for impacts on revenues of gas interconnectors (NPV, SP, 2022-2031, £2018/19), and Figure 6.4 for impacts on revenues of LNG terminals, beach terminals and onshore fields (SP, NPV, 2022-2031, £2018/19).

Figure A.32: Impacts on total revenues of collective GB gas storage facilities (NPV, 2022-2031, £2018/19)



A.1.7. Bypass analysis

Table A.33: Indicative number of additional routes and flow volumes the present a risk of bypass assuming a five-year payback time relative to the status quo (SP, 2030-31)

Tariff option	Number of routes additional to that observed in the status quo that present a credible risk of bypass[83]	Modelled flows additional to that observed in the status quo that present a credible bypass risk (TWh/year)
CWD	2	13.7
PS	3	29.5
CWD Storage	2	13.7
PS Storage	3	29.5
CWD NOC Method 1	0	0.0
CWD NOC Method 2	0	0.0
PS NOC Method 2	0	0.0
CWD Wheeling	1	8.4

[83] There is a total of 48 routes that made use of the OCC in the gas year 2017-18. These are the routes that we have modelled within the bypass modelling.

Table A.34: Indicative revenue that could be lost due to bypass (SP, 2030-31)

Tariff option	Potential lost transmission revenue if all additional credible bypass routes choose to bypass the NTS (SP, 2030-31, £m 18/19)
CWD	38.4
PS	44.2
CWD Storage	38.4
PS Storage	44.3
CWD NOC Method 1	0.0
CWD NOC Method 2	0.0
PS NOC Method 2	0.0
CWD Wheeling	16.9

Figure A.35: Annual lost revenue by providing the NOC to routes that do not present a risk of profitable bypass of the NTS (SP, 2030-31, £18-19, assuming required payback time of five years)

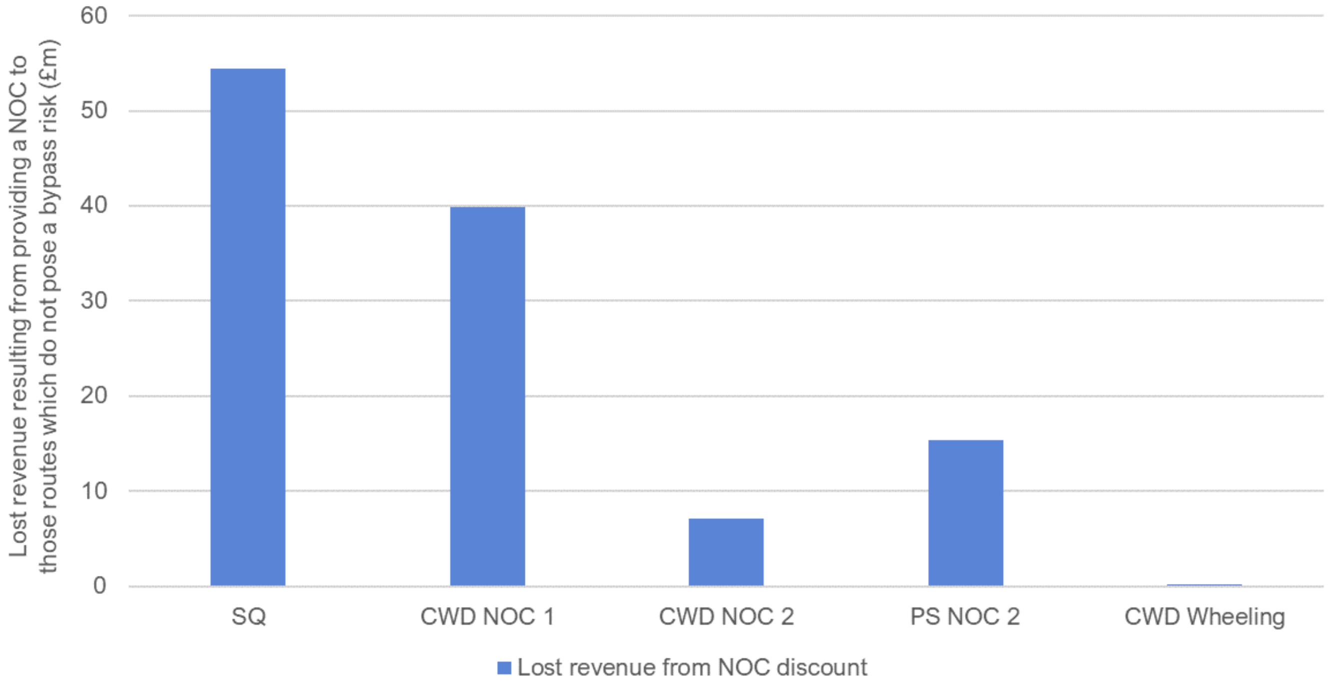
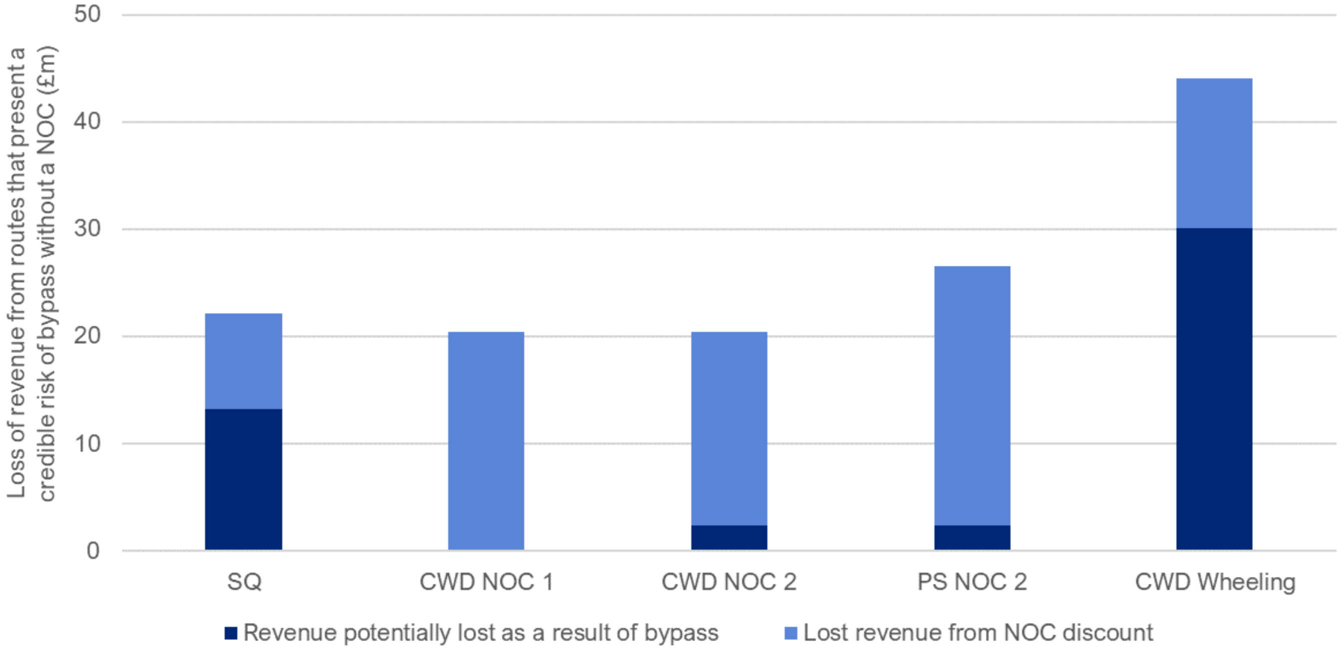


Figure A.36: Annual lost revenue from those routes that present a credible bypass risk in the absence of the NOC (dark blue = revenue lost as a result of bypass, light blue = revenue lost as a result of the NOC discount, SP, 2030-31, £18-19)



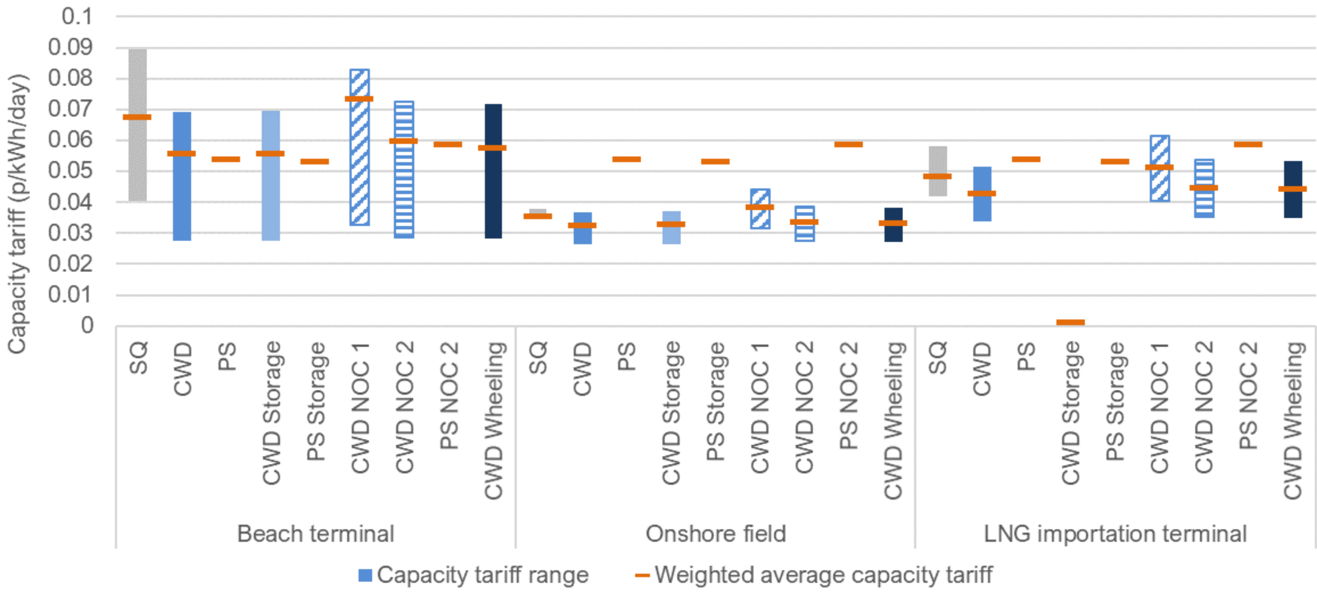
A.2. Two degrees

A.2.1. Tariff impacts

We note that all tariffs presented for the status quo (SQ), include the commodity charge – i.e. the capacity tariff range and weighted average are 'uplifted' to reflect the commodity element of the transmission services revenue.[84] For GDN exit point tariffs we 'commoditise' the capacity element of the charge to allow it to be added to the commodity charge.[85]

We also note that under the status quo, the commodity tariff is not paid at storage entry or exit points.[86]

Figure A.37: Annual weighted average tariffs at entry points under each option (TD, 2022-23, £18/19)



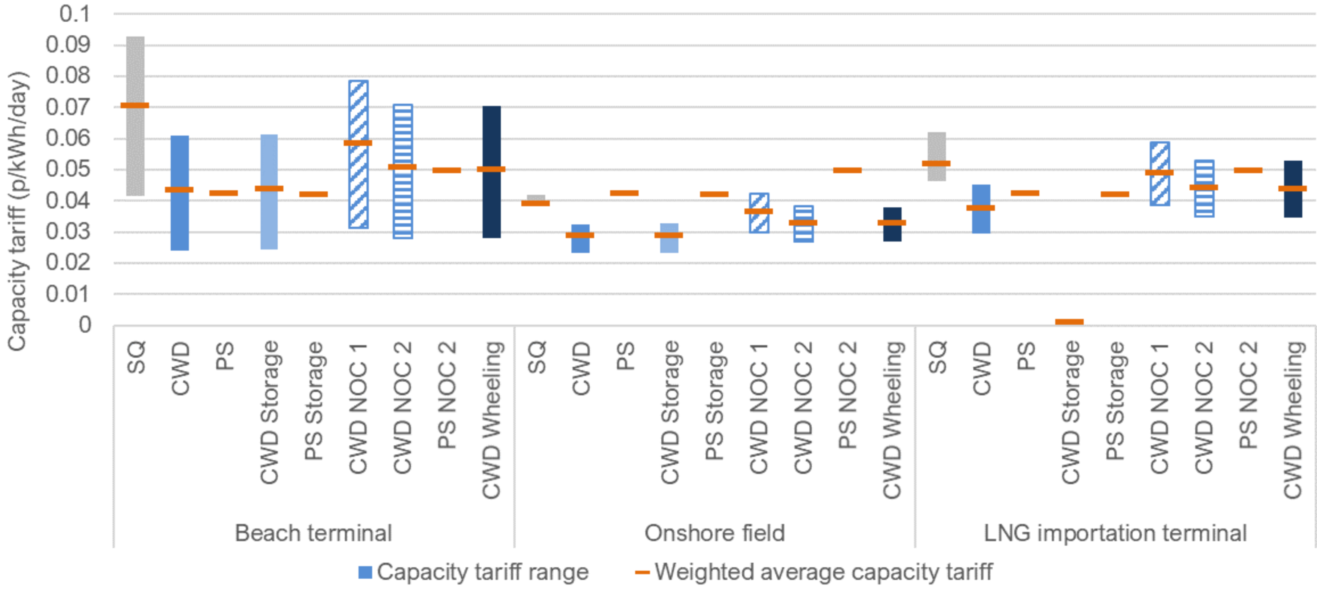
Note: For CWD Storage, the LMG tariff reflects the revenue recovery tariff component for existing contracts only (see Table 2.2), as these were sufficient to meet required capacity demand at these entry points for this modelled year under this option.

[84] Given our assumption that bookings are equal to flows for all points other than GDNs, the capacity tariff represents a charge on each unit of gas flowed – i.e. it is effectively 'commoditised'.

[85] Given that GDN bookings are assumed to be much higher than flows, 'commoditising' the capacity charge makes it appear larger. The ratio of GDN bookings to flows (in a given scenario and year) does not vary between tariff options, so this scaling up applies to all options equally.

[86] The commodity tariff is only levied on gas storage facility exit points for 'own use gas' which is a very small proportion of exit flows. We apply an exit commodity tariff of 0.06% to gas storage exit capacity which is consistent with this. This is reflected in the figures that follow.

Figure A.38: Annual weighted average tariffs at entry points under each option (TD, 2026-27, £18/19)



Note: For CWD Storage, the LMG tariff reflects the revenue recovery tariff component for existing contracts only (see Table 2.2), as these were sufficient to meet required capacity demand at these entry points for this modelled year under this option.

See Figure 3.3 for the annual weighted average tariffs at entry points under each option for TD, 2030-31.

Figure A.39: Annual weighted average tariffs at exit points under each option (TD, 2022-23, £18/19)

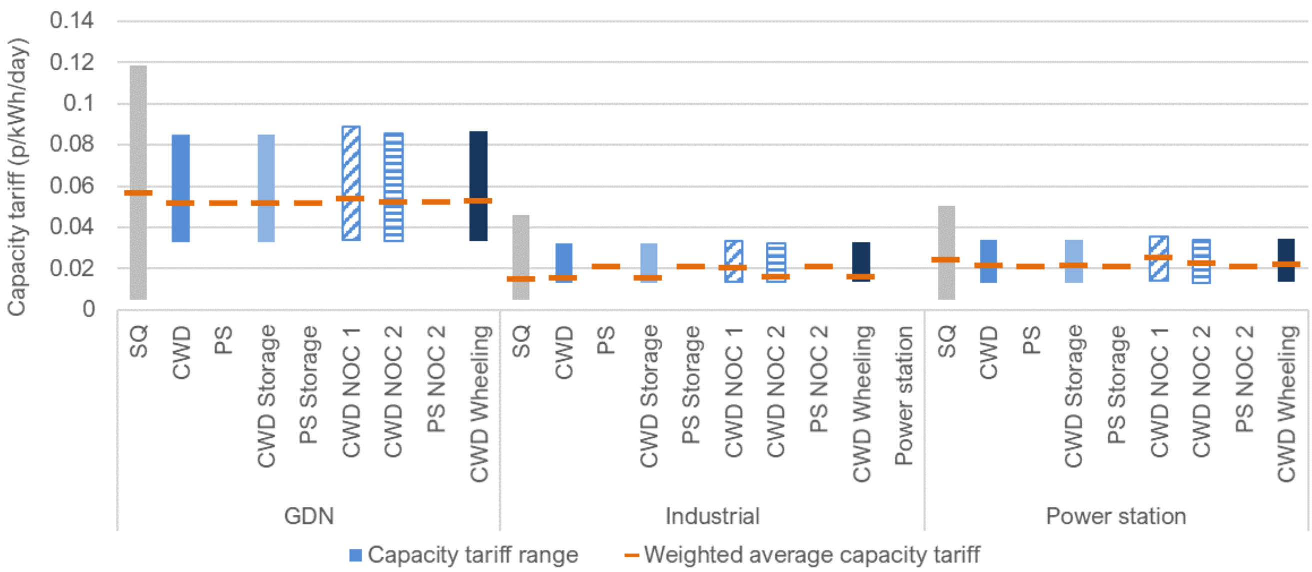
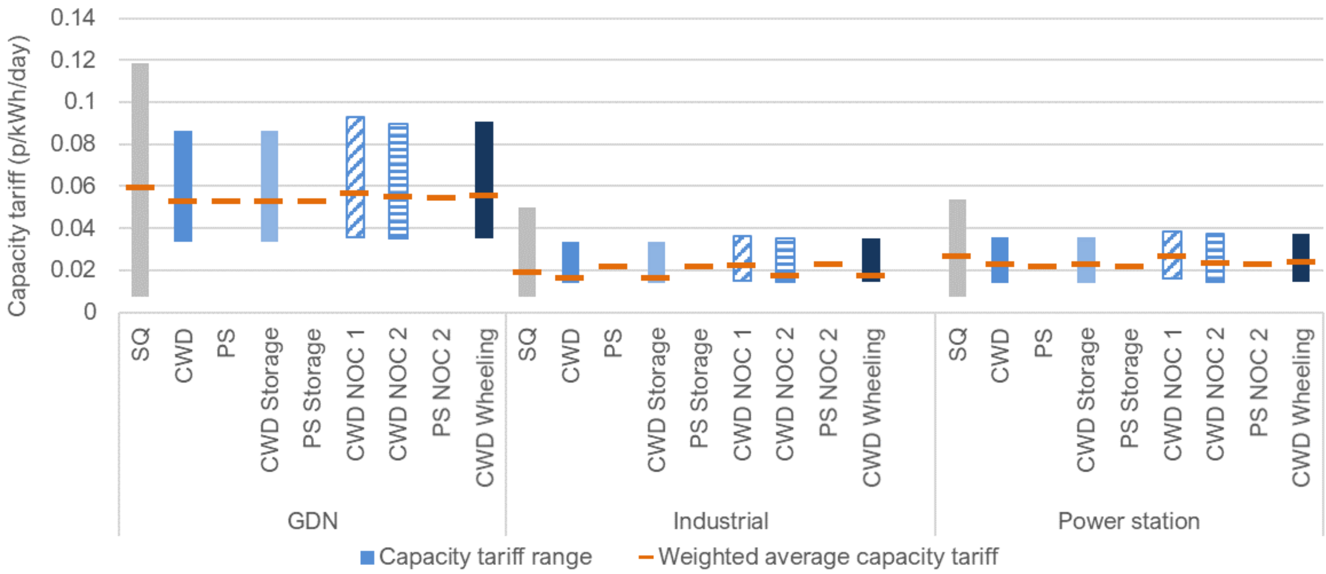


Figure A.40: Annual weighted average tariffs at exit points under each option (TD, 2026-67, £18/19)



See Figure 3.4 for the annual weighted average tariffs at exit points under each option for TD, 2030-31.

Figure A.41: Annual weighted average capacity tariffs at storage entry and exit points under each option (TD, 2022-23, £18/19)

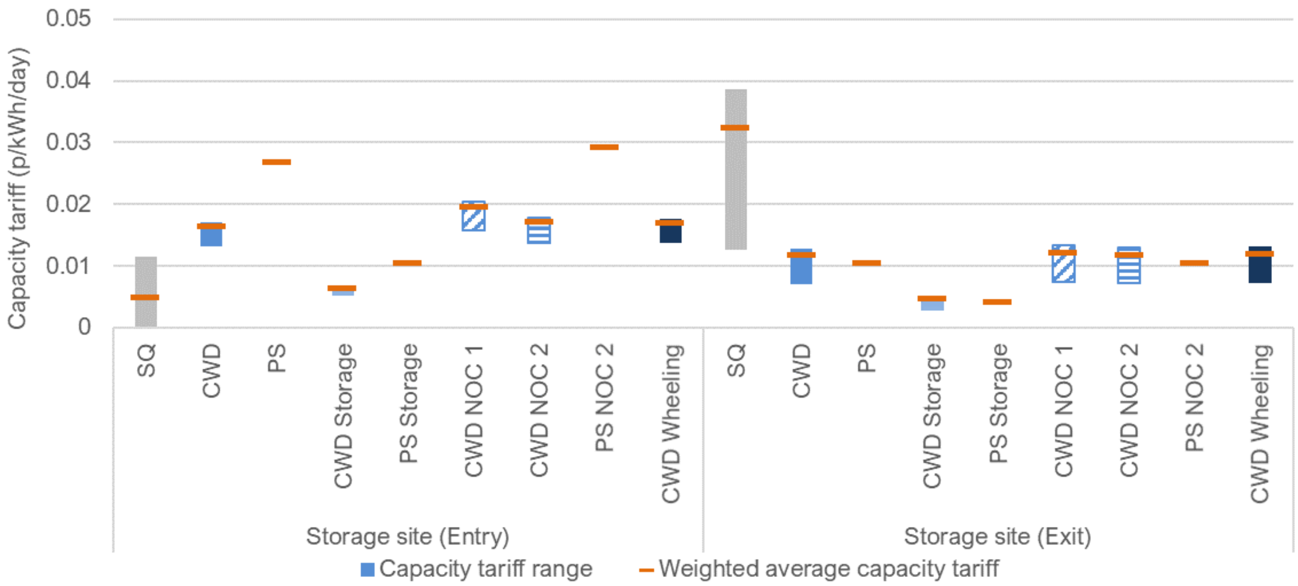
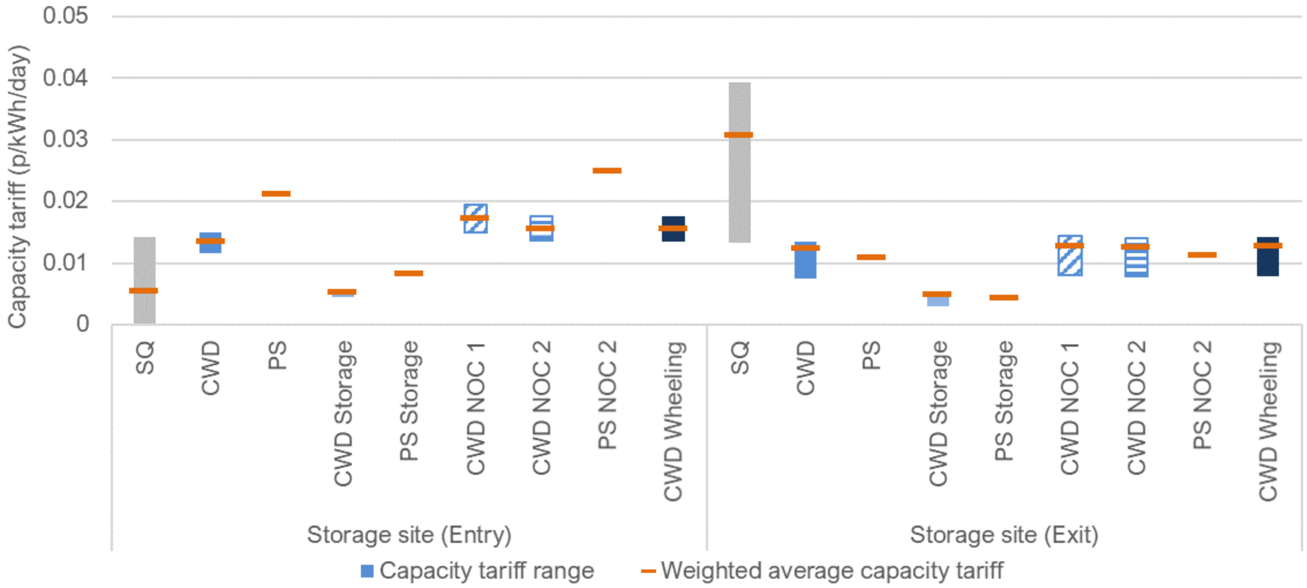


Figure A.42: Annual weighted average capacity tariffs at storage entry and exit points under each option (TD, 2026-27, £18/19)



See Figure 3.6 for annual weighted average capacity tariffs at storage entry and exit points under each option for TD, 2030-31.

Figure A.43: Annual weighted average capacity tariffs at interconnector entry and exit points under each option (TD, 2022-23, £18/19)

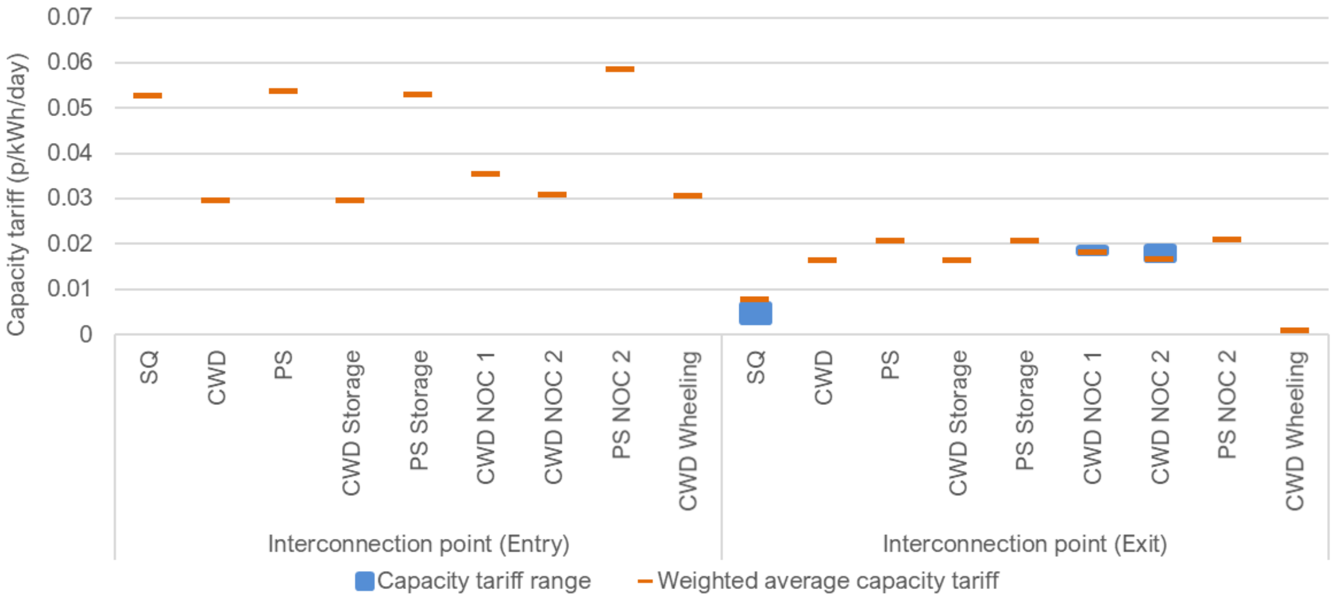
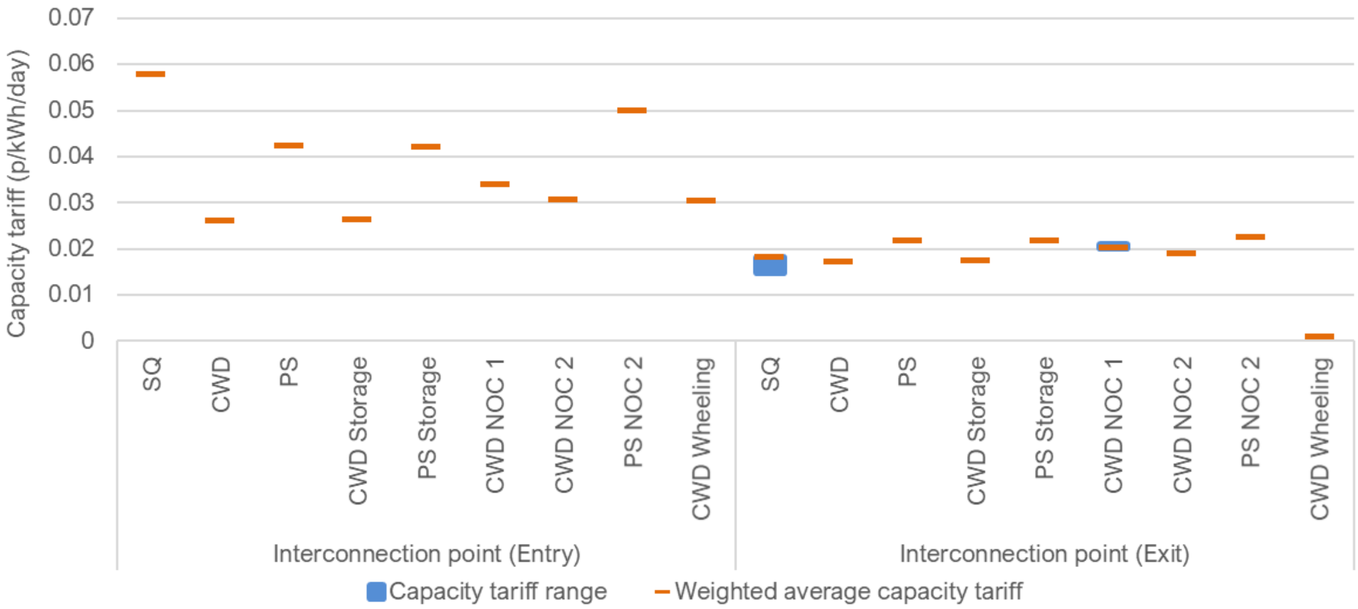


Figure A.44: Annual weighted average capacity tariffs at interconnector entry and exit points under each option (TD, 2026-27, £18/19)



See Figure 3.7 for annual weighted average capacity tariffs at interconnector entry and exit points under each option for TD, 2030-31.

A.2.2. Impacts of a NOC

See section 3.2.5.

A.2.3. Gas and electricity market price impacts

Figure A.45: *Estimated gas market price impacts under each option (TD, 2022-23, £18/19)*

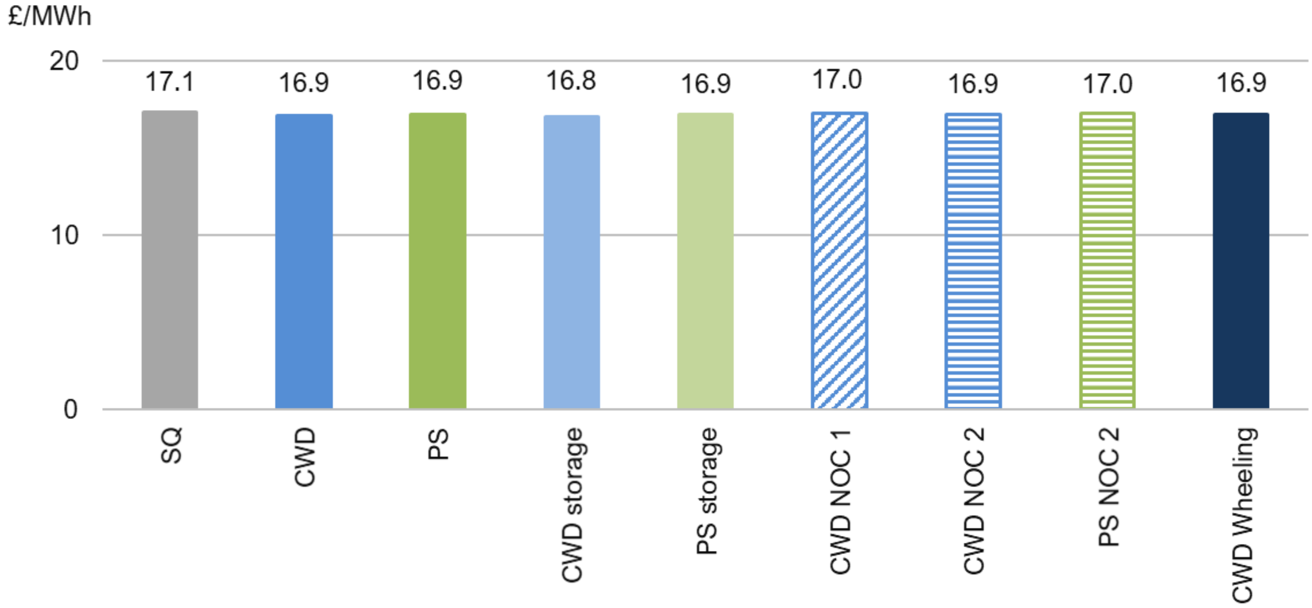
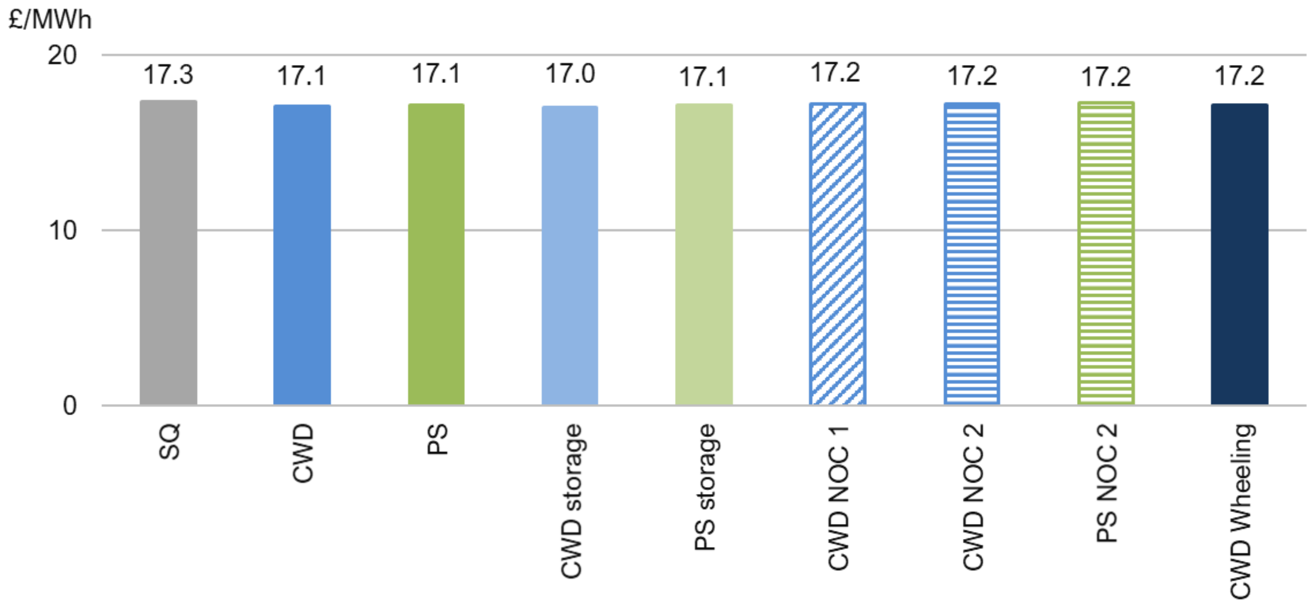


Figure A.46: *Estimated gas market price impacts under each option (TD, 2026-27, £18/19)*



See Figure 3.10 for the estimated gas market price impacts under each option for TD, 2030-31.

Figure A.47: Simulated wholesale electricity prices by option (TD, 2022-23, £18/19)

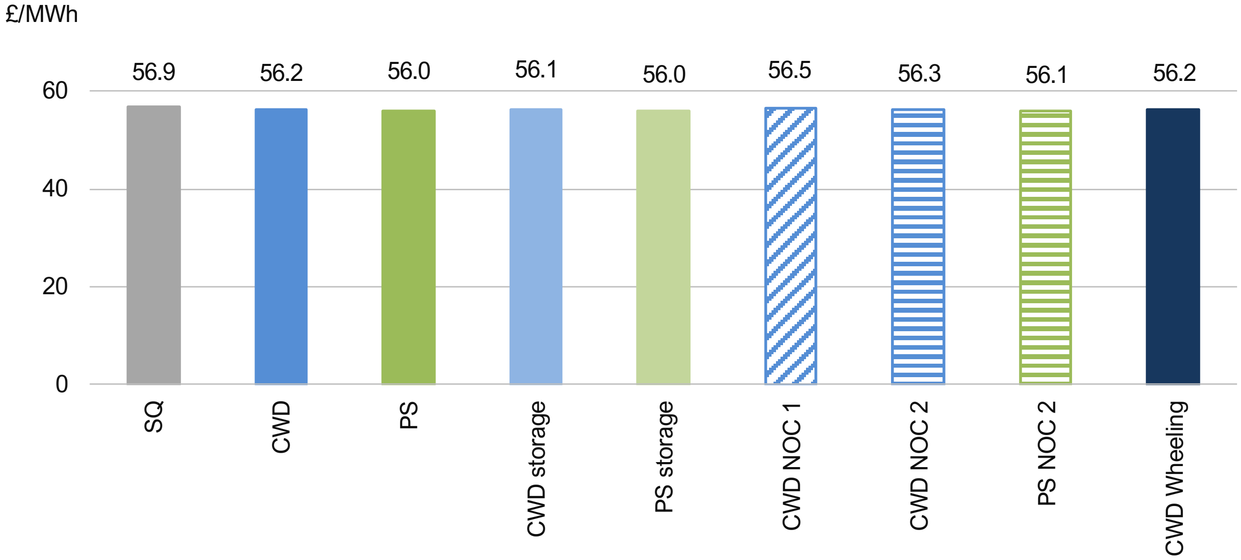
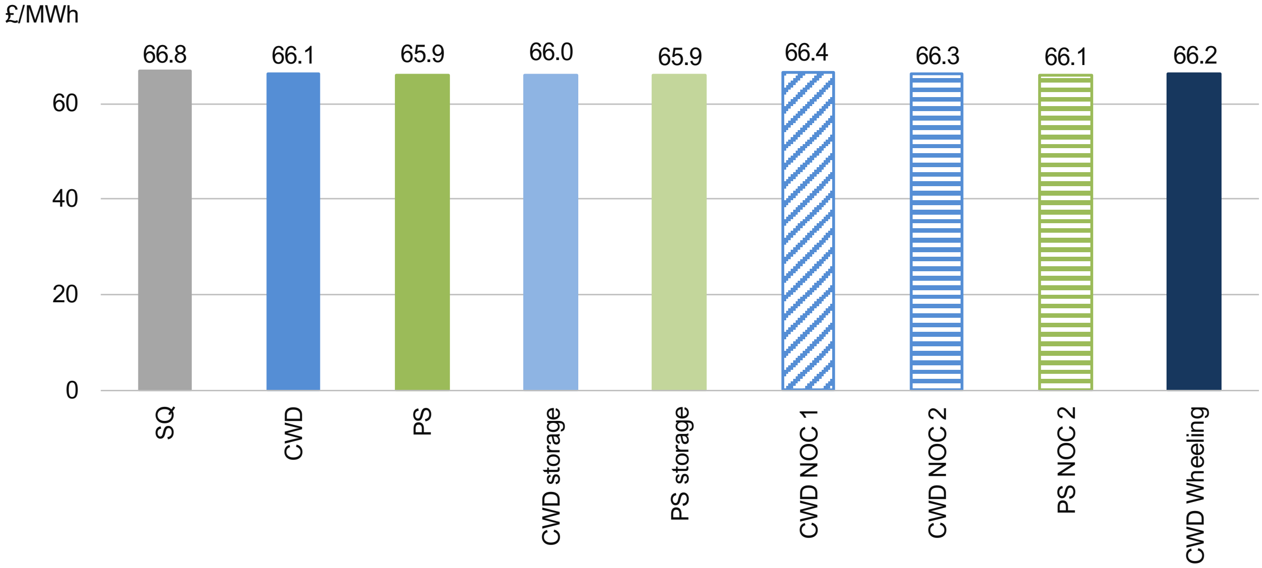


Figure A.48: Simulated wholesale electricity prices by option (TD, 2026-27, £18/19)



See Figure 3.11 for the simulated wholesale electricity prices by option for TD, 2030-31.

A.2.4. Consumer welfare

See Figure 3.12 and Figure 3.13 for gas and electricity consumer welfare impacts by option (TD, 2022-2031, NPV, discounted to £18/19).

A.2.5. Bill impacts

Figure A.49: Estimated bill impact for median consumption domestic gas consumers (TD, 2022-23, £18/19)

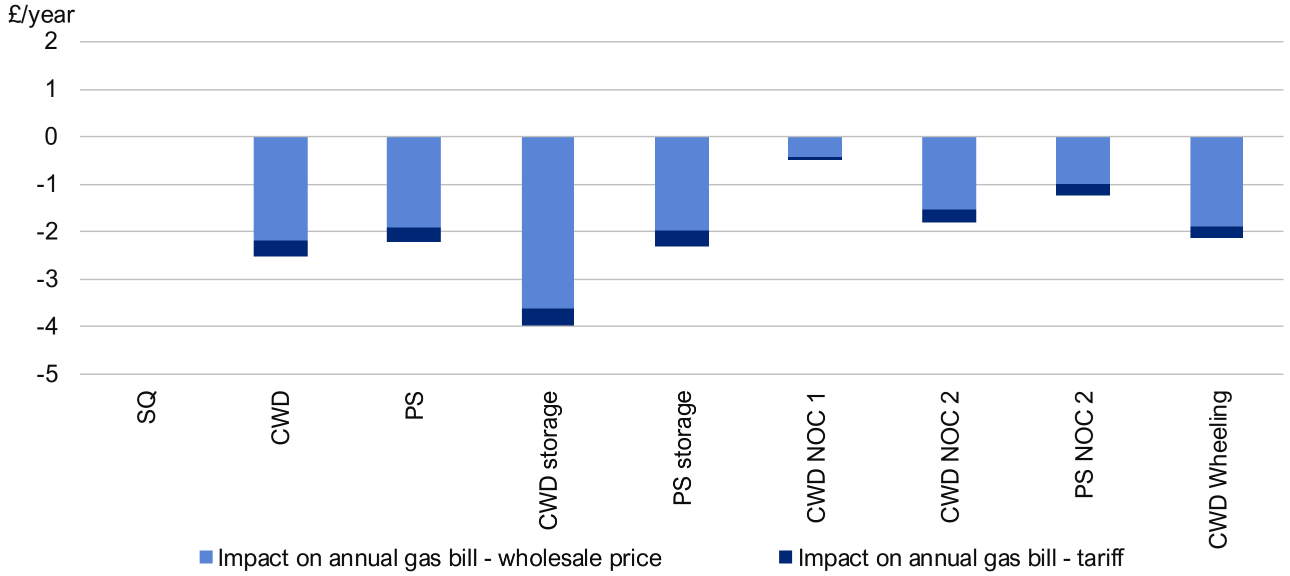
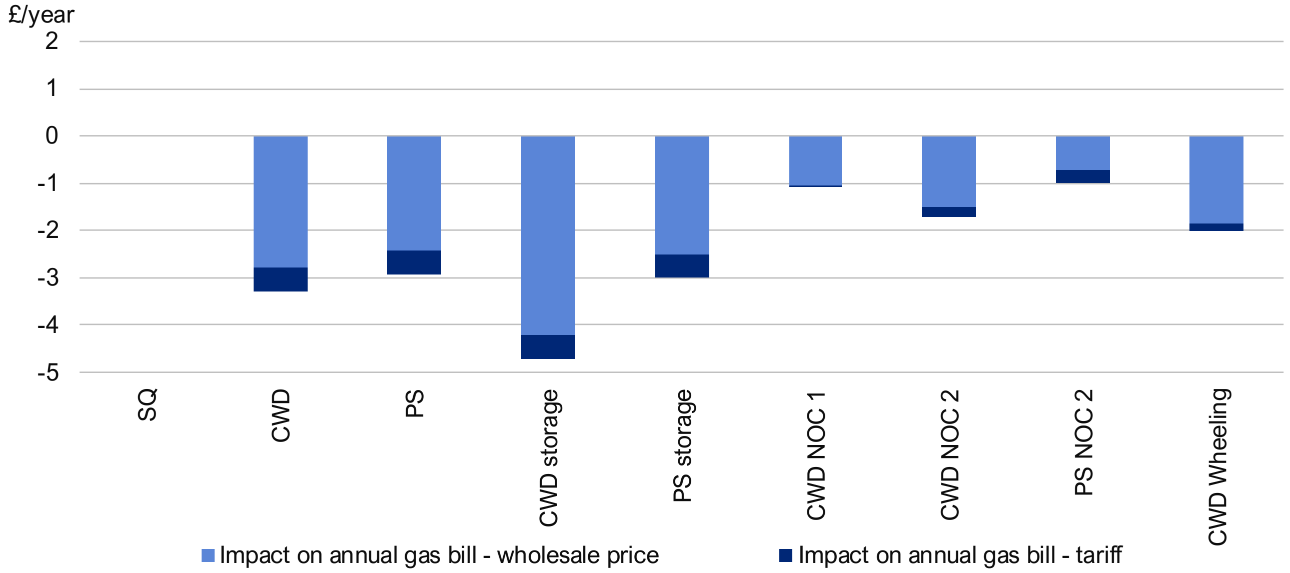


Figure A.50: Estimated bill impact for median consumption domestic gas consumers (TD, 2026-27, £18/19)



See Figure 3.14 for estimated bill impact for median consumption domestic gas consumers for TD, 2030-31.

Figure A.51: Estimated bill impact (gas only) for the median non-domestic consumer connected to the LDZ (TD, 2022-23, £18/19)

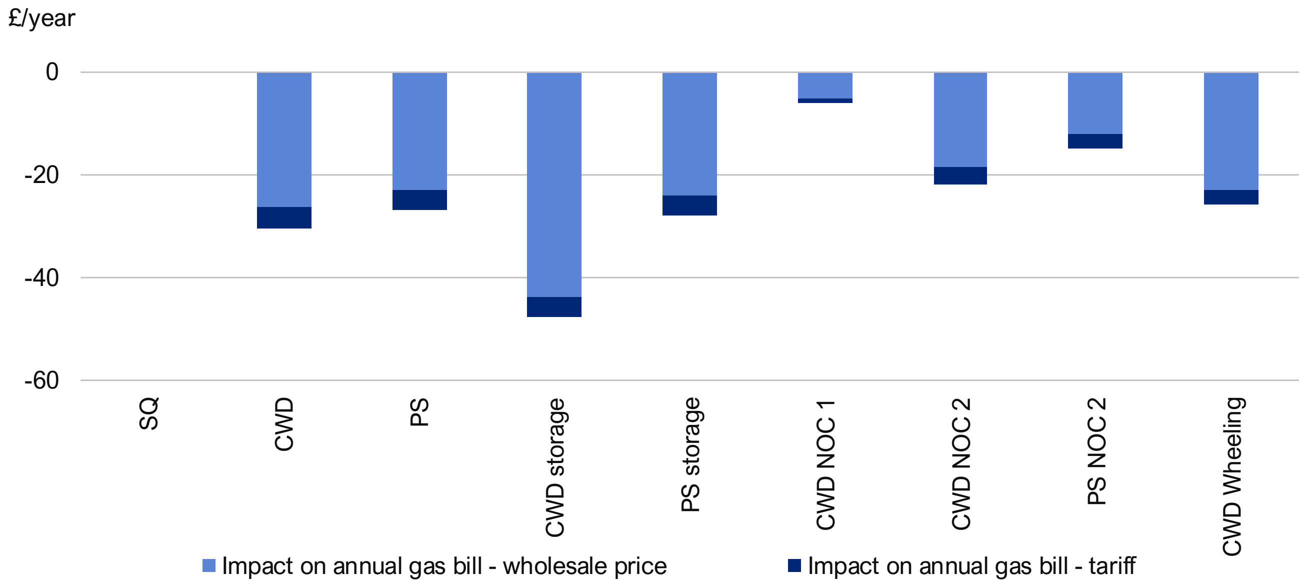
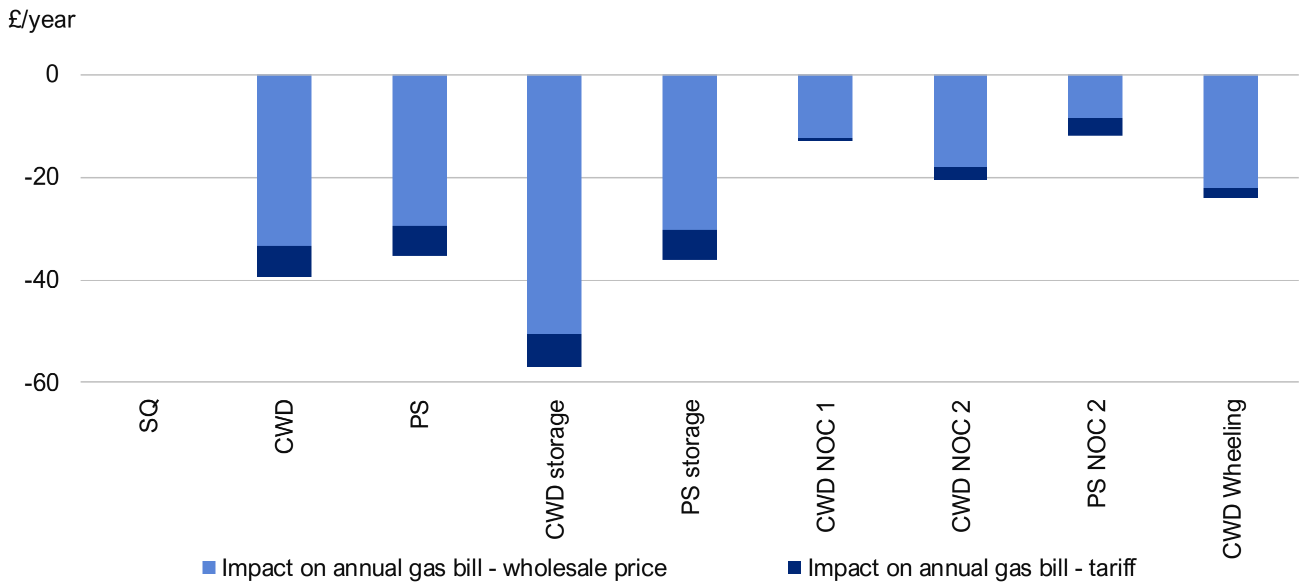


Figure A.52: Estimated bill impact (gas only) for the median non-domestic consumer connected to the LDZ (TD, 2026-27, £18/19)



See Figure 3.18 for estimated bill impact (gas only) for the median non-domestic consumer connected to the LDZ TD, 2030-31.

Figure A.53: Estimated bill impact (gas only) for the median non-domestic consumer connected to the NTS (TD, 2022-23, £18/19)

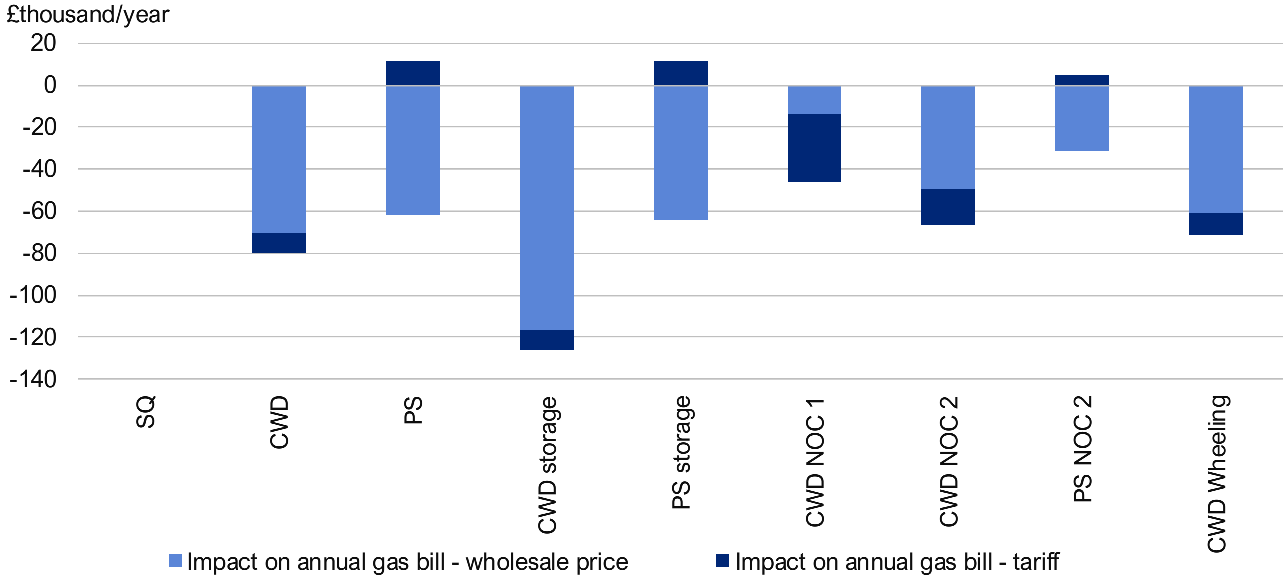
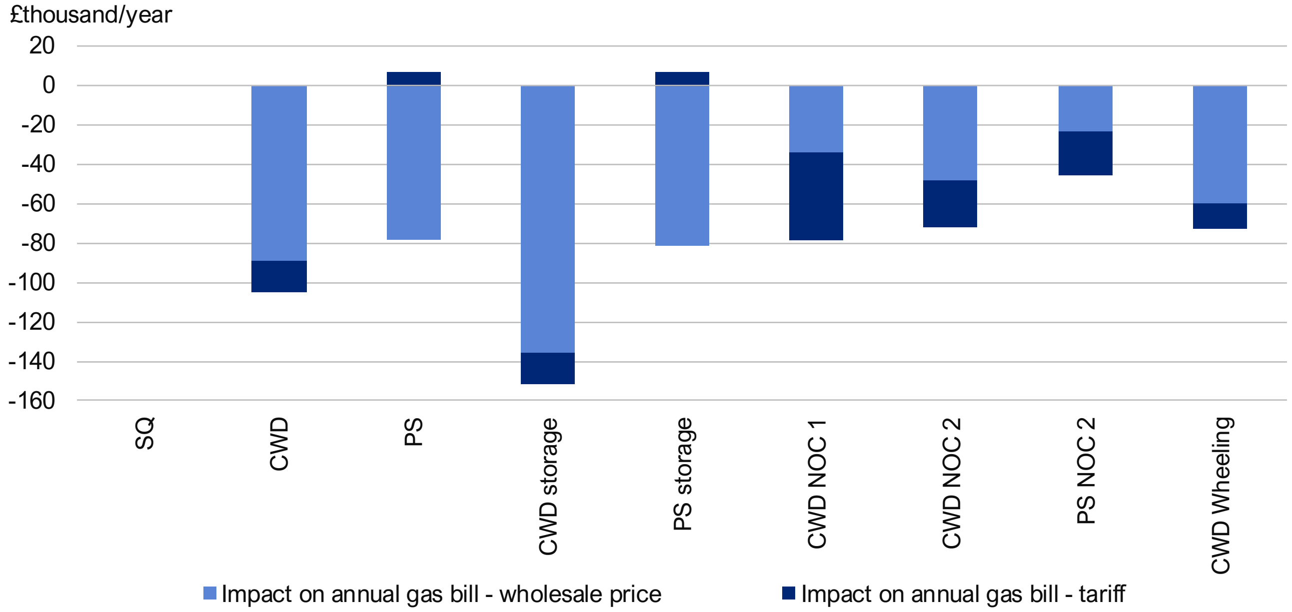


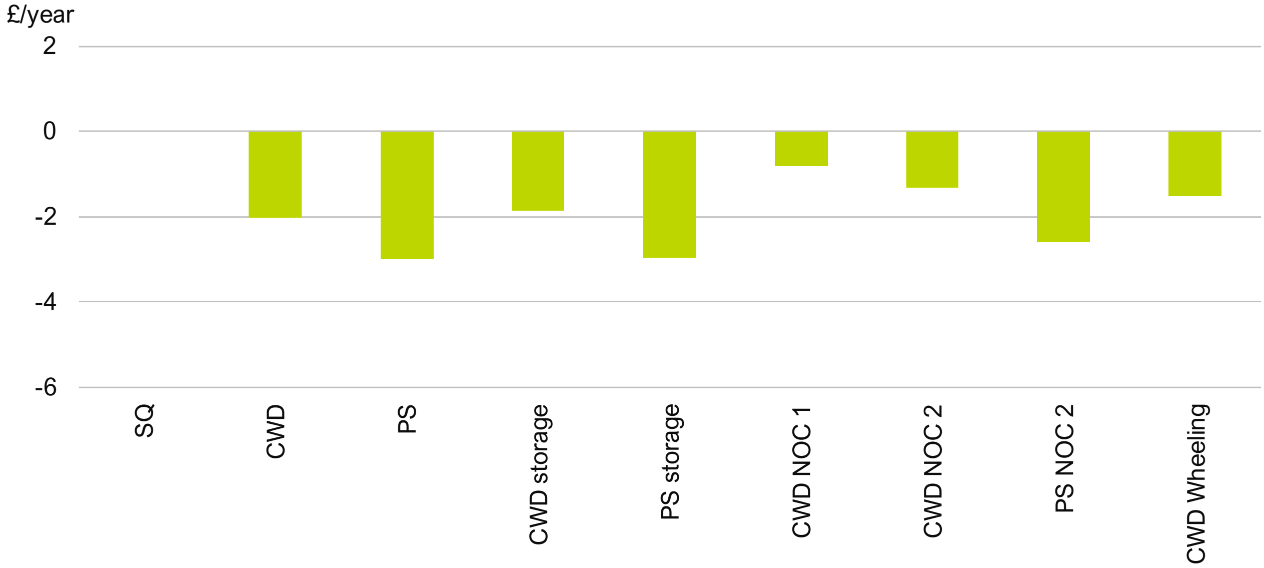
Figure A.54: Estimated bill impact (gas only) for the median non-domestic consumer connected to the NTS (TD, 2026-27, £18/19)



See Figure 3.19 for the estimated bill impact (gas only) for the median non-domestic consumer connected to the NTS for TD, 2030-31.

See Figure 3.20 for the estimated bill impact for median consumption domestic electricity consumers for TD, 2030-31 (£18/19), and Figure 3.21 for the estimated bill impact for median consumption non-domestic electricity consumers for TD, 2030-31 (£18/19).

Figure A.55: Estimated bill impact for the most fuel poor quintile domestic electricity consumers (TD, 2030-31, £18/19)



A.2.6. Impacts on power stations and producer revenues

See the following figures:

- Figure 3.22 for impacts on revenues of GB gas-fired power stations (NPV, 2022-2031, £2018/19),
- Figure 3.23 for impacts on revenues of LNG terminals, beach terminals and onshore fields (NPV, 2022-2031, £2018/19),
- Figure 3.24 for impacts on revenues of gas interconnectors (NPV, 2022-2031, £2018/19), and
- Figure 3.27 for impacts on total revenues of collective GB gas storage facilities (NPV, 2022-2031, £2018/19).

A.2.7. Bypass analysis

See section 4.2.

CEPA economics matters

Appendix B DATA TABLES FOR DETAILED RESULTS

In this appendix, we provide data tables for the key results and charts included in Appendix A and the main report.

B.1. Steady Progression

B.1.1. Tariff impacts

We note that for GDN exit point tariffs we 'commoditise' the capacity element of the charge.[87]

For the status quo, we note that the 'weighted average capacity tariff' in these tables *includes* the commodity tariff, for comparability with the other tariff options. We also note that under the status quo, the commodity tariff is not paid at storage entry or exit points.[88]

All tariffs are presented in p/KWh (per day).

Table B.1: Annual weighted average tariffs at entry points under each option, including storage and interconnector entry tariffs (SP, 2022-23, £18/19)

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
Beach terminal				
SQ	0.001000	0.052500	0.064530	0.033210
CWD	0.025111	0.038561	0.051278	
PS	0.049291	0.000000	0.049291	
CWD Storage	0.025048	0.038464	0.051115	
PS Storage	0.048758	0.000000	0.048758	
CWD NOC 1	0.028888	0.044354	0.065298	
CWD NOC 2	0.025927	0.039809	0.054453	
PS NOC 2	0.053066	0.000000	0.053066	
CWD Wheeling	0.025857	0.039695	0.052725	
Onshore field				
SQ	0.000100	0.002200	0.033314	0.033210
CWD	0.024229	0.009576	0.029826	
PS	0.049291	0.000000	0.049291	
CWD Storage	0.024170	0.009544	0.029752	
PS Storage	0.048758	0.000000	0.048758	
CWD NOC 1	0.027873	0.011029	0.033628	
CWD NOC 2	0.025016	0.009889	0.030177	
PS NOC 2	0.053066	0.000000	0.053066	
CWD Wheeling	0.024948	0.009863	0.030095	
LNG importation terminal				
SQ	0.001600	0.023400	0.044684	0.033210
CWD	0.030890	0.016273	0.039026	
PS	0.049291	0.000000	0.049291	
CWD Storage	0.000770	0.000406	0.000973	

[87] Given that GDN bookings are assumed to be much higher than flows, 'commoditising' the capacity charge makes it appear larger. The ratio of GDN bookings to flows (in a given scenario and year) does not vary between tariff options, so this scaling up applies to all options equally.

[88] The commodity tariff is only levied on gas storage facility exit points for 'own use gas' which is a very small proportion of exit flows. We apply an exit commodity tariff of 0.06% to gas storage exit capacity which is consistent with this. This is what is shown in these data tables.

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
PS Storage	0.048758	0.000000	0.048758	
CWD NOC 1	0.035542	0.018723	0.044903	
CWD NOC 2	0.031895	0.016801	0.040295	
PS NOC 2	0.053066	0.000000	0.053066	
CWD Wheeling	0.031810	0.016754	0.040186	
Interconnector (Entry)				
SQ	0.011700	0.000000	0.044910	0.033210
CWD	0.027037	0.000000	0.027037	
PS	0.049291	0.000000	0.049291	
CWD Storage	0.026969	0.000000	0.026969	
PS Storage	0.048758	0.000000	0.048758	
CWD NOC 1	0.031106	0.000000	0.031106	
CWD NOC 2	0.027916	0.000000	0.027916	
PS NOC 2	0.053066	0.000000	0.053066	
CWD Wheeling	0.027841	0.000000	0.027841	
Storage site (Entry)				
SQ	0.000100	0.013100	0.004492	N/A
CWD	0.012114	0.003449	0.014911	
PS	0.024645	0.000000	0.024645	
CWD Storage	0.004713	0.001340	0.005800	
PS Storage	0.009528	0.000000	0.009528	
CWD NOC 1	0.013936	0.003974	0.017158	
CWD NOC 2	0.012508	0.003562	0.015396	
PS NOC 2	0.026533	0.000000	0.026533	
CWD Wheeling	0.012474	0.003553	0.015355	

Note: For CWD Storage, the LMG tariff reflects the revenue recovery tariff component for existing contracts only (see Table 2.2), as these were sufficient to meet required capacity demand at these entry points for this modelled year under this option.

Table B.2: Annual weighted average tariffs at entry points under each option, including storage and interconnector entry tariffs (SP, 2026-27, £18/19)

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
Beach terminal				
SQ	0.000200	0.053300	0.063731	0.030762
CWD	0.022409	0.034417	0.040965	
PS	0.039657	0.000000	0.039657	
CWD Storage	0.022453	0.034483	0.041009	
PS Storage	0.039542	0.000000	0.039542	
CWD NOC 1	0.023209	0.035968	0.046907	
CWD NOC 2	0.021642	0.033542	0.041270	
PS NOC 2	0.039555	0.000000	0.039555	
CWD Wheeling	0.021579	0.033440	0.040826	
Onshore field				
SQ	0.000100	0.001400	0.030865	0.030762
CWD	0.021622	0.008535	0.026619	
PS	0.039657	0.000000	0.039657	
CWD Storage	0.021665	0.008546	0.026671	
PS Storage	0.039542	0.000000	0.039542	

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
CWD NOC 1	0.022435	0.008516	0.026879	
CWD NOC 2	0.020921	0.007935	0.025062	
PS NOC 2	0.039555	0.000000	0.039555	
CWD Wheeling	0.020859	0.007913	0.024988	
LNG importation terminal				
SQ	0.001300	0.024200	0.043939	0.030762
CWD	0.027570	0.014529	0.034835	
PS	0.039657	0.000000	0.039657	
CWD Storage	0.000852	0.000449	0.001076	
PS Storage	0.039542	0.000000	0.039542	
CWD NOC 1	0.028411	0.015145	0.035984	
CWD NOC 2	0.026490	0.014122	0.033551	
PS NOC 2	0.039555	0.000000	0.039555	
CWD Wheeling	0.026414	0.014080	0.033453	
Interconnector (Entry)				
SQ	0.013500	0.000000	0.044262	0.030762
CWD	0.024131	0.000000	0.024131	
PS	0.039657	0.000000	0.039657	
CWD Storage	0.024178	0.000000	0.024178	
PS Storage	0.039542	0.000000	0.039542	
CWD NOC 1	0.024939	0.000000	0.024939	
CWD NOC 2	0.023254	0.000000	0.023254	
PS NOC 2	0.039555	0.000000	0.039555	
CWD Wheeling	0.023187	0.000000	0.023187	
Storage site (Entry)				
SQ	0.000100	0.014000	0.004915	N/A
CWD	0.010811	0.003071	0.012552	
PS	0.019829	0.000000	0.019829	
CWD Storage	0.004199	0.001191	0.004874	
PS Storage	0.007657	0.000000	0.007657	
CWD NOC 1	0.011218	0.002996	0.012880	
CWD NOC 2	0.010460	0.002791	0.012009	
PS NOC 2	0.019778	0.000000	0.019778	
CWD Wheeling	0.010430	0.002783	0.011974	

Note: For CWD Storage, the LMG tariff reflects the revenue recovery tariff component for existing contracts only (see Table 2.2), as these were sufficient to meet required capacity demand at these entry points for this modelled year under this option.

Table B.3: Annual weighted average tariffs at entry points under each option, including storage and interconnector entry tariffs (SP, 2030-31, £18/19)

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
Beach terminal				
SQ	0.000500	0.049800	0.063415	0.031397
CWD	0.022814	0.035073	0.039355	
PS	0.038346	0.000000	0.038346	
CWD Storage	0.022861	0.035144	0.039400	
PS Storage	0.038423	0.000000	0.038423	
CWD NOC 1	0.024131	0.037368	0.045658	

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
CWD NOC 2	0.022600	0.034997	0.040944	
PS NOC 2	0.038443	0.000000	0.038443	
CWD Wheeling	0.022497	0.034834	0.040418	
Onshore field				
SQ	0.000100	0.001000	0.031499	0.031397
CWD	0.022020	0.008628	0.027112	
PS	0.038346	0.000000	0.038346	
CWD Storage	0.022066	0.008638	0.027167	
PS Storage	0.038423	0.000000	0.038423	
CWD NOC 1	0.023323	0.008825	0.027929	
CWD NOC 2	0.021843	0.008262	0.026155	
PS NOC 2	0.038443	0.000000	0.038443	
CWD Wheeling	0.021743	0.008225	0.026036	
LNG importation terminal				
SQ	0.000900	0.024200	0.043781	0.031397
CWD	0.028043	0.014795	0.035358	
PS	0.038346	0.000000	0.038346	
CWD Storage	0.028099	0.014824	0.035854	
PS Storage	0.038423	0.000000	0.038423	
CWD NOC 1	0.029528	0.015768	0.029528	
CWD NOC 2	0.027652	0.014766	0.035825	
PS NOC 2	0.038443	0.000000	0.038443	
CWD Wheeling	0.027527	0.014698	0.037129	
Interconnector (Entry)				
SQ	0.014400	0.000000	0.045797	0.031397
CWD	0.024559	0.000000	0.024559	
PS	0.038346	0.000000	0.038346	
CWD Storage	0.024608	0.000000	0.024608	
PS Storage	0.038423	0.000000	0.038423	
CWD NOC 1	0.025927	0.000000	0.025927	
CWD NOC 2	0.024280	0.000000	0.024280	
PS NOC 2	0.038443	0.000000	0.038443	
CWD Wheeling	0.024170	0.000000	0.024170	
Storage site (Entry)				
SQ	0.000100	0.013300	0.004365	N/A
CWD	0.011010	0.003092	0.012730	
PS	0.019173	0.000000	0.019173	
CWD Storage	0.004266	0.001196	0.004930	
PS Storage	0.007409	0.000000	0.007409	
CWD NOC 1	0.011662	0.003100	0.013387	
CWD NOC 2	0.010922	0.002902	0.012537	
PS NOC 2	0.019222	0.000000	0.019222	
CWD Wheeling	0.010872	0.002889	0.012478	

Table B.4: *Annual weighted average tariffs at exit points under each option, including storage and interconnector exit tariffs (SP, 2022-23, £18/19)*

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
GDN				
SQ	0.000253	0.105128	0.053914	0.005665
CWD	0.031802	0.049885	0.049611	
PS	0.049787	0.000000	0.049787	
CWD Storage	0.031840	0.049826	0.049628	
PS Storage	0.049807	0.000000	0.049807	
CWD NOC 1	0.032744	0.051993	0.051333	
CWD NOC 2	0.031741	0.049765	0.049499	
PS NOC 2	0.049930	0.000000	0.049930	
CWD Wheeling	0.032189	0.050478	0.050208	
Industrial				
SQ	0.000100	0.038100	0.015190	0.005665
CWD	0.012736	0.017796	0.014520	
PS	0.019654	0.000000	0.019654	
CWD Storage	0.012749	0.017773	0.014546	
PS Storage	0.019661	0.000000	0.019661	
CWD NOC 1	0.013091	0.018551	0.018127	
CWD NOC 2	0.012714	0.017753	0.014710	
PS NOC 2	0.019710	0.000000	0.019710	
CWD Wheeling	0.012891	0.018007	0.014729	
Power station				
SQ	0.000100	0.041500	0.023073	0.005665
CWD	0.012591	0.019655	0.020556	
PS	0.019654	0.000000	0.019654	
CWD Storage	0.012604	0.019634	0.020556	
PS Storage	0.019661	0.000000	0.019661	
CWD NOC 1	0.013232	0.020218	0.024314	
CWD NOC 2	0.012569	0.019606	0.021354	
PS NOC 2	0.019710	0.000000	0.019710	
CWD Wheeling	0.012745	0.019888	0.021009	
Interconnector (Exit)				
SQ	0.008800	0.000000	0.014465	0.005665
CWD	0.015186	0.000000	0.015186	
PS	0.019654	0.000000	0.019654	
CWD Storage	0.015239	0.000000	0.015239	
PS Storage	0.019661	0.000000	0.019661	
CWD NOC 1	0.016210	0.000000	0.016210	
CWD NOC 2	0.015108	0.000000	0.015108	
PS NOC 2	0.019710	0.000000	0.019710	
CWD Wheeling	0.000768	0.000000	0.000768	

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
Storage site (Exit)				
SQ	0.011400	0.023500	0.029439	0.000003
CWD	0.006797	0.005493	0.011154	
PS	0.009827	0.000000	0.009827	
CWD Storage	0.002678	0.002158	0.004492	
PS Storage	0.003870	0.000000	0.003870	
CWD NOC 1	0.006998	0.005674	0.011488	
CWD NOC 2	0.006785	0.005482	0.011127	
PS NOC 2	0.009855	0.000000	0.009855	
CWD Wheeling	0.006880	0.005559	0.011283	

Table B.5: Annual weighted average tariffs at exit points under each option, including storage and interconnector exit tariffs (SP, 2026-27, £18/19)

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
GDN				
SQ	0.000250	0.101578	0.052332	0.005430
CWD	0.031367	0.049202	0.048913	
PS	0.049104	0.000000	0.049104	
CWD Storage	0.031404	0.049144	0.048930	
PS Storage	0.049122	0.000000	0.049122	
CWD NOC 1	0.032732	0.049261	0.049996	
CWD NOC 2	0.031570	0.047515	0.048220	
PS NOC 2	0.048464	0.000000	0.048464	
CWD Wheeling	0.031806	0.047749	0.048528	
Industrial				
SQ	0.000100	0.037300	0.015536	0.005430
CWD	0.012750	0.017816	0.014536	
PS	0.019675	0.000000	0.019675	
CWD Storage	0.012763	0.017793	0.014562	
PS Storage	0.019682	0.000000	0.019682	
CWD NOC 1	0.013292	0.017819	0.017634	
CWD NOC 2	0.012822	0.017188	0.014621	
PS NOC 2	0.019418	0.000000	0.019418	
CWD Wheeling	0.012923	0.017272	0.014606	
Power station				
SQ	0.000100	0.040700	0.023755	0.005430
CWD	0.012605	0.019677	0.020588	
PS	0.019675	0.000000	0.019675	
CWD Storage	0.012618	0.019656	0.020588	
PS Storage	0.019682	0.000000	0.019682	
CWD NOC 1	0.013909	0.018943	0.023485	
CWD NOC 2	0.012681	0.019007	0.020664	
PS NOC 2	0.019418	0.000000	0.019418	
CWD Wheeling	0.012781	0.019095	0.020734	

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
Interconnector (Exit)				
SQ	0.009700	0.000000	0.015130	0.005430
CWD	0.015203	0.000000	0.015203	
PS	0.019675	0.000000	0.019675	
CWD Storage	0.015256	0.000000	0.015256	
PS Storage	0.019682	0.000000	0.019682	
CWD NOC 1	0.015749	0.000000	0.015749	
CWD NOC 2	0.015138	0.000000	0.015138	
PS NOC 2	0.019418	0.000000	0.019418	
CWD Wheeling	0.000756	0.000000	0.000756	
Storage site (Exit)				
SQ	0.012400	0.021700	0.029109	0.000003
CWD	0.006805	0.005499	0.011166	
PS	0.009837	0.000000	0.009837	
CWD Storage	0.002681	0.002160	0.004497	
PS Storage	0.003873	0.000000	0.003873	
CWD NOC 1	0.007052	0.005484	0.011423	
CWD NOC 2	0.006802	0.005294	0.011027	
PS NOC 2	0.009709	0.000000	0.009709	
CWD Wheeling	0.006853	0.005330	0.011109	

Table B.6: Annual weighted average tariffs at exit points under each option, including storage and interconnector exit tariffs (SP, 2030-31, £18/19)

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
GDN				
SQ	0.000244	0.092161	0.051909	0.007247
CWD	0.031013	0.048647	0.048367	
PS	0.048579	0.000000	0.048579	
CWD Storage	0.031050	0.048590	0.048385	
PS Storage	0.048598	0.000000	0.048598	
CWD NOC 1	0.032649	0.048864	0.049665	
CWD NOC 2	0.031529	0.047039	0.047899	
PS NOC 2	0.048128	0.000000	0.048128	
CWD Wheeling	0.031816	0.047549	0.048363	
Industrial				
SQ	0.000100	0.037700	0.017742	0.007247
CWD	0.012870	0.017983	0.014673	
PS	0.019872	0.000000	0.019872	
CWD Storage	0.012883	0.017960	0.014699	
PS Storage	0.019880	0.000000	0.019880	
CWD NOC 1	0.013515	0.018038	0.018285	
CWD NOC 2	0.013051	0.017368	0.014987	
PS NOC 2	0.019688	0.000000	0.019688	
CWD Wheeling	0.013170	0.017557	0.015074	

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
Power station				
SQ	0.000100	0.038100	0.024310	0.007247
CWD	0.012724	0.019862	0.020795	
PS	0.019872	0.000000	0.019872	
CWD Storage	0.012737	0.019841	0.020795	
PS Storage	0.019880	0.000000	0.019880	
CWD NOC 1	0.013366	0.019978	0.023603	
CWD NOC 2	0.012907	0.019232	0.020936	
PS NOC 2	0.019688	0.000000	0.019688	
CWD Wheeling	0.013025	0.019441	0.021001	
Interconnector (Exit)				
SQ	0.010100	0.000000	0.017347	0.007247
CWD	0.015346	0.000000	0.015346	
PS	0.019872	0.000000	0.019872	
CWD Storage	0.015400	0.000000	0.015400	
PS Storage	0.019880	0.000000	0.019880	
CWD NOC 1	0.016545	0.000000	0.016545	
CWD NOC 2	0.015862	0.000000	0.015862	
PS NOC 2	0.019688	0.000000	0.019688	
CWD Wheeling	0.000801	0.000000	0.000801	
Storage site (Exit)				
SQ	0.012800	0.009500	0.020102	0.000004
CWD	0.006869	0.005551	0.011271	
PS	0.009936	0.000000	0.009936	
CWD Storage	0.002705	0.002180	0.004538	
PS Storage	0.003911	0.000000	0.003911	
CWD NOC 1	0.007168	0.005483	0.011537	
CWD NOC 2	0.006920	0.005289	0.011135	
PS NOC 2	0.009844	0.000000	0.009844	
CWD Wheeling	0.006983	0.005347	0.011245	

B.1.2. Gas and electricity market price impacts

Table B.7: Simulated gas and electricity prices (SP, £18/19)

Tariff option	Wholesale gas price, £/MWh	Wholesale electricity price, £/MWh
2022-23 modelled year		
SQ	19.36	50.64
CWD	19.14	49.94
PS	19.17	49.71
CWD storage	19.10	49.88
PS storage	19.17	49.70
CWD NOC 1	19.23	50.16
CWD NOC 2	19.17	49.94
PS NOC 2	19.25	49.81
CWD Wheeling	19.16	49.93

Tariff option	Wholesale gas price, £/MWh	Wholesale electricity price, £/MWh
2026-27 modelled year		
SQ	22.33	58.72
CWD	22.06	57.94
PS	22.11	57.74
CWD storage	22.04	57.90
PS storage	22.11	57.74
CWD NOC 1	22.07	57.98
CWD NOC 2	22.06	57.88
PS NOC 2	22.14	57.75
CWD Wheeling	22.06	57.87
2030-31 modelled year		
SQ	21.94	57.78
CWD	21.67	57.02
PS	21.72	56.81
CWD storage	21.67	57.02
PS storage	21.72	56.81
CWD NOC 1	21.69	57.07
CWD NOC 2	21.67	56.95
PS NOC 2	21.73	56.79
CWD Wheeling	21.67	56.96

B.1.3. Consumer welfare

Tariff option	Wholesale gas price impact - residential & I&C consumers				Gas tariff impacts - residential & I&C consumers				Power stations		Net impact
	Domestic consumers	LDZ-connected I&C consumers	NTS-connected I&C consumers	Total	Domestic consumers	LDZ-connected I&C consumers	NTS-connected I&C consumers	Total	Wholesale gas price impact	Gas tariff impacts	
SQ	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CWD	651.7	396.7	39.9	1088.2	41.3	25.0	5.9	72.2	640.2	-461.8	1338.8
PS	538.6	327.8	32.9	899.3	36.4	22.0	-2.1	56.2	560.6	-441.5	1074.7
CWD storage	699.0	424.8	42.8	1166.6	40.8	24.7	5.9	71.5	683.3	-463.3	1458.1
PS storage	541.6	329.5	33.1	904.3	35.9	21.7	-2.1	55.5	562.8	-441.4	1081.1
CWD NOC 1	561.7	343.2	34.2	939.0	7.4	4.5	16.5	28.4	484.0	24.0	1475.4
CWD NOC 2	640.1	390.2	39.1	1069.4	53.0	32.2	9.1	94.3	609.6	-242.5	1530.8
PS NOC 2	444.9	271.8	27.1	743.8	45.6	27.7	3.6	76.8	440.2	-114.2	1146.7
CWD Wheeling	639.0	389.2	39.0	1067.2	41.1	25.0	6.2	72.2	611.5	-338.2	1412.7

Tariff option	Wholesale electricity price impact - residential & I&C consumers			Wholesale electricity price impact - power stations
	Domestic consumers	I&C consumers	Total	
SQ	0.0	0.0	0.0	0.0
CWD	616.4	1049.2	1665.7	-983.3
PS	784.9	1335.9	2120.8	-1245.2
CWD storage	640.8	1090.8	1731.6	-1016.6
PS storage	786.0	1337.7	2123.7	-1247.0
CWD NOC 1	537.6	915.2	1452.8	-786.6
CWD NOC 2	651.4	1108.8	1760.3	-1026.3
PS NOC 2	763.5	1299.6	2063.1	-1193.9
CWD Wheeling	655.0	1114.9	1769.9	-1034.1

B.1.4. Impacts on power stations and producers

Table B.8: Impacts on revenues of GB gas-fired power stations (SP, NPV, 2022-2031, £2018/19)

Tariff option	Power station type	Operational and carbon cost impact	Wholesale gas price impact	Gas tariff impact	Wholesale electricity price impact	Net revenue impact
SQ	NTS	0.0	0.0	0.0	0.0	0.0
	LDZ	0.0	0.0	0.0	0.0	0.0
CWD	NTS	-22.6	584.2	-465.4	-891.7	-795.5
	LDZ	0.0	56.0	3.6	-91.6	-32.0
PS	NTS	-25.2	509.6	-444.7	-1,131.1	-1,091.5
	LDZ	0.0	51.1	3.2	-114.1	-59.8
CWD storage	NTS	-24.5	623.0	-466.9	-920.8	-789.2
	LDZ	0.0	60.3	3.5	-95.8	-31.9
PS storage	NTS	-25.3	511.4	-444.5	-1,132.7	-1,091.1
	LDZ	0.0	51.3	3.1	-114.3	-59.9
CWD NOC 1	NTS	-31.9	436.9	23.3	-707.2	-278.9
	LDZ	0.0	47.0	0.6	-79.4	-31.7
CWD NOC 2	NTS	-26.3	554.9	-247.1	-929.9	-648.4
	LDZ	0.0	54.7	4.6	-96.4	-37.2
PS NOC 2	NTS	-28.1	397.8	-118.1	-1,083.7	-832.2
	LDZ	0.0	42.4	3.9	-110.2	-63.8
CWD wheeling	NTS	-25.8	556.6	-341.7	-937.1	-747.9
	LDZ	0.0	54.8	3.5	-97.0	-38.7

Table B.9: Impacts on revenues of producers and LNG terminals (SP, NPV, 2022-2031, £2018/19)

Tariff option	LNG terminals	Beach terminals	Onshore fields
SQ	0.0	0.0	0.0
CWD	-105.6	-1,819.2	-11.6
PS	-103.8	-332.3	-16.1
CWD storage	85.0	-1,974.9	-12.3
PS storage	-108.8	-267.6	-16.1
CWD NOC 1	123.0	-2,898.4	-6.0
CWD NOC 2	-16.2	-1,676.0	-7.3
PS NOC 2	44.7	-30.1	-8.6
CWD Wheeling	-80.4	-1,340.9	-7.4

Table B.10: Impacts on gas interconnectors (SP, NPV, 2022-2031, £2018/19)

Tariff option	Moffat	Continental IPs
SQ	0.0	0.0
CWD	67.6	-64.1
PS	67.5	-124.5
CWD storage	67.7	-68.6
PS storage	67.4	-124.7
CWD NOC 1	95.0	2.3
CWD NOC 2	66.0	-69.4
PS NOC 2	64.5	-116.3
CWD Wheeling	67.8	-97.2

Table B.11: Impacts on storage facilities (SP, NPV, 2022-2031, £2018/19)

Tariff option	Wholesale gas price impact	Gas tariff impact	Operational cost impact	Net revenue impact
SQ	0.0	0.0	0.0	0.0
CWD	3.3	-6.9	-2.0	-5.6
PS	28.5	-12.3	-7.0	9.3
CWD storage	5.4	-0.5	-5.0	-0.1
PS storage	32.5	-2.6	-10.5	19.5
CWD NOC 1	1.4	-7.4	-1.4	-7.4
CWD NOC 2	4.4	-6.8	-2.5	-4.9
PS NOC 2	27.9	-12.4	-6.6	8.9
CWD Wheeling	4.4	-6.8	-2.7	-5.1

B.1.5. Bypass analysis

Table B.12: Annual lost revenue by providing the NOC to routes that do not present a risk of profitable bypass of the NTS, and annual lost revenue from those routes that present a credible bypass risk in the absence of the NOC (SP, 2030-31, £18-19, assuming required payback time of five years)

Tariff option	Annual lost revenue by providing the NOC to routes that do not present a risk of profitable bypass of the NTS, £m	Annual lost revenue from those routes that present a credible bypass risk in the absence of the NOC, £m	
		Revenue lost as a result of bypass	Revenue lost as a result of providing the NOC discount
SQ	54.5	13.3	8.93
CWD NOC 1	39.9	0.0	20.45
CWD NOC 2	7.1	2.4	18.06
PS NOC 2	15.4	2.4	24.17
CWD Wheeling	0.2	30.1	13.97

B.2. Two degrees

B.2.1. Tariff impacts

We note that for GDN exit point tariffs we 'commoditise' the capacity element of the charge.[89]

For the status quo, we note that the 'weighted average capacity tariff' in these tables *includes* the commodity tariff, for comparability with the other tariff options. We also note that under the status quo, the commodity tariff is not paid at storage entry or exit points.[90]

All tariffs are presented in p/KWh (per day).

Table B.13: Annual weighted average tariffs at entry points under each option, including storage and interconnector entry tariffs (TD, 2022-23, £18/19)

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
Beach terminal				
SQ	0.005400	0.049000	0.067522	0.035052
SQ, no SH	0.005400	0.049000	0.062031	0.029620
CWD	0.027398	0.041919	0.055494	
PS	0.053605	0.000000	0.053605	
CWD Storage	0.027476	0.042032	0.055549	
PS Storage	0.053014	0.000000	0.053014	
CWD NOC 1	0.032774	0.050145	0.073155	
CWD NOC 2	0.028659	0.043844	0.059598	
PS NOC 2	0.058419	0.000000	0.058419	
CWD Wheeling	0.028342	0.043350	0.057270	

[89] Given that GDN bookings are assumed to be much higher than flows, 'commoditising' the capacity charge makes it appear larger. The ratio of GDN bookings to flows (in a given scenario and year) does not vary between tariff options, so this scaling up applies to all options equally.

[90] The commodity tariff is only levied on gas storage facility exit points for 'own use gas' which is a very small proportion of exit flows. We apply an exit commodity tariff of 0.06% to gas storage exit capacity which is consistent with this. This is what is shown in these data tables.

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
Onshore field				
SQ	0.000100	0.002800	0.035157	0.035052
SQ, no SH	0.000100	0.002800	0.029725	0.029620
CWD	0.026421	0.010505	0.032517	
PS	0.053605	0.000000	0.053605	
CWD Storage	0.026495	0.010535	0.032608	
PS Storage	0.053014	0.000000	0.053014	
CWD NOC 1	0.031605	0.012572	0.038166	
CWD NOC 2	0.027636	0.010989	0.033371	
PS NOC 2	0.058419	0.000000	0.058419	
CWD Wheeling	0.027330	0.010869	0.033002	
LNG importation terminal				
SQ	0.006800	0.016200	0.048293	0.035052
SQ, no SH	0.006800	0.016200	0.041535	0.029620
CWD	0.033767	0.017668	0.042601	
PS	0.053605	0.000000	0.053605	
CWD Storage	0.000814	0.000426	0.001027	
PS Storage	0.053014	0.000000	0.053014	
CWD NOC 1	0.040394	0.021138	0.050963	
CWD NOC 2	0.035320	0.018481	0.044560	
PS NOC 2	0.058419	0.000000	0.058419	
CWD Wheeling	0.034931	0.018274	0.044068	
Interconnector (Entry)				
SQ	0.017500	0.000000	0.052552	0.035052
SQ, no SH	0.017500	0.000000	0.062031	0.029620
CWD	0.029539	0.000000	0.029539	
PS	0.053605	0.000000	0.053605	
CWD Storage	0.029623	0.000000	0.029623	
PS Storage	0.053014	0.000000	0.053014	
CWD NOC 1	0.035334	0.000000	0.035334	
CWD NOC 2	0.030898	0.000000	0.030898	
PS NOC 2	0.058419	0.000000	0.058419	
CWD Wheeling	0.030557	0.000000	0.030557	
Storage site (Entry)				
SQ	0.000100	0.011400	0.004894	N/A
SQ, no SH	0.000100	0.011400	0.004880	N/A
CWD	0.013210	0.003799	0.016291	
PS	0.026802	0.000000	0.026802	
CWD Storage	0.005172	0.001487	0.006378	
PS Storage	0.010370	0.000000	0.010370	
CWD NOC 1	0.015803	0.004547	0.019489	
CWD NOC 2	0.013818	0.003974	0.017040	
PS NOC 2	0.029210	0.000000	0.029210	
CWD Wheeling	0.013665	0.003932	0.016853	

Note: For CWD Storage, the LMG tariff reflects the revenue recovery tariff component for existing contracts only (see Table 2.2), as these were sufficient to meet required capacity demand at these entry points for this modelled year under this option.

Table B.14: Annual weighted average tariffs at entry points under each option, including storage and interconnector entry tariffs (TD, 2026-27, £18/19)

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
Beach terminal				
SQ	0.002600	0.051400	0.070518	0.038851
SQ, no SH	0.002600	0.051400	0.064081	0.032363
CWD	0.024101	0.036916	0.043521	
PS	0.042242	0.000000	0.042242	
CWD Storage	0.024259	0.037153	0.043710	
PS Storage	0.042122	0.000000	0.042122	
CWD NOC 1	0.031289	0.047208	0.058515	
CWD NOC 2	0.028238	0.042605	0.050796	
PS NOC 2	0.049776	0.000000	0.049776	
CWD Wheeling	0.028107	0.042399	0.050129	
Onshore field				
SQ	0.000100	0.003000	0.038958	0.038851
SQ, no SH	0.000100	0.003000	0.032470	0.032363
CWD	0.023249	0.009209	0.028643	
PS	0.042242	0.000000	0.042242	
CWD Storage	0.023402	0.009270	0.028830	
PS Storage	0.042122	0.000000	0.042122	
CWD NOC 1	0.030090	0.012209	0.036461	
CWD NOC 2	0.027156	0.011013	0.032903	
PS NOC 2	0.049776	0.000000	0.049776	
CWD Wheeling	0.027029	0.010963	0.032750	
LNG importation terminal				
SQ	0.007600	0.015600	0.051688	0.038851
SQ, no SH	0.007600	0.015600	0.044321	0.032363
CWD	0.029730	0.015481	0.037470	
PS	0.042242	0.000000	0.042242	
CWD Storage	0.000914	0.000476	0.001152	
PS Storage	0.042122	0.000000	0.042122	
CWD NOC 1	0.038751	0.020103	0.048803	
CWD NOC 2	0.034971	0.018143	0.044042	
PS NOC 2	0.049776	0.000000	0.049776	
CWD Wheeling	0.034810	0.018057	0.043838	
Interconnector (Entry)				
SQ	0.019000	0.000000	0.057851	0.038851
SQ, no SH	0.019000	0.000000	0.064081	0.032363
CWD	0.026007	0.000000	0.026007	
PS	0.042242	0.000000	0.042242	
CWD Storage	0.026178	0.000000	0.026178	
PS Storage	0.042122	0.000000	0.042122	
CWD NOC 1	0.033847	0.000000	0.033847	
CWD NOC 2	0.030546	0.000000	0.030546	
PS NOC 2	0.049776	0.000000	0.049776	
CWD Wheeling	0.030405	0.000000	0.030405	

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
Storage site (Entry)				
SQ	0.000100	0.014200	0.005454	N/A
SQ, no SH	0.000100	0.014200	0.005453	N/A
CWD	0.011625	0.003321	0.013416	
PS	0.021121	0.000000	0.021121	
CWD Storage	0.004537	0.001297	0.005238	
PS Storage	0.008156	0.000000	0.008156	
CWD NOC 1	0.015045	0.004466	0.017274	
CWD NOC 2	0.013578	0.004029	0.015625	
PS NOC 2	0.024888	0.000000	0.024888	
CWD Wheeling	0.013514	0.004011	0.015572	

Note: For CWD Storage, the LMG tariff reflects the revenue recovery tariff component for existing contracts only (see Table 2.2), as these were sufficient to meet required capacity demand at these entry points for this modelled year under this option.

Table B.15: Annual weighted average tariffs at entry points under each option, including storage and interconnector entry tariffs (TD, 2030-31, £18/19)

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
Beach terminal				
SQ	0.000100	0.055500	0.075945	0.043546
CWD	0.023970	0.036558	0.040681	
PS	0.039810	0.000000	0.039810	
CWD Storage	0.024064	0.036696	0.040748	
PS Storage	0.039923	0.000000	0.039923	
CWD NOC 1	0.034703	0.052211	0.057484	
CWD NOC 2	0.031578	0.047512	0.050879	
PS NOC 2	0.049261	0.000000	0.049261	
CWD Wheeling	0.029763	0.044773	0.048964	
Onshore field				
SQ	0.000100	0.004000	0.043658	0.043546
CWD	0.023073	0.009628	0.028553	
PS	0.039810	0.000000	0.039810	
CWD Storage	0.023164	0.009666	0.028665	
PS Storage	0.039923	0.000000	0.039923	
CWD NOC 1	0.033290	0.014232	0.040717	
CWD NOC 2	0.030293	0.012945	0.037048	
PS NOC 2	0.049261	0.000000	0.049261	
CWD Wheeling	0.028550	0.012203	0.034987	
LNG importation terminal				
SQ	0.008200	0.015600	0.056991	0.043546
CWD	0.029866	0.015572	0.035197	
PS	0.039810	0.000000	0.039810	
CWD Storage	0.029984	0.015631	0.035141	
PS Storage	0.039923	0.000000	0.039923	
CWD NOC 1	0.043376	0.022708	0.049624	
CWD NOC 2	0.039469	0.020664	0.044997	
PS NOC 2	0.049261	0.000000	0.049261	
CWD Wheeling	0.037202	0.019474	0.043909	

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
Interconnector (Entry)				
SQ	0.024400	0.000000	0.067946	0.043546
CWD	0.026019	0.000000	0.026019	
PS	0.039810	0.000000	0.039810	
CWD Storage	0.026122	0.000000	0.026122	
PS Storage	0.039923	0.000000	0.039923	
CWD NOC 1	0.037719	0.000000	0.037719	
CWD NOC 2	0.034323	0.000000	0.034323	
PS NOC 2	0.049261	0.000000	0.049261	
CWD Wheeling	0.032351	0.000000	0.032351	
Storage site (Entry)				
SQ	0.000100	0.014200	0.005310	N/A
CWD	0.011537	0.003501	0.013349	
PS	0.019905	0.000000	0.019905	
CWD Storage	0.004477	0.001359	0.005181	
PS Storage	0.007694	0.000000	0.007694	
CWD NOC 1	0.016645	0.005247	0.019246	
CWD NOC 2	0.015146	0.004772	0.017542	
PS NOC 2	0.024630	0.000000	0.024630	
CWD Wheeling	0.014275	0.004499	0.016581	

Table B.16: Annual weighted average tariffs at exit points under each option, including storage and interconnector exit tariffs (TD, 2022-23, £18/19)

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
GDN				
SQ	0.000250	0.113409	0.056674	0.004787
CWD	0.032964	0.051939	0.051596	
PS	0.051786	0.000000	0.051786	
CWD Storage	0.033014	0.051858	0.051601	
PS Storage	0.051779	0.000000	0.051779	
CWD NOC 1	0.034070	0.054801	0.053887	
CWD NOC 2	0.033377	0.052293	0.052151	
PS NOC 2	0.052320	0.000000	0.052320	
CWD Wheeling	0.033551	0.052863	0.052508	
Industrial				
SQ	0.000100	0.041200	0.014758	0.004787
CWD	0.013344	0.018747	0.015372	
PS	0.020686	0.000000	0.020686	
CWD Storage	0.013359	0.018715	0.015422	
PS Storage	0.020682	0.000000	0.020682	
CWD NOC 1	0.013785	0.019740	0.019970	
CWD NOC 2	0.013508	0.018870	0.015807	
PS NOC 2	0.020899	0.000000	0.020899	
CWD Wheeling	0.013580	0.019080	0.015689	

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
Power station				
SQ	0.000100	0.045300	0.023959	0.004787
CWD	0.013191	0.020722	0.021589	
PS	0.020686	0.000000	0.020686	
CWD Storage	0.013206	0.020695	0.021578	
PS Storage	0.020682	0.000000	0.020682	
CWD NOC 1	0.014440	0.021059	0.025160	
CWD NOC 2	0.013354	0.020866	0.022277	
PS NOC 2	0.020899	0.000000	0.020899	
CWD Wheeling	0.013425	0.021092	0.022099	
Interconnector (Exit)				
SQ	0.002900	0.003800	0.007687	0.004787
CWD	0.016306	0.000000	0.016306	
PS	0.020686	0.000000	0.020686	
CWD Storage	0.016427	0.000000	0.016427	
PS Storage	0.020682	0.000000	0.020682	
CWD NOC 1	0.018123	0.001037	0.018123	
CWD NOC 2	0.016546	0.002775	0.016546	
PS NOC 2	0.020899	0.000000	0.020899	
CWD Wheeling	0.000831	0.000000	0.000831	
Storage site (Exit)				
SQ	0.012700	0.026000	0.032365	0.000003
CWD	0.007151	0.005732	0.011667	
PS	0.010343	0.000000	0.010343	
CWD Storage	0.002818	0.002246	0.004621	
PS Storage	0.004072	0.000000	0.004072	
CWD NOC 1	0.007409	0.005934	0.012069	
CWD NOC 2	0.007238	0.005769	0.011776	
PS NOC 2	0.010449	0.000000	0.010449	
CWD Wheeling	0.007278	0.005828	0.011862	

Table B.17: Annual weighted average tariffs at exit points under each option, including storage and interconnector exit tariffs (TD, 2026-27, £18/19)

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
GDN				
SQ	0.000242	0.111045	0.058925	0.007472
CWD	0.033516	0.052808	0.052452	
PS	0.052677	0.000000	0.052677	
CWD Storage	0.033567	0.052727	0.052458	
PS Storage	0.052669	0.000000	0.052669	
CWD NOC 1	0.035717	0.056963	0.056403	
CWD NOC 2	0.035065	0.054837	0.054834	
PS NOC 2	0.054494	0.000000	0.054494	
CWD Wheeling	0.035305	0.055424	0.055248	

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
Industrial				
SQ	0.000100	0.042500	0.018967	0.007472
CWD	0.014040	0.019724	0.016173	
PS	0.021774	0.000000	0.021774	
CWD Storage	0.014056	0.019690	0.016226	
PS Storage	0.021771	0.000000	0.021771	
CWD NOC 1	0.014955	0.021203	0.022051	
CWD NOC 2	0.014676	0.020450	0.017436	
PS NOC 2	0.022525	0.000000	0.022525	
CWD Wheeling	0.014776	0.020678	0.017344	
Power station				
SQ	0.000100	0.045900	0.026661	0.007472
CWD	0.013879	0.021803	0.022733	
PS	0.021774	0.000000	0.021774	
CWD Storage	0.013895	0.021774	0.022721	
PS Storage	0.021771	0.000000	0.021771	
CWD NOC 1	0.016002	0.022306	0.026701	
CWD NOC 2	0.014507	0.022653	0.023376	
PS NOC 2	0.022525	0.000000	0.022525	
CWD Wheeling	0.014606	0.022896	0.023865	
Interconnector (Exit)				
SQ	0.007300	0.003300	0.018071	0.007472
CWD	0.017156	0.000000	0.017156	
PS	0.021774	0.000000	0.021774	
CWD Storage	0.017283	0.000000	0.017283	
PS Storage	0.021771	0.000000	0.021771	
CWD NOC 1	0.020176	0.000648	0.020176	
CWD NOC 2	0.018766	0.000000	0.018766	
PS NOC 2	0.022525	0.000000	0.022525	
CWD Wheeling	0.000942	0.000000	0.000942	
Storage site (Exit)				
SQ	0.013300	0.026000	0.030720	0.000004
CWD	0.007524	0.006030	0.012275	
PS	0.010887	0.000000	0.010887	
CWD Storage	0.002963	0.002361	0.004859	
PS Storage	0.004283	0.000000	0.004283	
CWD NOC 1	0.008079	0.006270	0.012775	
CWD NOC 2	0.007908	0.006124	0.012545	
PS NOC 2	0.011263	0.000000	0.011263	
CWD Wheeling	0.007962	0.006188	0.012685	

Table B.18: Annual weighted average tariffs at exit points under each option, including storage and interconnector exit tariffs (TD, 2030-31, £18/19)

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
GDN				
SQ	0.000241	0.113873	0.065345	0.009991
CWD	0.036272	0.057151	0.056381	
PS	0.056671	0.000000	0.056671	
CWD Storage	0.036325	0.057059	0.056389	
PS Storage	0.056662	0.000000	0.056662	
CWD NOC 1	0.039499	0.065246	0.063453	
CWD NOC 2	0.038003	0.063258	0.061049	
PS NOC 2	0.060532	0.000000	0.060532	
CWD Wheeling	0.038807	0.062756	0.061460	
Industrial				
SQ	0.000100	0.043800	0.023318	0.009991
CWD	0.015237	0.021405	0.017552	
PS	0.023490	0.000000	0.023490	
CWD Storage	0.015253	0.021368	0.017608	
PS Storage	0.023486	0.000000	0.023486	
CWD NOC 1	0.016597	0.024298	0.026083	
CWD NOC 2	0.015966	0.023603	0.019666	
PS NOC 2	0.025090	0.000000	0.025090	
CWD Wheeling	0.016293	0.023471	0.019499	
Power station				
SQ	0.000100	0.047200	0.030188	0.009991
CWD	0.015062	0.023661	0.024668	
PS	0.023490	0.000000	0.023490	
CWD Storage	0.015079	0.023629	0.024654	
PS Storage	0.023486	0.000000	0.023486	
CWD NOC 1	0.017998	0.025419	0.029187	
CWD NOC 2	0.015773	0.026199	0.025945	
PS NOC 2	0.025090	0.000000	0.025090	
CWD Wheeling	0.016102	0.025995	0.026653	
Interconnector (Exit)				
SQ	0.015000	0.000000	0.024991	0.009991
CWD	0.018619	0.000000	0.018619	
PS	0.023490	0.000000	0.023490	
CWD Storage	0.018755	0.000000	0.018755	
PS Storage	0.023486	0.000000	0.023486	
CWD NOC 1	0.024224	0.000000	0.024224	
CWD NOC 2	0.022731	0.000000	0.022731	
PS NOC 2	0.025090	0.000000	0.025090	
CWD Wheeling	0.001080	0.000000	0.001080	

Tariff option	Minimum capacity tariff	Capacity tariff range	Weighted average capacity tariff	TO Commodity tariff
Storage site (Exit)				
SQ	0.014500	0.026100	0.033908	0.000006
CWD	0.008165	0.006544	0.013321	
PS	0.011745	0.000000	0.011745	
CWD Storage	0.003212	0.002560	0.005267	
PS Storage	0.004616	0.000000	0.004616	
CWD NOC 1	0.009081	0.007020	0.014503	
CWD NOC 2	0.008730	0.006850	0.014035	
PS NOC 2	0.012545	0.000000	0.012545	
CWD Wheeling	0.008873	0.006945	0.014261	

B.2.2. Gas and electricity market price impacts

Table B.19: Simulated gas and electricity prices (TD, £18/19)

Tariff option	Wholesale gas price, £/MWh	Wholesale electricity price, £/MWh
2022-23 modelled year		
SQ	17.07	56.85
CWD	16.89	56.23
PS	16.91	55.98
CWD storage	16.77	56.13
PS storage	16.91	55.98
CWD NOC 1	17.03	56.52
CWD NOC 2	16.94	56.29
PS NOC 2	16.99	56.09
CWD Wheeling	16.91	56.23
2026-27 modelled year		
SQ	17.30	66.83
CWD	17.08	66.11
PS	17.11	65.87
CWD storage	16.96	66.01
PS storage	17.10	65.86
CWD NOC 1	17.22	66.40
CWD NOC 2	17.18	66.29
PS NOC 2	17.24	66.08
CWD Wheeling	17.15	66.22
2030-31 modelled year		
SQ	15.20	64.79
CWD	14.99	64.07
PS	14.97	63.71
CWD storage	14.95	64.13
PS storage	14.97	63.73
CWD NOC 1	15.19	64.50
CWD NOC 2	15.12	64.32
PS NOC 2	15.07	63.87
CWD Wheeling	15.09	64.25

B.2.3. Consumer welfare

Tariff option	Wholesale gas price impact - residential & I&C consumers				Gas tariff impacts - residential & I&C consumers				Power stations		Net impact
	Domestic consumers	LDZ-connected I&C consumers	NTS-connected I&C consumers	Total	Domestic consumers	LDZ-connected I&C consumers	NTS-connected I&C consumers	Total	Wholesale gas price impact	Gas tariff impacts	
SQ	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CWD	476.9	295.0	35.0	806.8	100.6	62.8	6.2	169.6	435.4	-542.9	868.9
PS	449.0	278.5	33.8	761.3	95.3	59.5	-3.2	151.6	435.9	-526.5	822.3
CWD storage	694.8	427.8	49.5	1172.1	100.5	62.7	6.1	169.3	646.6	-634.8	1353.2
PS storage	455.7	282.4	34.1	772.1	95.5	59.6	-3.2	151.9	441.8	-526.5	839.3
CWD NOC 1	110.9	68.6	7.2	186.7	1.5	0.7	17.4	19.7	54.1	81.1	341.6
CWD NOC 2	252.3	154.5	17.6	424.4	44.0	27.0	9.0	79.9	224.0	-237.9	490.4
PS NOC 2	198.7	123.0	15.6	337.3	49.4	30.5	6.3	86.1	195.1	-139.2	479.3
CWD Wheeling	320.2	196.3	22.6	539.1	34.9	21.4	4.9	61.2	289.3	-418.9	470.7

Tariff option	Wholesale electricity price impact - residential & I&C consumers			Wholesale electricity price impact - power stations
	Domestic consumers	I&C consumers	Total	
SQ	0.0	0.0	0.0	0.0
CWD	522.3	958.0	1480.3	-736.7
PS	736.4	1351.0	2087.3	-1004.7
CWD storage	558.8	1023.1	1581.9	-773.6
PS storage	737.3	1352.4	2089.7	-1009.5
CWD NOC 1	267.3	489.6	756.9	-352.1
CWD NOC 2	396.8	725.3	1122.1	-584.6
PS NOC 2	611.1	1120.3	1731.4	-830.0
CWD Wheeling	444.8	813.5	1258.4	-650.7

B.2.4. Impacts on power stations, and producers

Table B.20: Impacts on revenues of GB gas-fired power stations (TD, NPV, 2022-2031, £2018/19)

Tariff option	Power station type	Operational and carbon cost impact	Wholesale gas price impact	Gas tariff impact	Wholesale electricity price impact	Net revenue impact
SQ	NTS	0.0	0.0	0.0	0.0	0.0
	LDZ	0.0	0.0	0.0	0.0	0.0
CWD	NTS	-23.1	401.7	-550.0	-671.8	-843.2
	LDZ	0.0	33.6	7.1	-64.9	-24.1
PS	NTS	-34.5	401.0	-533.2	-915.8	-1,082.5
	LDZ	0.0	34.9	6.8	-88.9	-47.2
CWD storage	NTS	-32.7	597.1	-642.0	-703.6	-781.1
	LDZ	0.0	49.5	7.1	-70.0	-13.3
PS storage	NTS	-34.5	406.5	-533.3	-920.2	-1,081.5
	LDZ	0.0	35.3	6.8	-89.3	-47.2
CWD NOC 1	NTS	-26.0	47.4	81.0	-317.8	-215.3
	LDZ	0.0	6.7	0.1	-34.3	-27.5
CWD NOC 2	NTS	-12.7	206.5	-241.0	-534.6	-581.8
	LDZ	0.0	17.4	3.1	-50.0	-29.4
PS NOC 2	NTS	-29.6	177.7	-142.7	-756.5	-751.2
	LDZ	0.0	17.5	3.5	-73.5	-52.5
CWD wheeling	NTS	-15.2	266.9	-421.4	-594.7	-764.4
	LDZ	0.0	22.4	2.5	-56.0	-31.1

Table B.21: Impacts on revenues of producers and LNG terminals (TD, NPV, 2022-2031, £2018/19)

Tariff option	LNG terminals	Beach terminals	Onshore fields
SQ	0.0	0.0	0.0
CWD	-715.5	-770.6	-8.9
PS	-1,337.0	509.8	-14.2
CWD storage	-348.7	-1,456.8	-12.0
PS storage	-1,339.4	532.1	-14.2
CWD NOC 1	381.1	-5,437.0	-0.7
CWD NOC 2	-147.4	-2,126.5	-2.8
PS NOC 2	-805.4	382.8	-5.9
CWD Wheeling	-526.5	-870.0	-4.1

Table B.22: Impacts on gas interconnectors (TD, NPV, 2022-2031, £2018/19)

Tariff option	Moffat	Continental IPs
SQ	0.0	0.0
CWD	120.0	78.1
PS	120.0	47.7
CWD storage	122.7	55.6
PS storage	120.0	46.7
CWD NOC 1	137.8	367.9
CWD NOC 2	117.4	168.8
PS NOC 2	113.9	54.6
CWD Wheeling	120.0	51.3

Table B.23: Impacts on storage facilities (TD, NPV, 2022-2031, £2018/19)

Tariff option	Wholesale gas price impact	Gas tariff impact	Operational cost impact	Net revenue impact
SQ	0.0	0.0	0.0	0.0
CWD	-1.5	-6.1	-1.4	-9.0
PS	15.9	-11.5	-3.2	1.2
CWD storage	9.4	0.1	-3.0	6.5
PS storage	19.6	-1.9	-5.1	12.6
CWD NOC 1	-15.5	-8.7	2.6	-21.6
CWD NOC 2	-6.5	-7.8	0.5	-13.8
PS NOC 2	15.8	-14.3	-1.7	-0.1
CWD Wheeling	-4.9	-7.6	-0.3	-12.8

B.2.5. Bypass analysis

Table B.24: Annual lost revenue by providing the NOC to routes that do not present a risk of profitable bypass of the NTS, and annual lost revenue from those routes that present a credible bypass risk in the absence of the NOC (TD, 2030-31, £18-19, assuming required payback time of five years)

Tariff option	Annual lost revenue by providing the NOC to routes that do not present a risk of profitable bypass of the NTS, £m	Annual lost revenue from those routes that present a credible bypass risk in the absence of the NOC, £m	
		Revenue lost as a result of bypass	Revenue lost as a result of providing the NOC discount
SQ	74.4	10.8	15.26
CWD NOC 1	52.3	0.0	42.51
CWD NOC 2	9.6	2.3	28.79
PS NOC 2	21.3	2.3	30.73
CWD Wheeling	0.4	29.4	16.34

Appendix C DESCRIPTION OF GAS AND ELECTRICITY MARKET MODELS

The current gas market model covers all existing (2018) gas consumption and production regions, including:

- main producing countries, such as Russia and Qatar are explicitly represented in the model as separate supply 'nodes';
- other producers are aggregated into regions (e.g. North America includes the USA, Canada and Mexico); and
- other demand centres are aggregated to the regional level, such as the Middle East or JKT (Japan, South Korea & Taiwan).

C.1. TIME RESOLUTION

The model solves for **daily** flows and prices.

C.2. GAS SUPPLY CHAIN

The model covers the entire supply chain down to the transmission level (i.e., distribution level is not considered). It represents production, demand, transit routes, LNG facilities, and gas storage sites.

The model includes all main entry and exit points to the GB gas transmission network:

- UKCS only beach terminals;
- UKCS + Norway flows at Easington & St Fergus;
- LNG terminals;
- GB storage facilities modelled at individual level;
- bi-directional interconnection to Europe;
- one-directional exit only interconnection to Ireland; and
- domestic consumption (both domestic and industrial & commercial consumers).

For the purposes of the modelling for the analysis presented in this report, the model was extended to include multiple nodes representing individual power stations who made use of the OCC product within the gas year 2017-18.

C.3. EU CROSS-BORDER TRANSMISSION CAPACITIES & TARIFFS

The model incorporated cross-border transmission capacity to those countries to which GB is connected. The markets in each of those regions were represented in the model in order to determine cross-border gas prices.

C.4. STORAGE CAPACITIES & COSTS

With the exception of GB, all existing storage sites were aggregated to country level (i.e., each country/market area has one storage 'node'). However, we do differentiate between types of storage – depleted fields, aquifers and salt caverns – as this influences their deliverability rate (e.g., depleted field storage sites are seasonal storage hence withdrawal rates are much lower than withdrawal rates of salt cavern storage sites). Marginal cost of different types of storage is based on public information & calibration processes.

C.5. LNG market

LNG Shipping routes are 'pre-specified' in the model as a network (nodes-arcs). We then apply average shipping tariff rates and consider number of days it takes to sail from one point to another, assuming an average LNG shipping speed (e.g., 19 knot/hour). We take total stock of LNG as aggregate shipping capacity; this aggregate shipping capacity is then applied to every route.

C.6. Price setting and modelling objective

Model objective

Given assumed marginal costs of gas production, transport and storage, the model objective is to **maximise social welfare (minimize total cost) while meeting various constraints:**

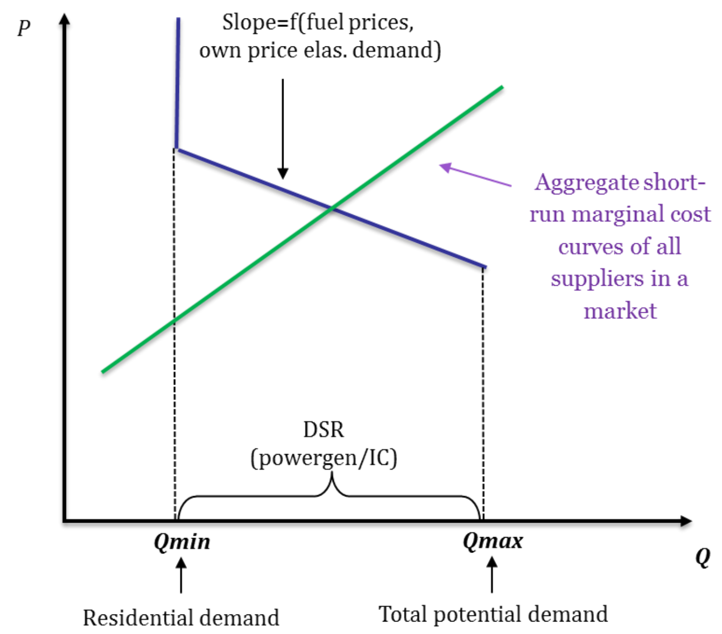
- Production capacities;
- Transmission (entry/exit) capacities;
- LNG liquefaction & LNG send-out capacities;
- Conventional underground storage;
- LNG storage injection, withdrawal & max working volume capacities; and
- Daily *Qmin* demand while not violating *Qmax* demand constraints (Figure C.1).

Demand curves

Our demand curves consider short-term demand side response. The slope of the demand curves for each European gas market depends on own price elasticity of demand – **determined by running a separate Pan-European electricity dispatch model (see Box 1) to account for possible inter-fuel competition and evolving market structure in the power generation sector in Europe.**

They also depend on commonly defined scenarios for input fuel prices for power stations as well as carbon and other costs that determine merit order of each individual market areas as well as cross-border flows.

Figure C.1: Wholesale gas price setting in the model



Box 1: North-west European electricity dispatch model used to derive wholesale gas demand curves

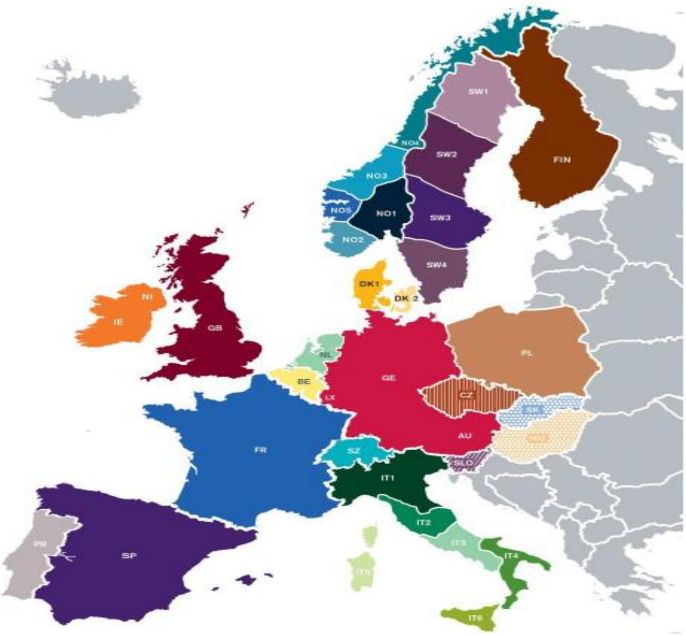
Pan-European (NWE) electricity market model

- All existing generation assets aggregated up to technology level (e.g., CCGT, OCGT, IC etc.).
- 'Copper plate' model for each bidding area, assumes complete market coupling for cross-border trade taking into account.
- Models day-ahead energy only as well as operating reserve requirement.
- Takes into account main techno-economic constraints such as ramp rates.

Time Resolution – Day-ahead hourly market

- We run the model for 8760 time periods (hours) or 1 year.

Used with gas models to ensure consistency in scenarios



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