UNC728 – Analytical support

Ofgem

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FINAL REPORT

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1. INTRODUCTION

Ofgem commissioned CEPA to conduct analysis of the costs and benefits of the UNC0728 modification proposal. This report sets out CEPA's quantitative assessment of impacts.

NGG levies network charges in accordance with the NTS charging methodology contained within the Uniform Network Code (UNC). Under current arrangements, network users pay for the 'right' to flow gas onto (entry) and off (exit) the NTS. Entry and exit rights are purchased separately. Following Ofgem's approval of UNC0678A, reserve prices are derived from a reference price which is determined using a postage stamp methodology (RPM). Approval of UNC0678A also removed the optional commodity charge (OCC) from the GB gas transmission tariff arrangements.

UNC0728 and alternatives UNC0728A – UNC0728D seek to introduce a new form of OCC into the gas transmission tariff structures. The options differ in several ways from the previous OCC and differ from each other in several ways.

In this report, we set out our quantitative analysis of UNC0728. 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 our analysis of the 'first order effects' of the options, i.e. their direct impact on tariffs and consumer welfare. Importantly, this analysis assumes that users remain on the gas system and do not choose to bypass.
- In **Section 4**, we incorporate analysis which considers the possibility that users may choose to build bypass pipelines and no longer contribute towards revenue recovery on the NTS. We consider the impact that this could have on tariffs and welfare.
- We provide charts and tables showing the full set of results in **Appendix A**.
- In **Appendix B**, we provide a more detailed description of the gas and electricity market models used for the analysis.

2. METHODOLOGY

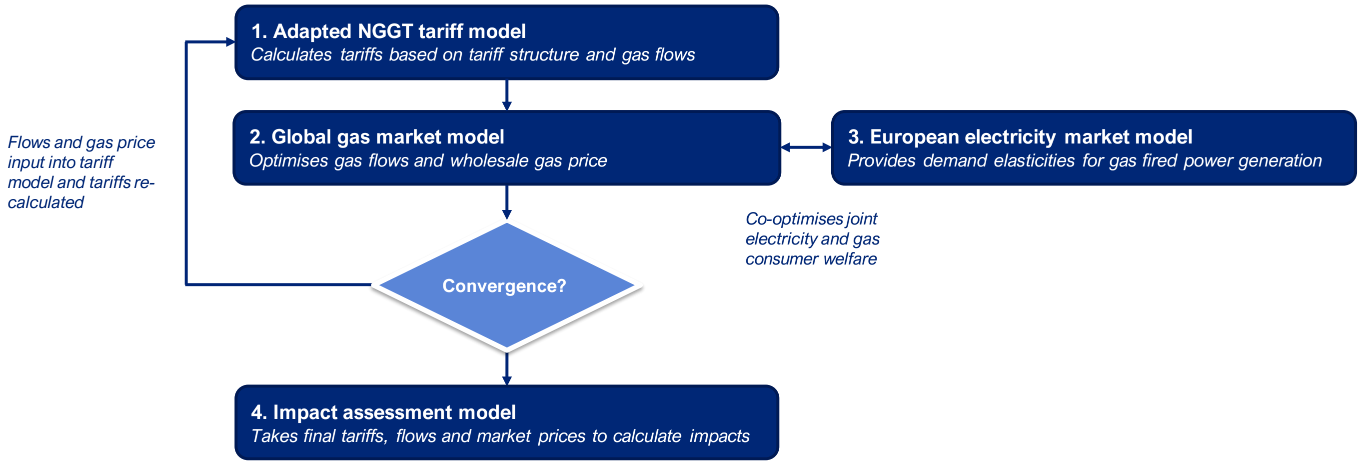
In this section, we summarise our modelling approach for analysing modification UNC0728 and alternatives. We also set out the key assumptions used in our modelling and their potential impacts on results.

2.1. OVERVIEW OF MODELLING APPROACH

We use four interacting models to consider the range of impacts of UNC0728 and its alternatives. These are:

1. **A gas transmission tariff model**: Originally designed by NGGT for UNC0678 and adapted by us, used to calculate changes in tariffs at each entry and exit point under each option.
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 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[2] 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. To incorporate impacts of 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 estimate 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,[3] 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

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

[3] 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.[4]

Gas years and scenarios

To understand impacts in the short and medium term, we select three gas years in which we model the modifications. We also choose two scenarios from National Grid's 2020 Future Energy Scenarios (FES)[5] 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 used:

Table 2.1: Gas years modelled

Gas years	Key features
2022/23	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.

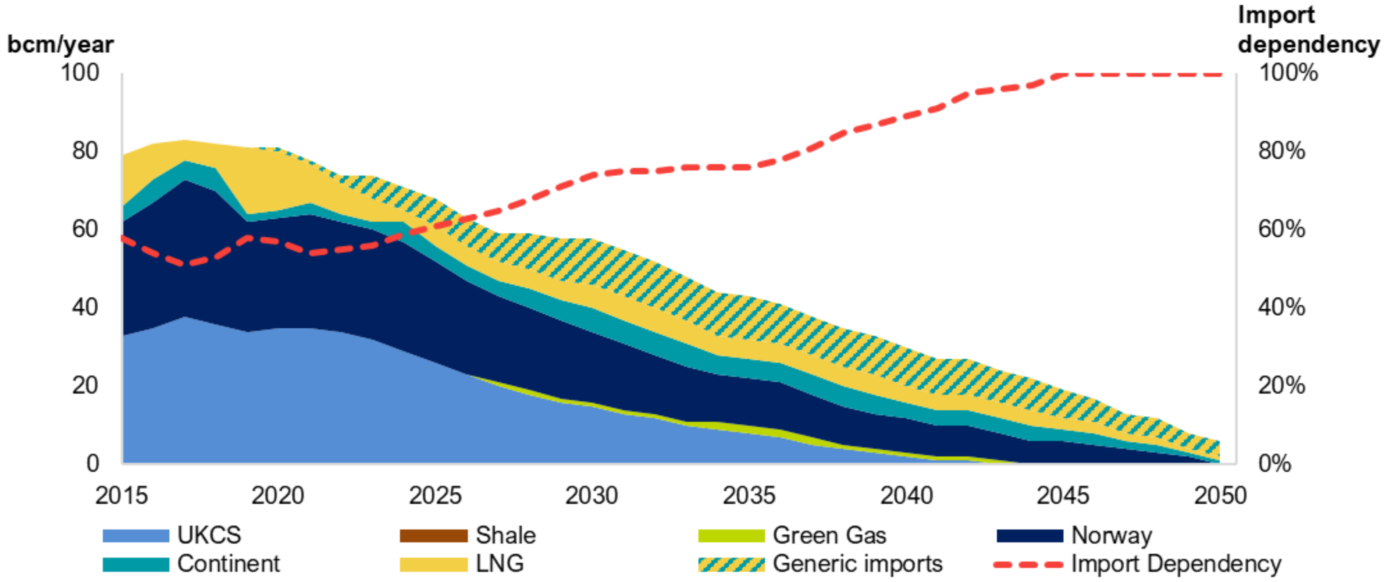
We use the Consumer Transformation (CT) as our core FES scenario for analysis. CT provides a scenario which achieves net zero decarbonisation objectives and through a more decentralised electricity system. The CT scenario observes sustained reduction in gas demand and supply as there is greater ambition for energy efficiency and to move away from gas-fired power generation.

We test impacts under a sensitivity scenario in which gas use remains high. We use National Grid's Steady Progression (SP) scenario for this. Net zero decarbonisation targets are not achieved under SP and the electricity system remains more centralised with more gas-fired power generation. Under SP, gas demand initially declines slightly with the lowest demand observed around 2030. 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.

[4] 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. Using this rule, convergence in tariffs was achieved for all charging options, spot years, and scenarios modelled.

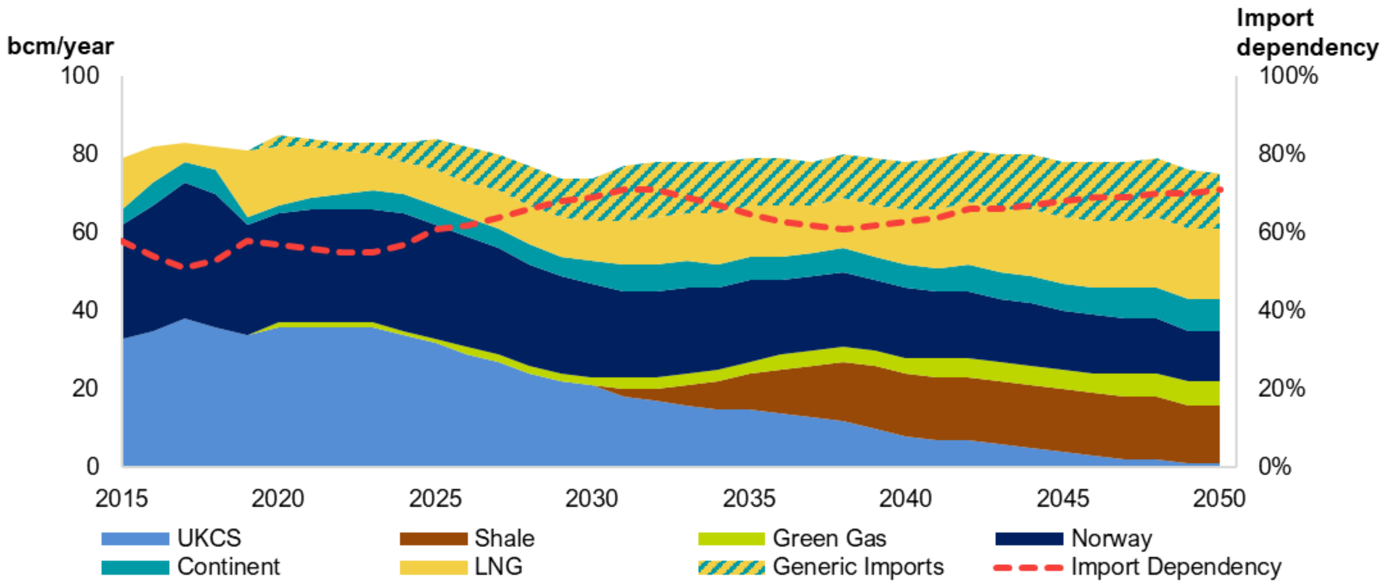
[5] To incorporate EU and global commodity data, we combine the FES scenarios with the World Energy Outlook (WEO, 2019) scenarios and ENTSO-E (TYNDP 2020) scenarios. We map the WEO Sustainable Development scenario and ENTSO-E Distributed Energy scenarios to FES CT and map WEO Stated Policies and ENTSO-E National Trends to FES SP. WEO 2020 scenarios were not published in time to incorporate them into our analysis.

Figure 2.2: Gas supply under FES Consumer Transformation (CT)



Source: National Grid, FES 2020.

Figure 2.3: Gas supply under FES Steady Progression (SP)



Source: National Grid, FES 2020.

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 CT scenario sets out a pathway in which these 2050 targets are met while they are not achieved under SP. We therefore use CT as a central scenario in which gas supply falls in line with these targets. SP is used as a sensitivity in which gas use remains high. Given the proximity of the first spot year 2022/23 to the present, we model a single central case scenario for 2022/23 based on our central CT scenario. Following this, the two scenarios diverge and we interpolate based on modelling of spot years 2026/27 and 2030/31 for each scenario independently.

Our analysis in this report focuses on outcomes under the CT scenario. We present the full range of results, including those observed under the SP sensitivity in Appendix A.

The counterfactual

Ofgem approved modification UNC0678A on 28 May 2020[6] and this modification was implemented on 1 October 2020 (the start of the gas year). UNC0678A introduced a 'postage stamp' reference price mechanism for setting entry and exit transmission tariffs. It also removed the pre-existing optional commodity charge (OCC), a shorthaul product which existed in the previous regime. We take UNC0678A as the counterfactual 'status quo' option against which the UNC0728 modification options are compared.

Modification options

Under UNC0728, the postage stamp arrangements that Ofgem approved under UNC0678A would remain in place. However, a shorthaul product would become available for exit point offtakers who meet the eligibility criteria, based on the distance from the exit point to a nominated entry point.[7]

For those users with a nominated entry point with a straight-line distance of less than a maximum threshold distance, a shorthaul product would be available which would provide a discount on the standard firm tariff product. Across modification alternatives, the minimum discount available on a firm transmission services tariff is 10% and the maximum is 90%, with the exact discount offered for a given shorthaul route determined by the route's distance. For non-transmission services commodity tariffs, some alternatives propose no discount, while others propose discounts ranging from 80-94%.

No discounts are proposed for any interruptible/off-peak capacity bookings (or flows associated with these). Existing contracts can be used at the nominated entry point without affecting the shorthaul discounts received at exit. However, where existing contracts are used, the shorthaul discount on the non-transmission services entry tariff would be lost (under options UNC0728A and UNC0728D only).

The modification alternatives differ in four respects:

1. The maximum distance from the exit point to the nominated entry point within which a user is eligible for the shorthaul product.
2. The relationship between this distance and the size of the discount on the Transmission Services Charge.[8]
3. Whether or not the product also provides a discount on the Non-Transmission Services Charge.[9] Where this is the case, the discount on this element is constant across all eligible users – there is no change in the discount as the route distance varies.
4. Whether the Transmission Services discount applies to 'Flows' or 'Bookings'. In practice, where applied to 'Flows', this means that shorthaul capacity that is booked but not nominated must pay the standard firm capacity tariff. Whereas where applied to 'Bookings', shorthaul capacity continues to pay the discounted shorthaul tariff whether or not it is nominated.

Our modelling encompasses routes that may be eligible for the shorthaul product up to the maximum route distance of 28 km under UNC0728B. We engaged closely with NGG and with Ofgem to agree the entry and exit point combinations that should be included in this analysis. In total, this engagement identified 24 eligible routes with a route distance of less than 18 km which would be eligible for the shorthaul product under UNC0728, UNC0728A and UNC0728C. The majority of these routes had route distances of less than 5 km such that narrowing

[6] See: https://www.ofgem.gov.uk/system/files/docs/2020/05/unc678_-_decision_0.pdf

[7] The eligibility criteria depends on the straight-line distance from entry to exit point as calculated by NGG (to the nearest 0.1 km) as the minimum of each of the distances between each 'System Entry Point' within the nominated entry point and the exit point, using six figure grid references.

[8] The Transmission Services Charge is a 'capacity-based charge', i.e. it is charged to network users based on their booked capacity.

[9] The Non-Transmission Services Charge is a 'commodity-based charge', i.e. it is charged to network users based on their gas flows using the NTS.

eligibility under UNC0728D only reduced the number of eligible routes by two (to 22 in total). Broadening the eligible route distance to 28 km under UNC0728B increased the number of eligible routes to 32.

We summarise UNC0728 and the alternatives put forward in the table below.

Table 2.2: Characteristics of modelled option

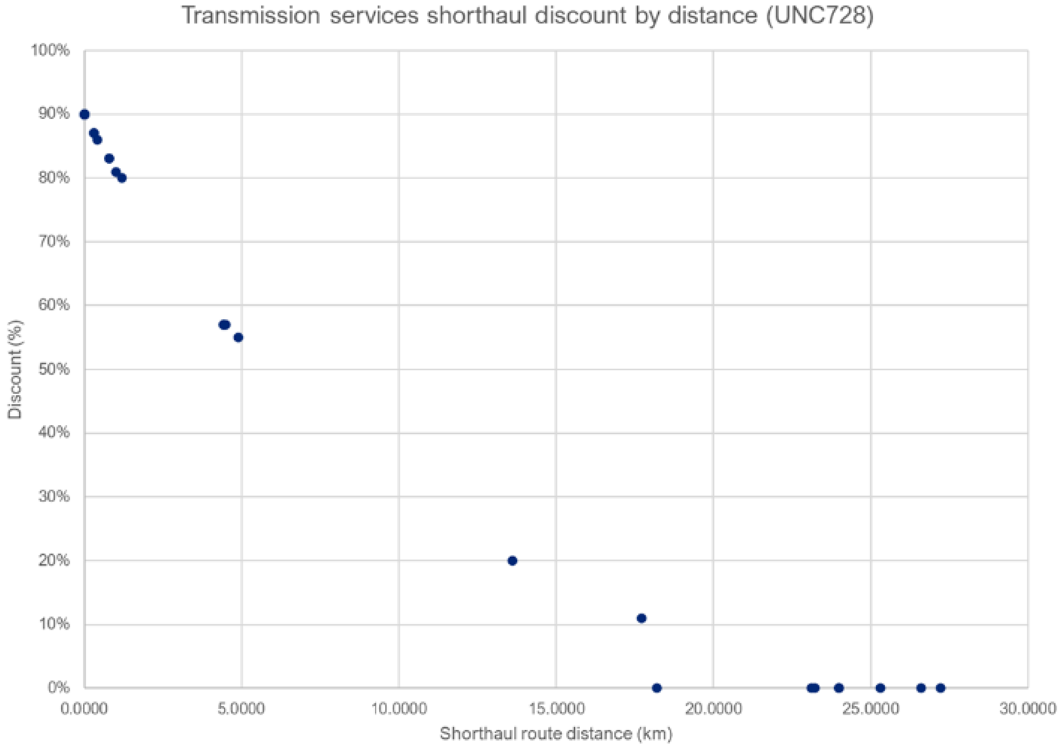
	UNC0728	UNC0728A	UNC0728B	UNC0728C	UNC0728D
Maximum eligibility distance	18 km	18 km	28 km	18 km	5 km
Discount applies to:	Flows	Flows	Flows	Bookings	Flows
Charges which the discount is applied to	Transmission Services Charge	Transmission Services Charge and Non-Transmission Services Charge	Transmission Services Charge	Transmission Services Charge	Transmission Services Charge and Non-Transmission Services Charge
Non-transmission services charge discount	N/A	80%	N/A	N/A	94%
Number of eligible routes included in modelling	24	24	32	24	22

Source: Adapted by CEPA, based on NGG

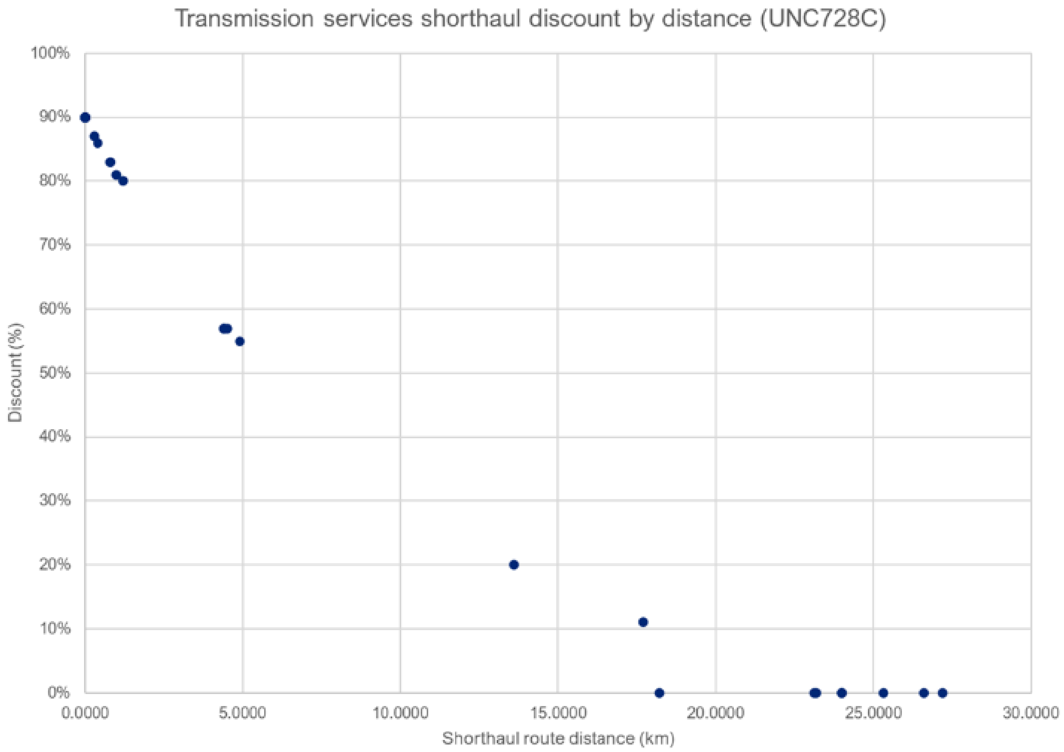
It is important to note that the impact of each of these routes on tariffs, gas prices and consumer welfare are very unequal due to the significant differences in flows and hence, the corresponding capacity bookings. It should therefore not be expected that impacts are proportional to the number of eligible routes. A single route with significant capacity bookings can have a disproportionate impact on modelled outcomes, depending on whether it is or isn't eligible under the relevant option.

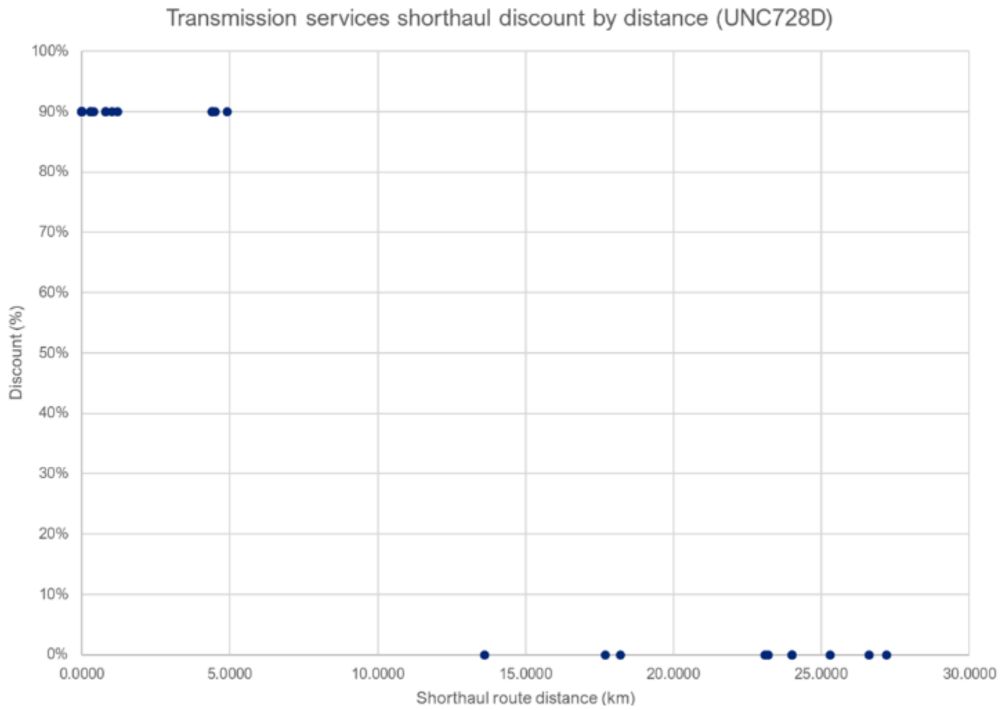
We summarise the relationship between the route distance and the percentage discount for those routes that we included within our modelling in Figure 2.4.

Figure 2.4: Relationship between route distance and Transmission Services Discount under UNC0728 and variants




Transmission services shorthaul discount by distance (UNC728B)
Discount (%)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0.0000
5.0000
10.0000
15.0000
20.0000
25.0000
30.0000
Shorthaul route distance (km)


Transmission services shorthaul discount by distance (UNC728C)
Discount (%)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0.0000
5.0000
10.0000
15.0000
20.0000
25.0000
30.0000
Shorthaul route distance (km)



Analysis of UNC0728C

UNC0728C is identical to UNC0728 in all aspects other than the application of the discount to 'Bookings' rather than 'Flows'. In practice, we might expect UNC0728C to reduce an element of risk aversion that shorthaul shippers may have. They can book shorthaul capacity in the knowledge that any excess shorthaul capacity continues to face the discounted charge rather than the fully firm tariff. Given the spare capacity on the system, and the ability to book shorthaul capacity using all firm products (e.g. daily and within-day), we would expect shorthaul shippers to be able to profile their shorthaul capacity bookings close to actual flows such that over-bookings of shorthaul capacity are small. This leads us to assume that the outcomes under UNC0728 and UNC0728C would be similar, particularly within our modelling framework.

For this reason, we do not differentiate the analysis of UNC0728C and UNC0728 within our core modelling framework. However, we do carry out a sensitivity in which we test the impacts on tariffs of shorthaul and non-shorthaul users, assuming a degree of over-booking of capacity under UNC0728C (Section 3.6).

2.1.1. Tariff modelling

We have used the Microsoft Excel tariff models developed by National Grid for the purposes of modelling the impacts of the modification proposals at each Entry and Exit point.[10] 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 extended the tool to include modelling of the non-transmission services tariffs.
- We included functionality to reflect the shorthaul discount methodologies,[11] their revenue recovery implications, and the impact on the tariffs.
- We added more granularity to the modelling of existing contracts, to reflect that these can be used for on shorthaul routes. To do this, we utilised confidential existing contract data shared by NGGT that allowed us

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

[11] As captured by NGGT in the tool developed under UNC0728. See: UNC0728 - Estimated Transmission Cost Calculator.

to compare individual contract prices with entry tariffs (including the discounted tariffs for nominated entry points on shorthaul routes) to determine whether these would be used preferentially or not.

Key assumptions

To make modelling of UNC0728 possible, we incorporated several necessary assumptions and abstractions. We summarise the key assumptions in the following table.

Table 2.3: Summary of key assumptions

Assumption	Approach	Possible implications
Bookings and flows	For all users other than gas distribution networks (GDNs), we set bookings 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 (in which case we would expect some 'over-booking'). This will increase capacity tariffs as they are distributed over a smaller set of users. This assumption applies equally to all options. As explained above, we note that this may particularly affect analysis of option UNC0728C in comparison to other options. We carry out a sensitivity to consider the impacts of relaxing this assumption for shorthaul users under UNC0728C in particular. This also has implications for the way in which Transmission Services Charge discounts and Non-Transmission Services Charge discounts are applied under the options. In reality, Transmission Services Charges are applied based on capacity bookings while Non-Transmission Services Charges are applied based on actual flows. Because we assume that capacity bookings are set to equal flows, there is no difference between the two applications in our modelling.
Existing contracts	Existing contracts are utilised first where these are cheaper than the respective entry capacity tariff. As these contracts are already in place, we assume that they will be netted off the FCC and revenue recovery requirements. We also assume that shorthaul users will optimise between the use of existing contracts and capacity bookings using the available shorthaul product, while also considering the impact of utilising an existing contract on the non-transmission entry tariff they will pay.	This assumption will effectively increase the revenue recovery requirements relative to reality. In reality, it is likely that utilisation of existing contracts will be higher as contract holders may choose to utilise these anyway or sell them at a price lower than their cost. This may have an upwards impact on tariffs in practice as lower new capacity bookings may be made. As the number of existing contracts reduce over time, the impact is likely to be greater in 2022/23 in comparison to 2030/31.
Booking allocations	Where shippers do not book capacity using the shorthaul product, we assume that the proportions of different capacity products that are booked by users are equal to that observed in the latest available gas year (2017-18). This assumption allows us to reflect the proportion of	Under both the counterfactual and the modelled option, we consider that proportions of capacity bookings of different products would be relatively consistent.

Assumption	Approach	Possible implications
	different types of bookings which are currently observed at different entry and exit points.	Given multipliers of 1 across products other than the interruptible product (which has a multiplier of 0.9), the impacts of this assumption are small.
Revenue recovery requirements	We set revenue recovery requirements based on estimates set out in RIIO-1 and RIIO-2 until 2024/25, from which point we hold revenue recovery requirements constant in real terms.	Depending on revenue recovery requirements under future price controls, our assumption may represent an under- or over-estimate in different years. This will have a similar impact across UNC0728 and the status quo, 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 several 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 price. We provide further detail on the structure of the electricity market model in Appendix B.

Assumptions used in the gas market model

To make modelling of the modification option feasible, we incorporated several necessary 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.

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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, as well as all power station nodes than NGGT identified as possible bypass routes for UNC0728 analysis.[13] We consolidate the remaining NTS-connected power stations into grouped nodes in the market model, depending on the generation technology and relevant efficiency.[14] We do the same for LDZ-connected power stations, (whose flows are part of the DNO exit points).[15]	This allows us to model gas flows and revenues for all large power stations that may make use of the shorthaul product in addition to those made use of the OCC in 2017-18. We can only consider the residual power stations in the aggregate, as differentiated by technology and efficiency (as well as grid connection).
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 OCC tariff.	Our analysis does not fully reflect the potentially complex commercial arrangements which may be involved in contractual arrangements relating to shorthaul.
Shorthaul routes	We only consider routes in the list compiled by NGGT for UNC0728.[16]	Our analysis does not incorporate these potential future users of the shorthaul product where these potential routes have not been indicated to us by Ofgem or NGGT.

[13] These power stations represent approximately 86-88% of the NTS-connected gas-fired generation capacity over our modelling horizon, depending on the scenario (as per the FES) and spot year.

[14] We include four gas-fired generation technologies at the NTS level, as per the FES – CCGT, OCGT, CHP, and reciprocating engines. We split the CCGT group into two nodes – one for high-efficiency CCGTs, and one for lower-efficiency plants. The efficiency level used to determine the high and low efficiency categories is the average of the current GB CCGT fleet of 'major power producers'(as published by BEIS in the DUKES database), which stands at 48.8%.

[15] We include four gas-fired generation technologies at the LDZ level, as per the FES – CCGT, OCGT, CHP, and reciprocating engines. We do not split any of these nodes by efficiency

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

Assumption	Approach	Possible implications
Existing contracts	Existing contracts are not included in the gas market model. Inclusion of existing contract pricing at each node would require developing a new GB market model which was not feasible within the scope 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.[17] 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.[18] 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.
Power station closures	We take assumptions on closure of individual NTS-connected power stations directly from the FES for each scenario and spot year (based on confidential data provided to use by National Grid as part of this contract). Depending on the scenario and year, this also includes some power stations that would be eligible to use the shorthaul product and which would have been considered in our analysis otherwise.	This assumption allows us to align more closely with our chosen FES scenarios. However, inevitably, actual closure programmes may be somewhat different in practice.

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

[18] Ibid.

The electricity market model

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.

Where UNC0728 effects on the electricity wholesale price, this may impact on 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 a scenario 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 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. While the precise impacts may be dependent on the supply and demand dynamics under UNC0728, we do not identify any reason to believe that this would result in a greater impact under UNC0728 as opposed to the status quo.

2.1.3. Impact Assessment modelling

Our impact assessment (IA) model[19] 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; and
- impacts on carbon emissions.

As all entry points are included within the tariff and market models, we can 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, 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 (other than power stations).

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.

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

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

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[19] 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) published in June 2020.	Vulnerable: 11.4 MWh/year
	Based on consumption levels defined in Ofgem's Typical Domestic Consumption Values which took effect on 1 April 2020.	Medium: 12 MWh/year
Industrial and commercial consumer	Based on BEIS gas consumption statistics published in December 2019, we estimate impacts for LDZ-connected I&C consumers by taking the median consumption of small non-domestic consumers in GB.	LDZ-connected: 149.3 MWh/year
	We used confidential National Grid data to develop approximate median consumption for NTS-connected consumers in 2017/18.	NTS-connected: 400,000 MWh/year

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 based on the BEIS National Energy Efficiency Data-Framework (NEED) published in June 2020.	Vulnerable: 2.8 MWh/year
	Based on consumption levels defined in Ofgem's Typical Domestic Consumption Values which took effect on 1 April 2020.	Medium (PC1): 2.9 MWh/year
Industrial and commercial consumer	Based on BEIS electricity consumption statistics (published in December 2019), we estimate impacts on LDZ-connected I&C consumers by taking the median consumption of small non-domestic consumers in GB.	LDZ-connected: 7.0 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

2.1.4. Bypass analysis

The shorthaul product was originally 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 shorthaul product is an optional tariff, which is intended to reflect the fact that 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 a shorthaul product.

Eligibility limits and the relationship between distance and the shorthaul discount are intended to reflect this. The shorthaul discount results in a cross-subsidy with more revenue needing to be recovered from those who do not use the product. Therefore, an effective shorthaul product should aim to reduce the risk of bypass while balancing the bypass deterrent against the size of the discount.

We have performed analysis of potential bypass incentives to provide an indication of the likelihood that bypass pipelines may be built under each option. This analysis relies on several important 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 than can be captured in our model.[20]

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.[21] This allows us to assess whether the investment in a bypass pipeline would be commercially attractive within a five-year time horizon under each option.

We estimated bypass pipeline costs by adapting a cost function developed by NGGT. 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).

We deviate from NGGT's cost function in two key areas:

- The NGGT cost function assumes that the pipeline size will be in line with the Maximum NTS Exit Point Offtake Rate (MNEPOR). Instead, we assume that the pipeline will be sized to our modelled maximum flow rate (over the whole of our modelling horizon, and over both scenarios). This allows us to model all routes consistently, including those for which the MNEPOR calculation was not available.[22]
- The cost function also assumed 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 and relative to our assumed pipeline size.[23]

Assumptions in the bypass model

To make the modelling of modification option feasible, we incorporated several necessary assumptions and abstractions. We summarise the key assumptions in Table 2.7.

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

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

[22] This was the case for offtakers that did not utilise the OCC product historically.

[23] This is based on modelled flows 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.

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 is likely to overestimate the percentage of routes that may present a significant risk of bypass from 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. For power stations, we took their maximum modelled flows across options for each scenario and year.	Following investment in a bypass pipeline, the marginal costs of an additional unit of flow may be close to zero (especially where compressors are not needed over short distances). Therefore, those who do build a bypass pipeline may increase their flows, allowing for payback on investment in a shorter period of time. This may particularly be the case for power stations, as their demand is more elastic. We take the maximum flows across options, to mitigate against the risk of underestimating 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%.	Relative to 100% load factors, our use of actual flows means that network users are less likely to invest in bypass pipelines than would otherwise be the case. We consider that it is 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 their bypass pipeline.
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. that the shorthaul product would have been used where eligible.	In practice, there may be potential constraints on the capacity available under the shorthaul product. This assumption in isolation may imply that our modelling may underestimate the risk of bypass. This also impacts our estimates of lost revenue recovery 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 but not exceed their modelled maximum flows to cover capacity requirements.	In practice, users may make a commercial decision to build a larger pipeline than their modelled capacity requirement at peak, to allow for some forecasting error. In the case that users did choose to build a larger pipeline, payback time may increase, resulting in a lower risk of bypass than our modelling suggests.

Assumption	Approach	Possible implications
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.
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 that only direct capital and operational costs are included is likely to have the most significant impact on the modelled risk of bypass. 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 overall our analysis represents an over-estimate of bypass risk.

3. FIRST ORDER TARIFF AND WELFARE EFFECTS

In this section, we present findings from our quantitative tariff, market and impact assessment modelling. We focus on the first order effects of the options, most notably, the extent of the tariff discounts, impacts on the tariffs of non-eligible users and the consequential changes in the modelled gas and electricity prices. This provides an indication of the first order impacts on consumer welfare.

However, the analysis in this section assumes that all existing users of the gas network remain on the system. Ofgem has previously set out that any shorthaul product should be focused on deterring the potential for bypass of the NTS by users of the gas network. In the case that users choose to bypass, they would no longer contribute towards revenue recovery. This revenue would need to be re-allocated to remaining users of the system and the tariffs for all users would increase.

It is therefore important to also consider the second order effects of the options – i.e. the extent to which they can discourage system bypass and prevent an increase in tariffs and reduction in consumer welfare. As discussed in Section 4, this analysis is subject to a greater degree of uncertainty than the first order effects. We present our bypass analysis and potential second order effects in Section 4.

3.1. CHOICE OF SCENARIOS AND GAS YEARS

Gas transmission tariffs are designed to recover NGGT's allowed revenue from gas entry and exit points. In our analysis, we assumed that capacity is booked to meet 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 CT scenario in gas year 2030/31, tariffs are projected to be the highest in this gas year. Therefore, the relative impacts of the modification option in comparison to the status quo are likely to be the largest in this case.

In the remainder of this section, we present the results from our modelling of UNC0728. To demonstrate the most significant potential impacts, we present the results of the CT scenario in gas year 2030-31, unless otherwise stated. We provide additional results for tariffs and prices from other gas years in Appendix A.

3.2. IMPACTS ON TARIFFS AT ENTRY AND EXIT POINTS

In this section, we summarise the impact of UNC0728 and alternatives on the tariffs at entry points, exit points and combined entry and exit points (storage facilities and interconnectors[24]). We present the 'commoditised' standard firm Transmission Services Charge[25] (in p/kWh/day) and the additional Non-Transmission Services Charge (also in p/kWh/day) throughout.

The shorthaul product allows a proportion of shippers to benefit from a discount on their entry/exit tariff. This results in an additional amount of revenue that needs to be recovered from non-shorthaul capacity bookings and leads to a rise in the non-shorthaul tariff.

[24] 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.

[25] Given multipliers of 1 for all standard firm capacity products and the postage stamp nature of the RPM, all entry points and all exit points would face an equivalent firm tariff for an equivalent level of capacity. We 'commoditise' the tariff to demonstrate the price of capacity that is needed for a single unit of flow. This is relevant for GDNs. As GDNs are the only user for whom we assume a level of overbooking, we observe a higher 'commoditised' tariff for these exit points.

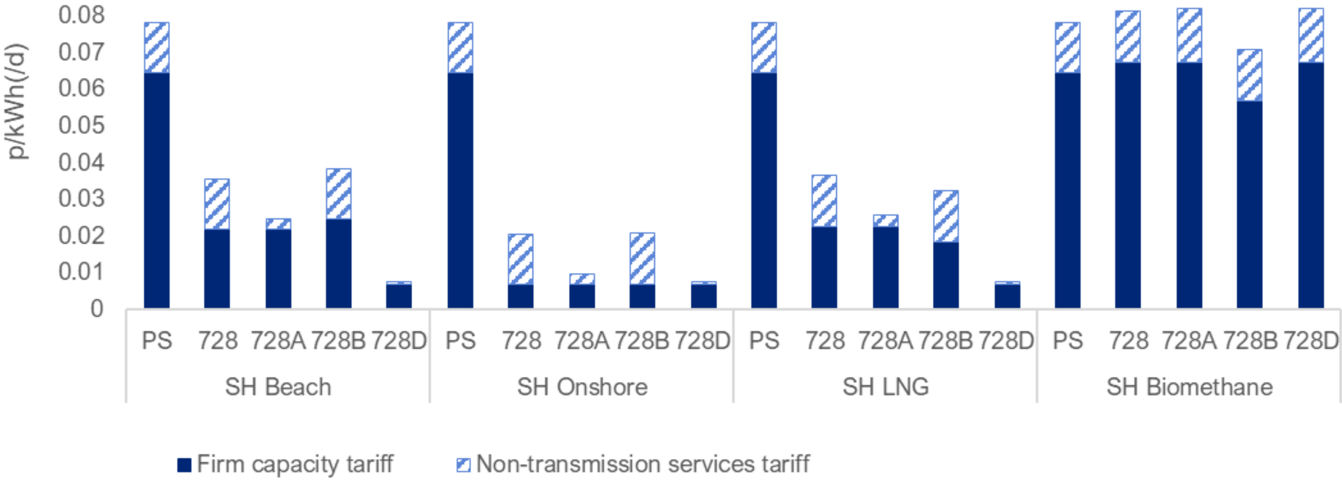
3.2.1. Impacts of options on tariffs at entry points

In this section, we consider the impacts of the modification options on the applicable tariffs at entry points. We consider the magnitude of the tariff discount under each option relative to the status quo[26]. We then consider the impact this has on tariffs for non-shorthaul users, given the resulting increase in the revenues that must be recovered from capacity booked on non-eligible routes.

Impacts on entry tariffs for eligible shorthaul routes

Figure 3.1 sets out the impacts of the options on the tariffs for those entry points that are eligible for the shorthaul product under each option, relative to the status quo non-discounted tariffs. We present the average tariff-weighted by applicable capacity bookings for eligible shorthaul beach terminals, onshore fields, LNG terminals and a single eligible biomethane facility.

Figure 3.1: Entry tariffs for eligible shorthaul users by entry point type (CT, 2030-31, £18/19)[27]



Focussing on the discounted tariffs at beach, onshore field and LNG entry points, we can observe consistent trends between the options. All options lead to significant weighted average discounts relative to the postage stamp status quo tariff.

We can observe the 90% discount for Option D with eligible routes including some shorthaul beach terminals, onshore fields and LNG terminals.

UNC0728 and UNC0728A have identical eligibility criteria and the same applied discount for the Transmission Services Charge proportion of the shorthaul tariff. More routes are eligible under these options than under UNC0728D but with a lower average tariff discount.

Eligibility is widest under UNC0728B. The discount under UNC0728B is more generous than under UNC0728 for an equivalent route distance. Whether the weighted average discount is higher or lower than under UNC0728 and UNC0728A depends on which entry points of a certain type are eligible under each option and on the effective distances for the eligible routes. The weighted average discounts are of a similar magnitude for UNC0728B as for UNC0728 and UNC0728A but can be slightly higher or lower depending on these factors.

[26] The status quo tariff is a postage stamp reference price mechanism with no shorthaul product. It is labelled as PS ('Postage Stamp') in the charts in this report.

[27] Note that for the status quo we have used the FES to developed scenarios for future peak demand and supply. We have then applied NGGT's tariff model to calculate the tariff under the status quo based on the relevant scenario.

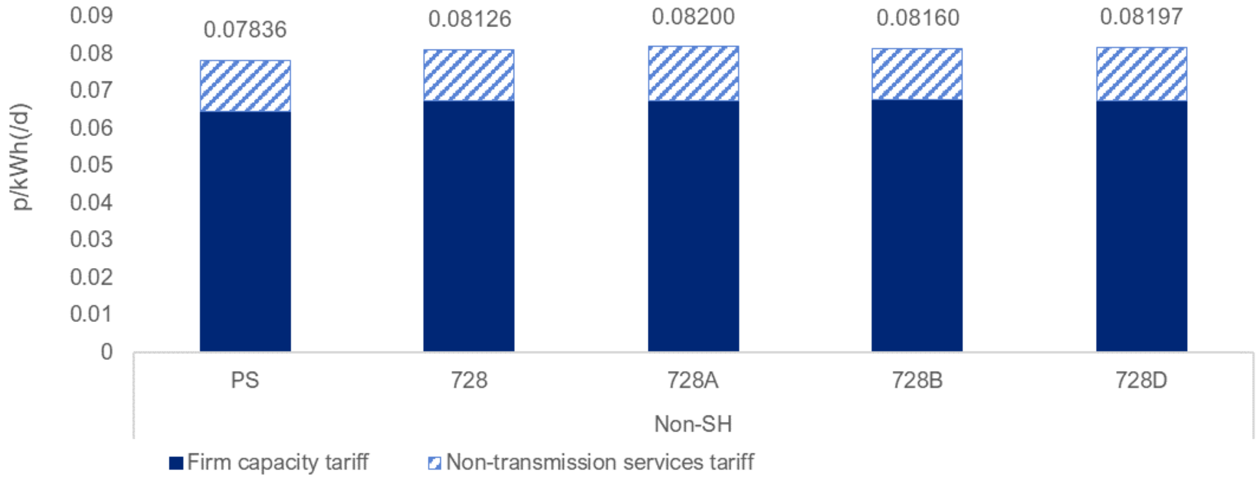
The chart also shows the impact of the Non-Transmission Services Charge discount for eligible routes at entry. The 80% and 94% discounts applied under UNC0728A and UNC0728D provide a potentially important additional benefit to eligible shorthaul shippers.

We only include one biomethane entry point within our analysis, and this has a route distance of greater than 18 km. We therefore only observe a discount relative to the postage stamp status quo under UNC0728B, and given that this distance is towards the upper end of the range, the discount is relatively small.

Impacts on entry tariffs for non-shorthaul users

Assuming no change in the volume of capacity bookings, discounts on eligible shorthaul capacity result in lower revenue contributions from these users. This additional revenue must be recovered from non-shorthaul capacity bookings. In Figure 3.2 we show the impact of shorthaul discounts on non-shorthaul capacity tariffs at entry.

Figure 3.2: Entry tariffs for non-shorthaul users (CT, 2030-31, £18/19)



Under all of the options, the total volume of non-shorthaul capacity would be significantly larger than shorthaul capacity. Therefore, the additional revenue requirements which is recovered from non-shorthaul capacity bookings is spread over a greater volume of capacity. Hence, the increase in the tariff per unit of capacity for non-shorthaul users is smaller than the equivalent discounts observed for eligible shorthaul users.

The size of the increase in the non-shorthaul tariff is driven by three features of the design of the shorthaul product:

1. the magnitude of the Transmission Services Charge discount,
2. the inclusion and magnitude of the Non-Transmission Services Charge discount, and
3. the breadth of eligibility for the discount.

The inclusion of the Non-Transmission Services Charge discount under UNC0728A and UNC0728D result in the most significant increases in the non-shorthaul tariff. Under UNC0728A, the discount for routes with a route distance less than 5 km is lower than under UNC0728D. However the additional revenue recovery requirements are balanced against the availability of a discount for additional shorthaul capacity with route distances up to 18 km. These routes are not eligible under UNC0728D.

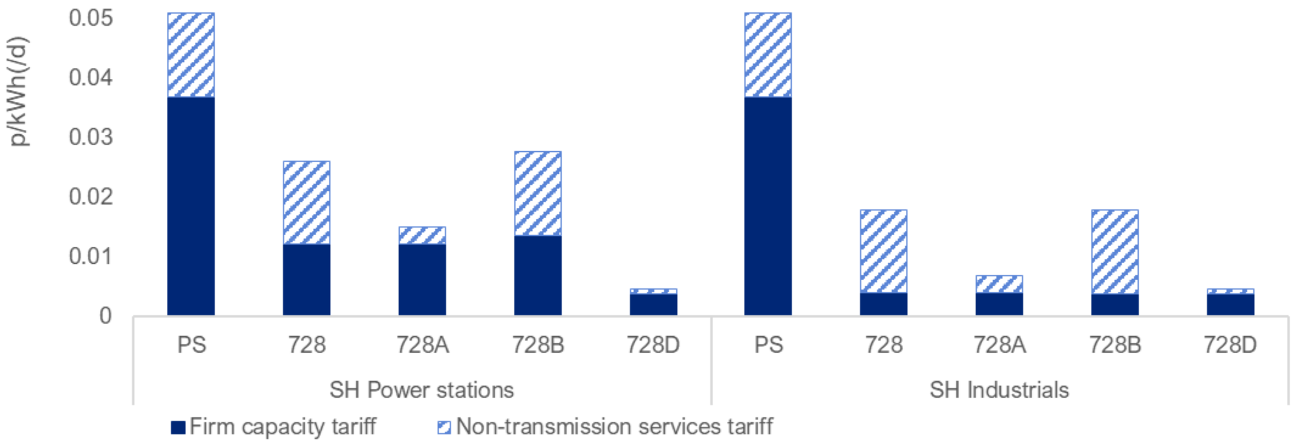
UNC0728 and UNC0728B result in smaller increases in the non-shorthaul tariff. The breadth of eligibility under UNC0728B results in a larger increase in the non-shorthaul tariff than under UNC0728.

3.2.2. Impacts on annual tariffs at exit points

Impacts on exit tariffs for eligible shorthaul routes

We consider the impact of the options on the exit tariff for eligible shorthaul routes in Figure 3.3. As we cover interconnector exit points separately[28], we only consider industrial and power station exit points in this chart.

Figure 3.3: Exit tariffs for eligible shorthaul users by exit point type (CT, 2030-31, £18/19)



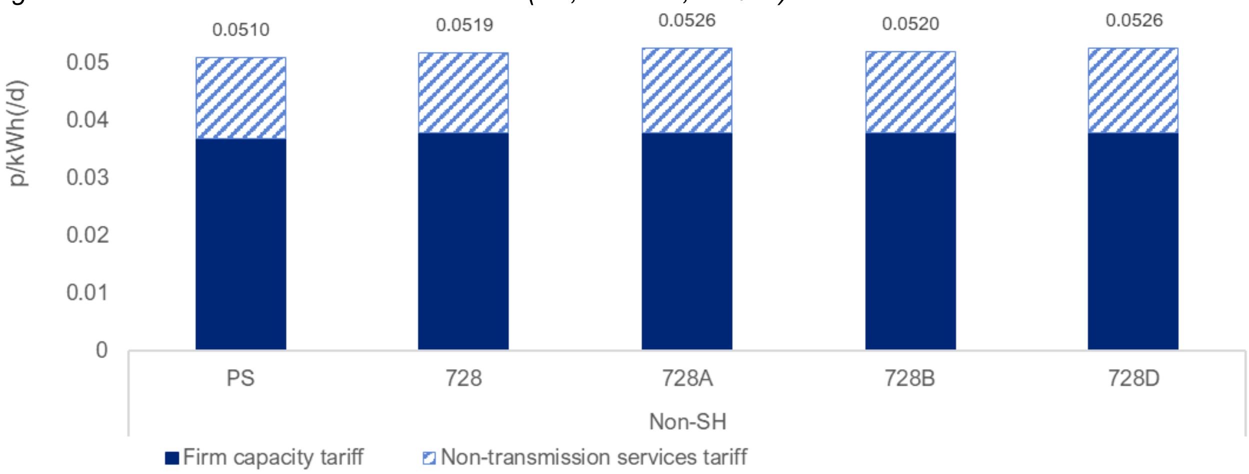
The relationship between options is similar to that observed at entry. UNC0728D results in the greatest discount for eligible routes, followed by UNC0728A. In both cases, the Non-Transmission Services Charge discount contributes to the benefits associated with the discount.

The majority of eligible shorthaul industrial capacity is located a relatively short distance from nominated entry points. This helps to explain the more significant discounts observed under all options for these exit point types.

Impacts on exit tariffs for non-shorthaul users

The discount on the exit tariff for eligible shorthaul routes results in an increase in revenue recovery requirement for non-shorthaul users. As before, the magnitude of impact is smaller than the discount for shorthaul exit points given the greater volume of capacity of non-shorthaul users. At exit, the 'over-booking' assumption applied to GDNs results in a greater volume of capacity bookings from non-shorthaul users than at entry.

Figure 3.4: Exit tariffs for non-shorthaul users (CT, 2030-31, £18/19)



For reasons discussed previously, we observe a similar trend to that seen at entry. UNC0728A and UNC0728D result in the biggest increase in the non-shorthaul exit tariff, followed by UNC0728B and UNC0728.

[28] And as GDNs and storage exit points are not eligible for the shorthaul product.

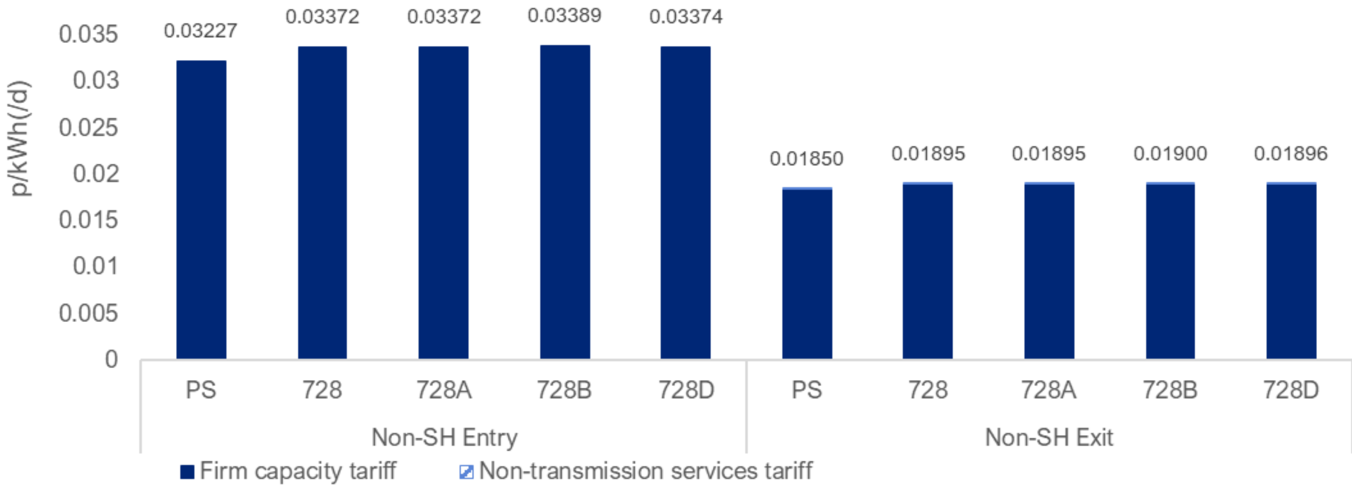
3.2.3. Impacts on tariffs at entry/exit points

We now consider the impacts of the modification option at combined entry and exit points – gas storage and gas interconnectors.

Impacts on tariffs at storage points

Storage entry and exit points are not eligible for the shorthaul discount and are therefore only impacted by the increase in the non-shorthaul tariff. Shorthaul entry and exit points benefit from a 50% discount on the Transmission Services Charge, they do not pay the Non-Transmission Services Charge at entry, and only pay the Non-Transmission Services Charge for 'own use gas' (a very small percentage of flows) at exit.

Figure 3.5: Entry and exit tariffs at storage points (CT, 2030-31, £18/19)

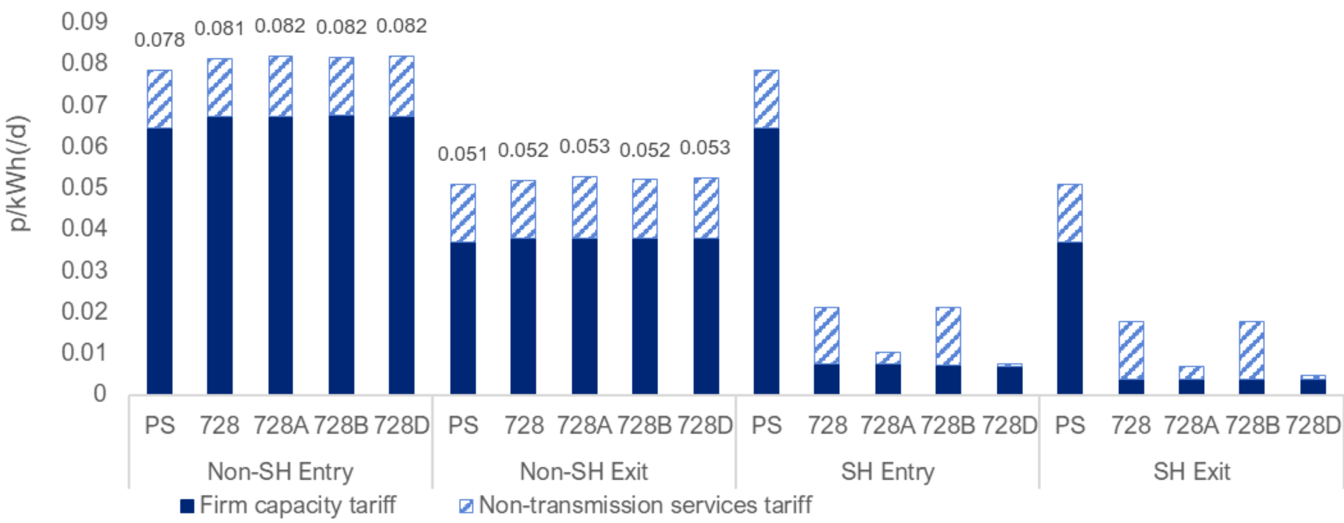


Storage points are therefore only impacted by the change in the Transmission Services Charge element of the tariff. Considering only the Transmission Services Charge element, there is a broadly equivalent increase in the entry and exit tariff under options UNC0728, UNC0728A and UNC0728D. The increase is more pronounced under UNC0728B.

Impacts on tariffs at interconnection points

We include two interconnector entry and exit points in our modelling. We combine IUK and BBL into a single entry/exit point at Bacton, and include Moffat as an exit point. We assume bidirectional capabilities at IUK and BBL. There are eligible shorthaul routes at the Bacton entry and exit point under all modification options. However, there are no routes to Moffat with a straight line distance within the eligibility criteria under any option.

Figure 3.6: Entry and exit tariffs at interconnector points (CT, 2030-31, £18/19)



The chart shows the potential discount available to shippers on eligible routes at Bacton entry and exit. The trends are consistent with those previously observed for eligible shorthaul routes at entry and exit. It also shows the impact on capacity bookings at Moffat and at Bacton that are not eligible, again in line with previous trends observed for non-shorthaul entry and exit points.

3.3. Wider systems analysis

In this section, we present our analysis of the wider system impacts, including the gas and electricity price. We focus our analysis on the effects of the options on consumer welfare. We provide tables setting out the potential impacts on producers in Appendix A A.

3.3.1. Impacts on consumers

In this section, we explore the impact of the options on consumers, relative to the status quo. .

Consumer welfare impacts arise from three 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 onto those consumers connected at GDNs in full.
2. The **wholesale gas price**: The change to tariffs may impact on the marginal unit of gas supply which may in turn affect the wholesale gas price. We assume that any changes to the wholesale gas price will be passed onto consumers.
3. The **wholesale electricity price**: Changes to the gas price and the exit tariff will affect the cost of gas consumed by gas-fired power stations. This will in turn affect the wholesale electricity price which will then be passed onto electricity consumers. We present impacts on electricity consumers in Section 3.4.43.4.4.

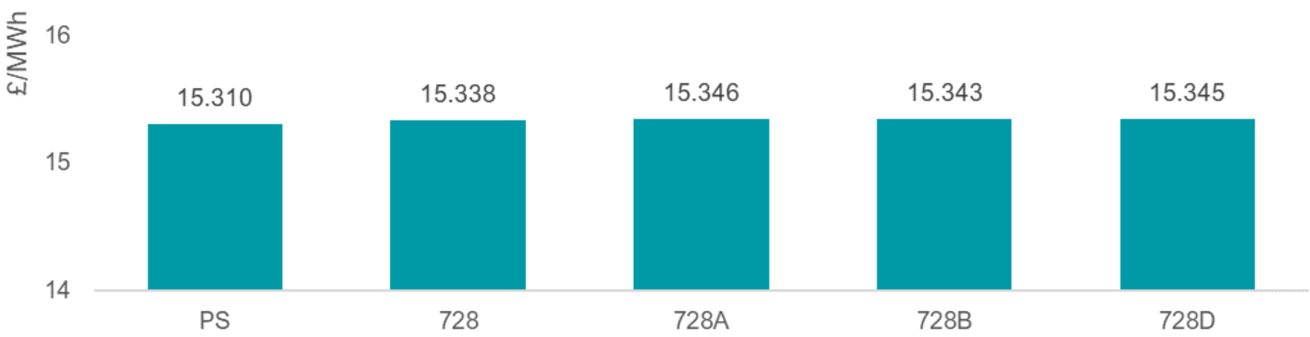
Even a small change in the wholesale gas price would impact on a large volume of gas consumption and can therefore result in large impacts on consumer welfare in the aggregate. For example, under the CT scenario in 2030-31, annual gas consumption is approximately 759 TWh per year.[29] Therefore, even a small change in the gas market price of £0.1/MWh would result in a total annual benefit to gas consumers of £76 million.

Consumer welfare impacts are sensitive to the marginal unit of gas supply. 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.

3.3.2. Impacts on the wholesale gas price

We show the estimated impacts of the UNC0728 option on the gas wholesale market price in Figure 3.7 below.

Figure 3.7: Simulated wholesale gas market prices (£/MWh, CT, 2030-31, £18/19)



[29] 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.

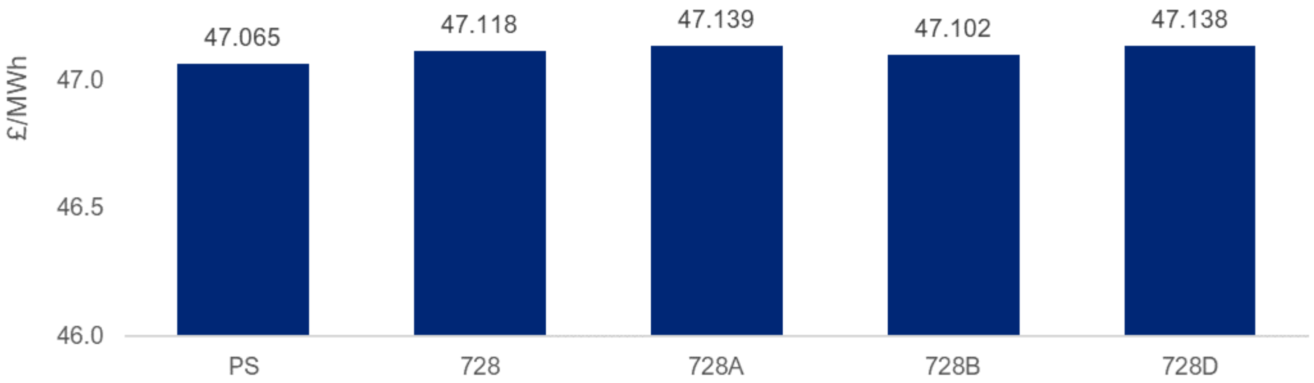
Figure 3.7 shows that the tariff methodology only has a small impact on the wholesale gas price, as would be expected. The maximum change in the gas price in 2030/31 is approximately 0.2% of the wholesale gas price observed in the counterfactual. The change in the gas price across the options is broadly proportionate to the increase in the non-shorthaul entry tariff shown in Figure 3.6. The exact impact depends on the change in the tariff at the marginal source of entry across the modelled spot year.

3.3.3. Impacts on the wholesale electricity price

Gas-fired power stations represent an important part of the electricity mix. From Q2 2019 to Q2 2020, between 23% and 33% of electricity in Great Britain was generated each quarter by gas-fired power stations.[30] The flexibility provided by gas-fired power stations means they often represent the marginal units of electricity and set the wholesale electricity price.

By combining the gas and electricity market models, we have performed analysis of the potential impacts on the electricity market resulting from UNC0728. Figure 3.8 shows the estimated impact of UNC0728 on the electricity market price under the CT scenario in gas year 2030/31:

Figure 3.8: Simulated wholesale electricity market price impacts (£/MWh, CT, 2030-31, £18/19)



We find that the change to the gas market price has a corresponding impact on the electricity price. The change in the electricity price is roughly twice the magnitude of the impact on the gas price. This reflects the efficiency of gas fired power stations of roughly 50% and the fact that these units remain marginal for the majority of periods within the year.

Comparing options, the electricity price trends generally follow the gas price trends. The only exception is the electricity price impact under UNC0728B. For this option, we observe a lower electricity price than for UNC0728 even though the gas price is higher (see Figure 3.8).

This is a result of the eligibility criteria and percentage discount available to power stations under UNC0728B. UNC0728B combines broader eligibility with a more generous shorthaul discount for the eligible points. Several power station exit points are eligible for the shorthaul product under this variant, in contrast to other variants. It also provides a higher discount for eligible power stations relative to UNC0728. Eligible shorthaul power stations represent a proportion of the electricity generation which sets the electricity price throughout the year. Hence, the larger and more widely applied shorthaul discount present within UNC0728B is passed through to the electricity market.

[30] See: Ofgem, October 2020, Electricity generation mix by quarter and fuel source (GB).

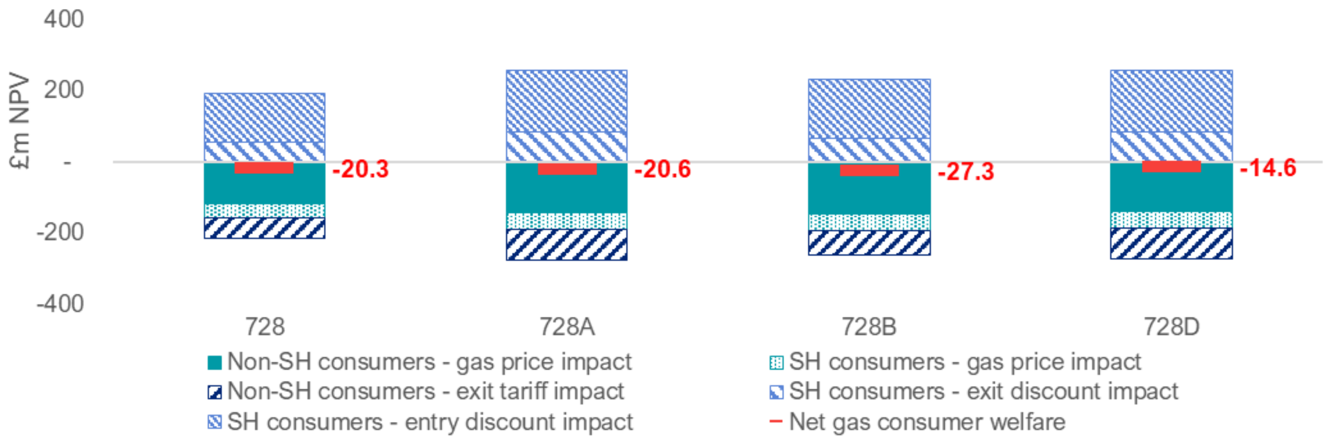
3.3.4. Consumer welfare

Relative to the status quo, gas consumer welfare impacts are driven by a combination of changes in the gas market price, the applicable tariff (discussed in Section 3.2) which is passed onto each type of consumer. Electricity consumers also experience welfare impacts as a result of the change in the electricity price.

Gas market consumer welfare impacts

In Figure 3.9, we present the NPV of the gas market consumer welfare impact between the years 2022 and 2031 under UNC0728. The consumer welfare impacts are presented relative to the status quo and includes the impact on all consumers of gas including residential, I&C customers and gas-fired power generators.

Figure 3.9: Gas consumer welfare (CT, 2022-2031, NPV, discounted to £18/19)[31]



Our consumer welfare results reflect the combination of impacts discussed previously. While the effects of the tariff reform and the impacts on gas prices are small, given that they impact on a large number of consumers, the consumer welfare impacts are more substantial.

Non-shorthaul consumers face a direct reduction in welfare from the increase in the exit tariff that was discussed in Section 3.2.2. They also face higher wholesale gas prices as shown in Section 3.3.2.

The shorthaul products provide a discount to the entry-exit point route which results in a discount in the tariff at entry and exit. We assume that the discounts at both entry and exit are passed through to the eligible offtaker such that the offtaker benefits from a discount at both exit and at entry. However, like non-shorthaul consumers, they also face an increase in the wholesale gas price. Note that the entry tariff discount effect outweighs the exit tariff discount effect because of the higher tariffs at entry than at exit (as a result of our overbooking assumptions for GDNs).

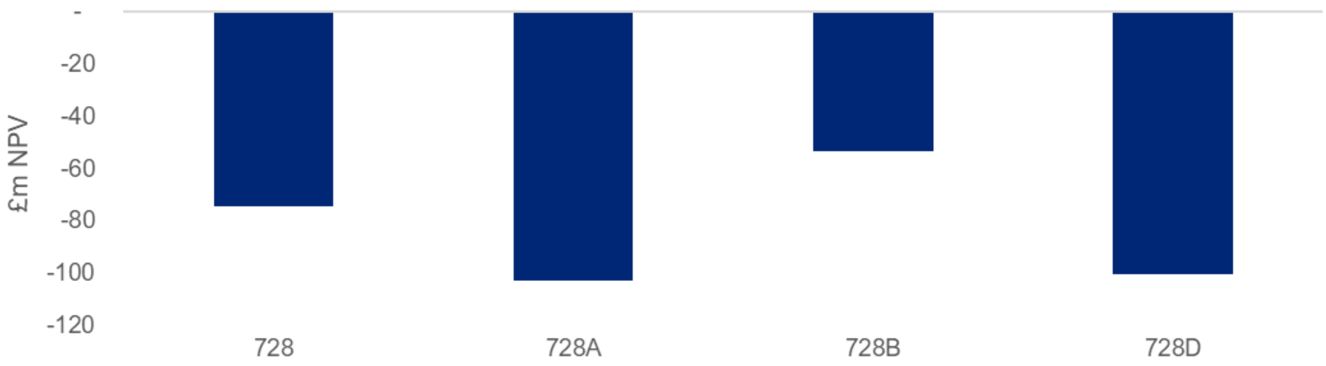
Shorthaul consumers face a net increase in welfare under all of the options, broadly in proportion to the level of discount observed. However, the loss of welfare faced by non-shorthaul consumers outweighs this. The balance of these distributional effects results in a small net welfare loss under all of the options.

Electricity market consumer impacts

In Figure 3.10, 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 including domestic and I&C customers.

[31] For ease of reference, we include the exit tariff impacts on storage and interconnector exit points in this chart. However, these are not considered to be 'end consumers' for the sake of the NPV benefits calculation.

Figure 3.10: Electricity market welfare impacts (CT, 2022-2031, NPV, discounted to £18/19)



Electricity consumer welfare impacts are a direct consequence of the change to the electricity price observed in Figure 3.8 multiplied by the total amount of electricity demand on the system. The reduction in electricity consumer welfare is therefore inversely proportion to the estimated increase in the electricity price.

The second order bypass effects (not included) are also relevant here. In the case that users chose to bypass the system, this could have knock on impacts on electricity consumer welfare. These impacts could result from an increase in the exit tariff and the wholesale gas price impacting on the wholesale electricity price.

3.4. BILL IMPACTS AND REVENUE IMPACTS FOR GAS-FIRED POWER STATIONS

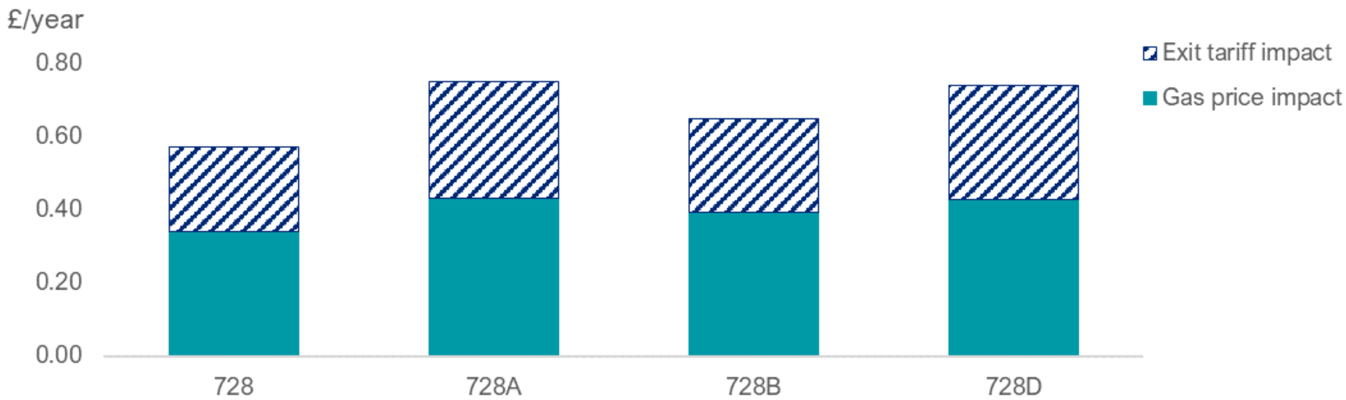
Next, we break down the total bill impact by consumer type, considering domestic and I&C consumers. We firstly consider the impacts on gas consumers, combining the impacts of the change in the gas market price and any change to the tariff at the relevant exit point. We then consider the impacts on electricity consumers as a knock-on effect from impacts on the gas market.

Finally, we consider the impacts on the revenues of gas-fired power stations in Section 3.4.5, taking into account the impacts in both the gas and electricity market.

3.4.1. Domestic gas consumer bill impacts

Bill impacts for the average domestic consumer are estimated according to household consumption levels, using the median gas consumption values from the BEIS NEED dataset as presented in Section 2.1.3.

Figure 3.11: Estimated gas bill impact for median consumption domestic gas consumers (CT, 2030-31, £18/19)

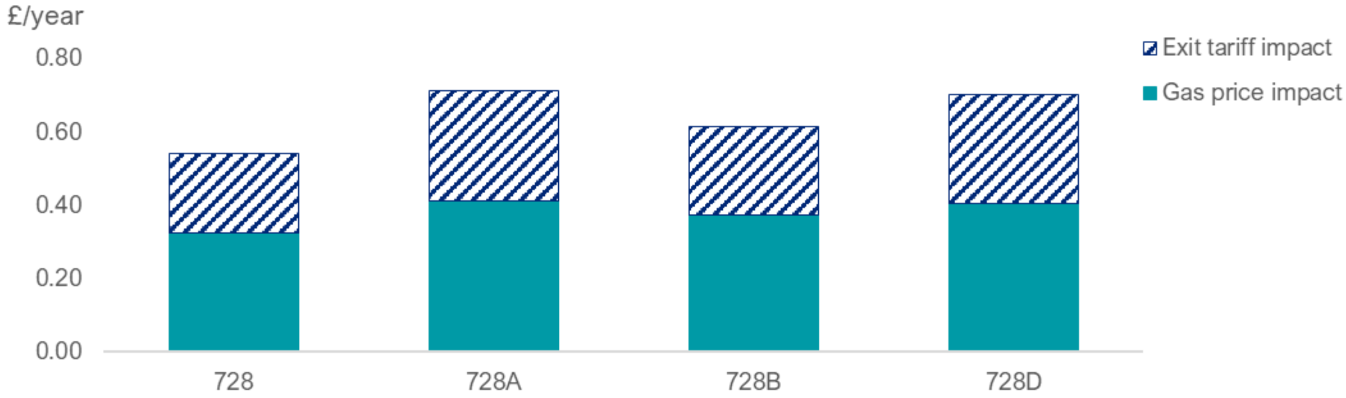


We see a small increase in annual bills across all options, driven by the increase in the wholesale gas market price and in the exit tariff for non-shorthaul consumers. The gas price impact on bills reflects the extent of the increase in the wholesale gas price and the exit tariff. The impact is largest under UNC0728A. The impact is limited to less than £0.80/year.

3.4.2. Impacts on vulnerable domestic consumers

We consider consumers who are financially vulnerable by taking an estimate of the median consumption for the most fuel poor quintile gas consumers from the BEIS NEED dataset.

Figure 3.12: Estimated gas bill impact for the most fuel poor quintile of domestic gas consumers (CT, 2030-31, £18/19)



The impacts on bills of consumers are proportional to the consumption levels of the most fuel poor quintile consumers. Consumption of the most fuel poor quintile median consumer is only slightly lower than that of the median consumer group. We therefore observe a similar increase in bills for this segment of consumers.

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 (all of which are non-shorthaul consumers) in Figure 3.13, and for NTS-connected non-shorthaul I&C consumers in Figure 3.14.

Figure 3.13: Estimated gas bill impact for the median non-domestic consumer connected to the LDZ gas network (CT, 2030-31, £18/19)

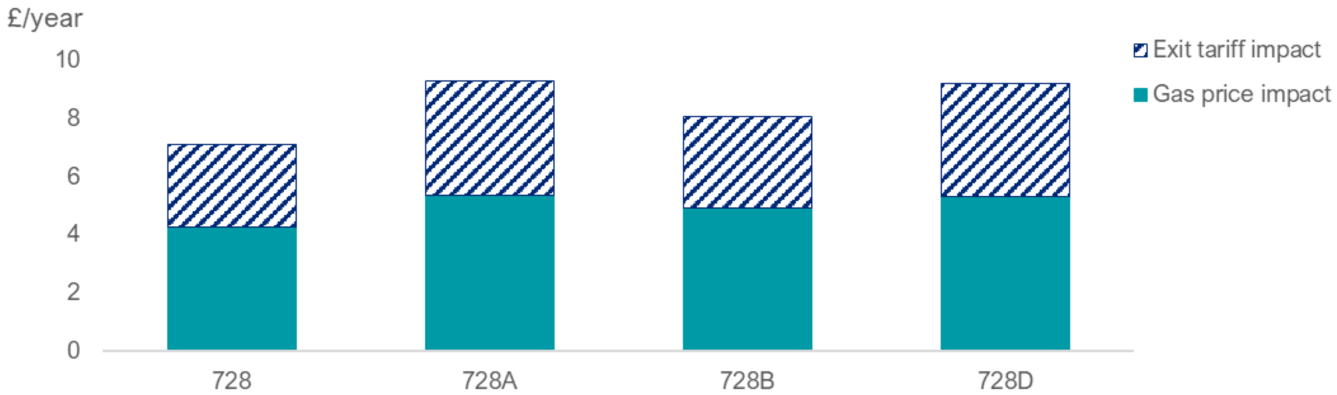
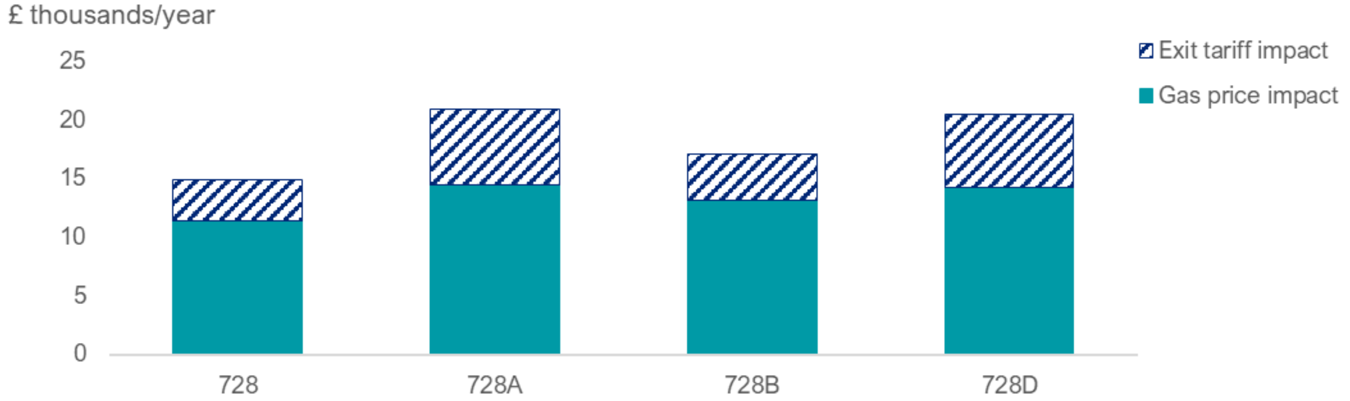


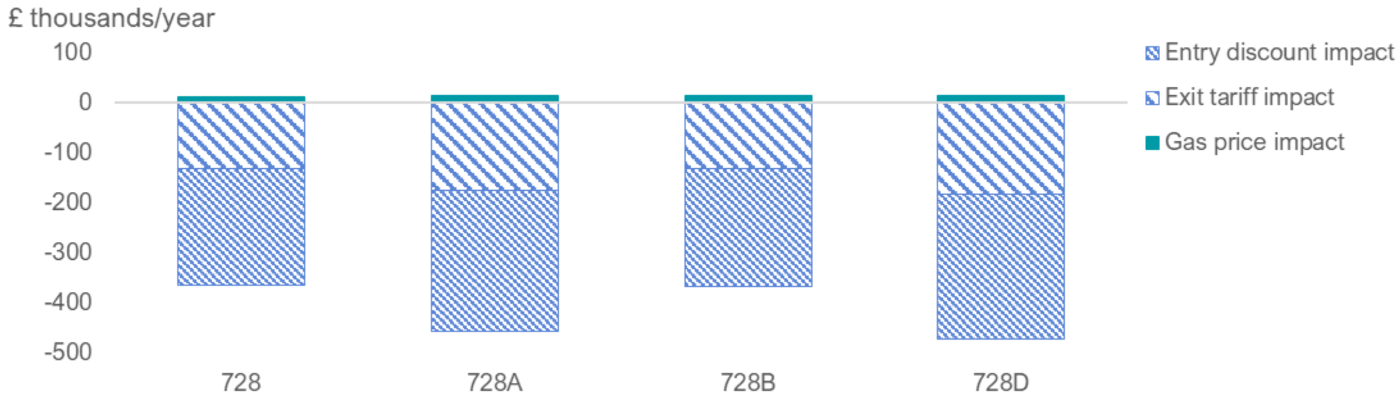
Figure 3.14: Estimated gas bill impact for the median non-domestic consumer connected to the NTS and either ineligible for or not utilising the shorthaul product (CT, 2030-31, £18/19)



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

We observe the same gas price effect for NTS-connected shorthaul I&C consumers, but the tariff impacts for these consumers differ. We present the combined gas price and tariff impacts for NTS-connected shorthaul I&C consumers in Figure 3.15. In practice, capacity constraints can limit the extent to which I&C offtakers are able to use the shorthaul capacity product to meet their full capacity needs. For comparability, we show the impact on the bill for a hypothetical I&C with median gas consumption that uses the shorthaul product for 100% of its capacity requirements.

Figure 3.15: Estimated gas bill impact for a hypothetical median NTS-connected non-domestic consumer that utilises the shorthaul product for 100% of gas capacity requirements[32] (CT, 2030-31, £18/19)



For NTS-connected shorthaul I&C consumers, we see the same gas price impact on bills as that for NTS-connected non-shorthaul I&C users as both the mechanisms (i.e. the change in the wholesale price) and the level of assumed consumption are the same. The tariff impacts on bills differ, reflecting the design of the options, which offer tariff discounts to shorthaul consumers.

For NTS-connected shorthaul consumers, we see large reductions in bills relative to the status quo as a result of reductions in the exit *and entry* tariffs. As discussed in Section 2.1, the shorthaul products relate to a given entry-

[32] Both historically and in our modelling, most shorthaul consumers utilise the shorthaul product for less than 100% of their flows, e.g. as a result of supply side constraints at their nominated entry point. In practice a given shorthaul user will see a smaller reduction in their bill than illustrated here, as any tariff discounts will only apply to the proportion of their bookings/flows that do utilise the shorthaul product.

exit route and provide a discount in the tariff at both entry and exit. We assume that the discounts at both entry and exit are passed through to the eligible offtaker.

We see the largest reduction in bills for NTS-connected shorthaul consumers under option 728D, closely followed by option 728A. Options 728 and 728B correspond to similar but slightly lower reductions on average. These reductions relative to the status quo are driven by the decrease in exit tariffs for I&C shorthaul consumers, as shown in Figure 3.3, and the corresponding level of discount available at those users' nominated entry points.

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 Section 3.3.3). This results from a combination of the change to the wholesale gas price and of the impact on the exit tariff for gas-fired power stations.

We estimate the impacts on the median bill of a domestic electricity consumer in Figure 3.16, and the impact on the median non-domestic distribution-connected electricity consumers in Figure 3.17. As a result of the impact on the electricity market prices observed previously, electricity bills increase slightly under all options.

Figure 3.16: Estimated electricity bill impact for the median domestic electricity consumer (CT, 2030-31, £18/19)

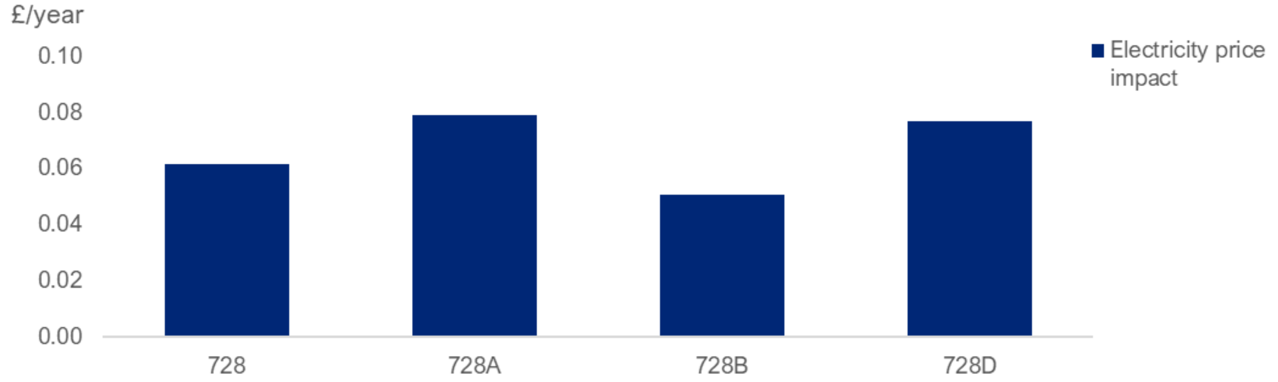
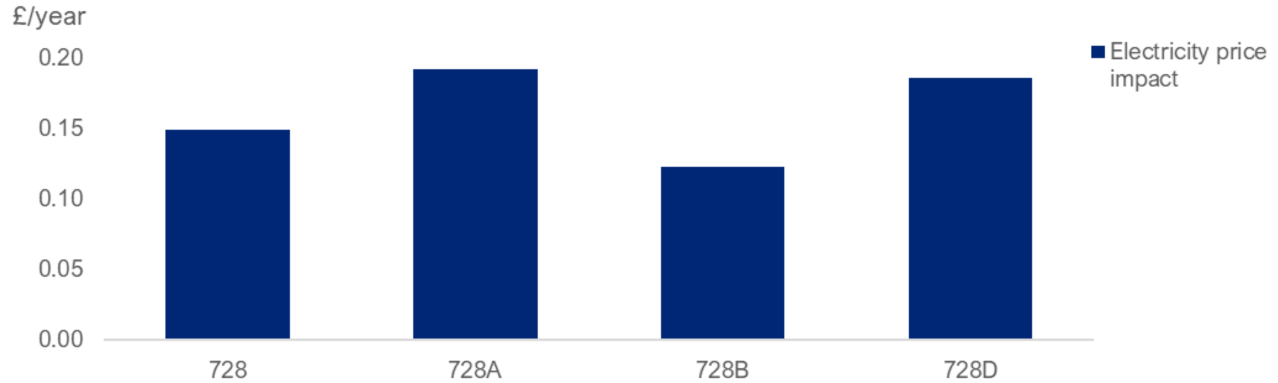


Figure 3.17: Estimated electricity bill impact for the median non-domestic electricity consumer (CT, 2030-31, £18/19)[33]



3.4.5. Impacts on gas-fired power stations

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

- generators connected to the LDZ,

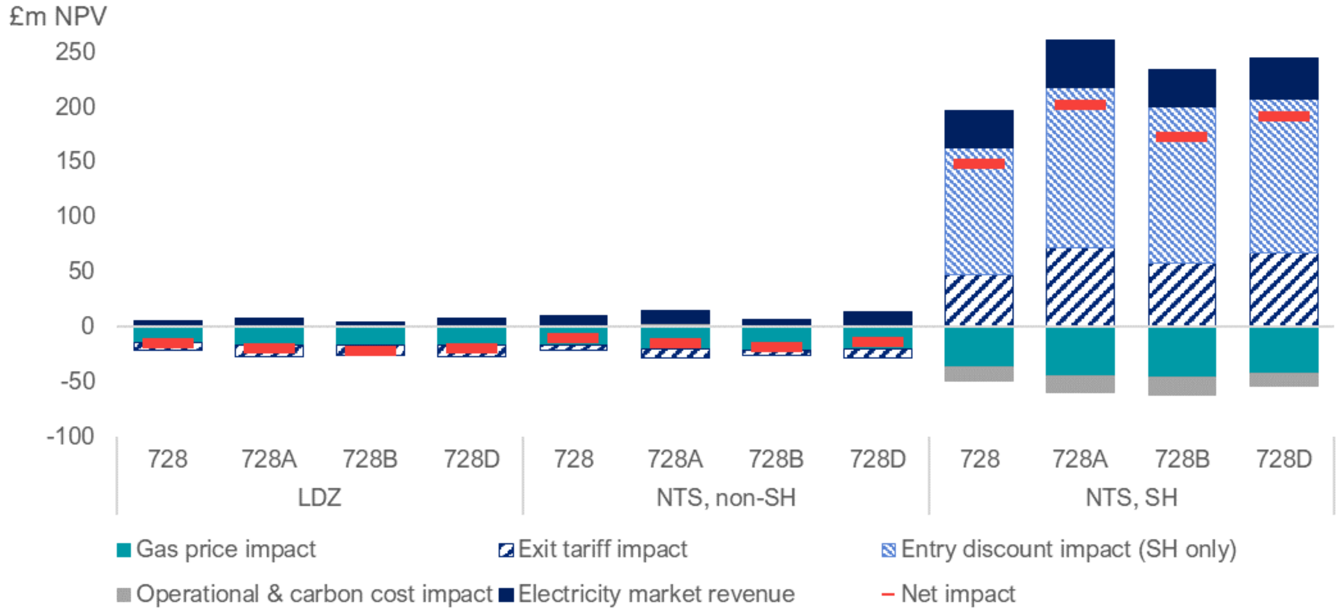
[33] Note that the electricity consumption of the median non-domestic electricity consumer is much closer to the median domestic electricity consumer than is observed for gas.

generators connected to the NTS, that are not eligible for shorthaul products (under any option) and
- generators connected to the NTS, that are eligible for shorthaul products (under any option).

The net revenue impact on gas-fired power stations is calculated based on revenues from electricity sold by generators at the wholesale electricity price. It also takes into account the cost of gas (including the wholesale gas price and transmission tariffs), operational and carbon costs.

We show the collective estimated impacts on each type of GB gas-fired power stations in Figure 3.18.

Figure 3.18: Impacts on revenues of GB gas-fired power stations (CT, 2022-2031, NPV, £18/19)



We find that net revenues for LDZ-connected and NTS-connected non-shorthaul power stations are lower under the options relative to the status quo, but higher for NTS-connected shorthaul power stations.

To explain this impact, we consider the drivers behind power station net revenues. As consumers of gas, all power stations face a negative impact from the increase in the wholesale price of gas. LDZ-connected and NTS-connected non-shorthaul power stations face the negative impact of an increase in exit tariffs, while NTS-connected shorthaul power stations benefit from tariff discounts, both at entry and exit.

This also affects the relative competitiveness of shorthaul power stations compared to non-shorthaul ones. We observe slightly higher electricity generation from shorthaul power stations and lower generation from non-shorthaul power stations relative to the status quo. The volumes of electricity generated by each in turn affect electricity market revenues.[34] Nevertheless, non-shorthaul power stations (with higher gas tariff costs) remain marginal for the majority of the period, pushing up the average wholesale electricity price.

While power stations collectively benefit from an increase in the wholesale electricity price, net electricity market revenues increase only for shorthaul power stations (decreasing for non-shorthaul stations) as a result of both the changes in generation and the ability of shorthaul power stations to benefit from additional inframarginal rents.

[34] Operational and carbon costs are constant per unit of generation for each individual power station in these groups. Hence these increase for shorthaul power stations relative to the status quo as a result of the increase in generation (having a negative impact on net revenues), and vice versa for non-shorthaul power stations.

3.5. Impacts on carbon emissions

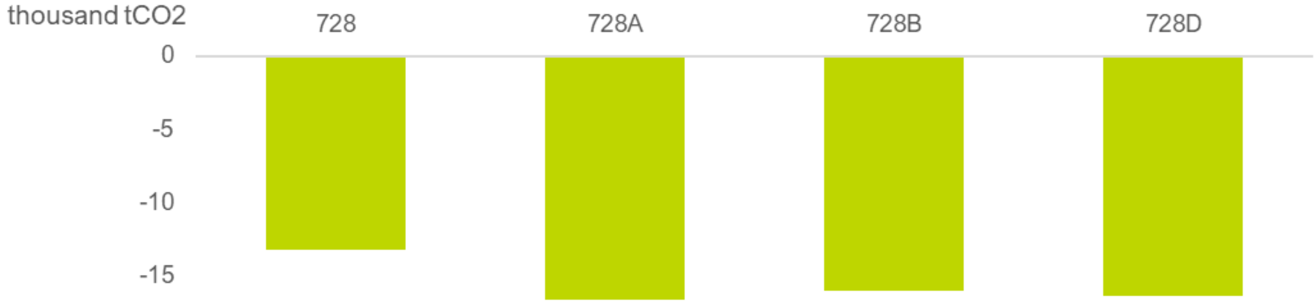
Gas tariffs may affect electricity generation from gas-fired power stations and electricity demand. Many of the beneficiaries of the shorthaul product under the options are gas-fired power generators. However, there are also many gas-fired power stations that do not fall within the eligibility criteria under any of the options. Through the changes in the electricity price, the options may also have a marginal impact on electricity demand.

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 an increase in gas-fired generation to increase carbon emissions following closure of coal plant in the spot years 2026/27 and 2030/31.

We set out the modelled impacts of the options on carbon emissions under the CT scenario in Figure 3.19. We observe slightly lower emissions under the options than under the status quo. This is a combination of two factors. Firstly, in gas year 22-23, some additional gas-fired power generation replaces dirtier fuels, particularly some remaining coal fired generation. Under our modelling, in 26-27 and 30-31, there is no coal fired generation remaining on the system. However, there is a small shift from non-shorthaul to shorthaul gas-fired power generation. In the aggregate, we find that shorthaul power stations tend to be larger, more efficient plant relative to non-shorthaul. Therefore, the displacement of non-shorthaul gas-fired power generation by shorthaul power plants tends to reduce carbon emissions.

In the context of the electricity system, we are talking about marginal changes to generator behaviour as a result of tariff and gas price changes. In comparison to the relative differences between carbon emissions observed in the CT and SP scenarios, it is not surprising that the incremental impact on emissions is very small (maximum reduction of around 15,000 tonnes (CO2)).

Figure 3.19: Changes in average annual carbon dioxide emissions under each option (CT, 2022-31)



3.6. UNC0728C tariff sensitivity

In Section 2.1 we discussed the fact that UNC0728C is identical to UNC0728 in all aspects other than the definition of the capacity on which the shorthaul discount is based. Under UNC0728, shorthaul capacity bookings that are not used for actual flows must pay the full firm capacity price. However, under UNC0728C, shippers continue to benefit from the shorthaul capacity discount even when they do not use this capacity to nominate flows.

UNC0728C effectively allows shipper to book shorthaul capacity as there is less of a penalty associated with booking more capacity than is needed. However, the definition of the shorthaul product under all variants allows shippers to benefit from the shorthaul discount for capacity booked using all products, including the daily and within day products. Given this, on a gas system with growing spare capacity, we would expect shippers to be able to profile shorthaul capacity bookings against their flow requirements effectively. While the incentive is less sharp than under the other modification options, even under UNC0728C there is a disincentive to book shorthaul capacity that is not used for flows. Overbooking of capacity would still be avoided by shippers where possible.

This assessment aligns with our general assumption that capacity bookings are made to meet flow requirements. While there may be commercial reasons for tending towards overbooking or underbooking in specific cases, these are not incorporated in our modelling.

We therefore consider that the results observed for UNC0728 in previous analysis provide a reasonable representation of what we might expect to observe under UNC0728C but that there are some nuanced differences. For example, risk averse shippers who are eligible for the shorthaul product may prefer UNC0728C because the penalties for overbooking of shorthaul capacity are lower.

We do not model these differences in full. However, in this section, we summarise results from a sensitivity in which we assume a level of overbooking under UNC0728C. We model three levels of assumed overbooking: 5%,10% and 15%. Under each, we estimate the impact that this level of overbooking would have on revenue recovery contributions and the consequential impact on non-shorthaul tariffs.

Impact on revenue recovery

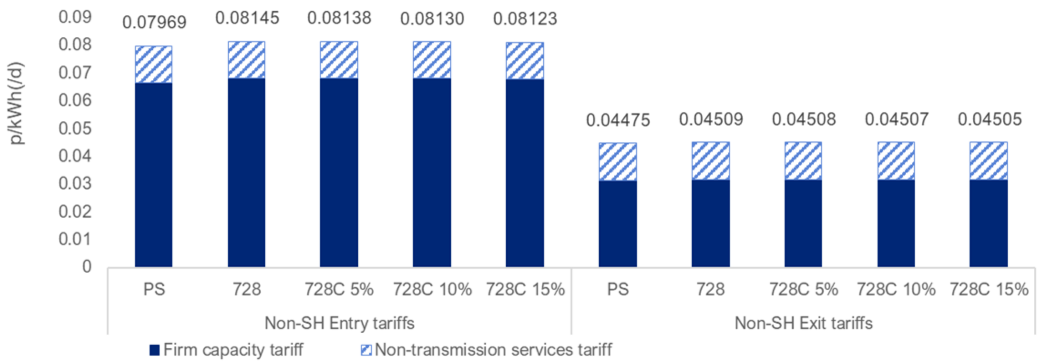
In the case that shorthaul users overbook capacity under UNC0728C, shorthaul capacity bookings would increase. Hence, revenue recovery contributions would also increase. We summarise the impacts on revenue recovery based on assumptions of overbooking of 5%, 10% and 15% in Table 3.1.

Table 3.1: Impacts of overbooking on revenue recovery (UNC0728C)

Overbooking assumption	SH capacity tariff revenue (£m)
728	12.71
728C 5%	13.28
728C 10%	13.84
728C 15%	14.40

These additional revenue contributions would reduce the revenue which needed to be recovered from non-shorthaul shippers, impacting on non-shorthaul tariffs. We summarise the tariff impacts of overbooking on non-shorthaul entry and exit tariffs in Figure 3.20.

Figure 3.20: Impact of overbooking on non-shorthaul tariffs



The impact on non-shorthaul tariffs is relatively small. With a 15% overbooking assumption, the impact on entry tariffs is less than 0.3% and the impact on exit tariffs is less than 0.1% of the equivalent tariff with no overbooking assumption included.

We note that UNC0728C could have alternative impacts to those considered above. For example, it is possible that some level of overbooking would exist under all modification options, particularly if shippers are risk averse. In this case, any overbooking under the alternative options would provide a more significant contribution to revenue recovery than it would under UNC0728C.

In addition, UNC0728C may reduce the likelihood that shorthaul shippers book less capacity than they need (underbooking) given the reduced risk associated with overbooking. Where shippers did underbook capacity, they would need to ‘top up’, using the firm or interruptible capacity product. In this case, they would contribute more towards revenue recovery than under UNC0728C where they can book more capacity than they need with little risk. It could therefore be argued that UNC0728C could reduce rather than increase revenue recovery contributions from shorthaul shippers.

Whether UNC0728C increases or decreases overbooking, the ability for shippers to profile shorthaul capacity bookings to flow requirements suggests that the impacts on non-shorthaul shippers may be relatively small.

4. SECOND ORDER EFFECTS RESULTING FROM POTENTIAL BYPASS

Up until this point, our analysis has focused on the first order effects of the options. As a result of the shorthaul discount available to eligible users, we found that the tariffs for non-shorthaul users increased. The direct tariff impacts and the upwards pressure on the wholesale gas price led to negative consumer welfare impacts under all options.

However, it is possible that users may choose to bypass the NTS to avoid paying the transmission tariff. If users do choose to bypass, this would reduce the amount of capacity contributing to recovery of allowed revenue, both from non-shorthaul and any shorthaul eligible flows on that route. The reduction in revenue contributions would raise the transmission tariff for all remaining users of the NTS and could lead to an increase in wholesale gas prices.

Therefore, depending on the risk of bypass, this suggests there may be a 'tipping point'. The 'first order' consumer detriment of providing a shorthaul product may be outweighed by the welfare benefit associated with avoiding system bypass.

In this section, we consider the second order effects – i.e. the potential for a shorthaul discount to prevent bypass, ensure revenue recovery from a greater volume of capacity and avoid an associated increase in tariffs for those connected to the NTS.

Noting particular challenges and uncertainties inherent within the analysis of bypass (see Section 2.1.4), we analyse the potential likelihood of system bypass under the counterfactual, and consider the reduction in that risk that the options may deliver. We use this to develop two sensitivities within which we estimate the impacts on gas transmission tariffs and the welfare impacts of any increase in the exit tariff.

We note the potential for 'third order effects'. The increase in tariffs which may result from bypass of the NTS could make it more profitable for other offtakers to invest in bypass pipelines, though this would only be the case where the investment case was already relatively marginal. At least in theory, this could create a feedback loop in which the incentives to bypass increase as more users decide to do so. We do not model these third order effects because they would be heavily assumptions driven.

4.1. Approach

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 route. We analysed whether investment in a bypass pipeline would be profitable within a five-year time horizon for all routes in the list compiled by NGGT for the purposes of UNC728.

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. For this analysis, we assumed that users would choose to bypass where they could recover the costs of their investment in the bypass pipeline within five years.

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 used a similar approach for our assessment of UNC0678. The counterfactual that was analysed under UNC0678 included a wide and generous shorthaul product (the optional commodity charge (OCC). Nevertheless, our analysis demonstrated a risk of bypass under the UNC0678 counterfactual for several routes. This reinforces our view that the estimated risk of bypass presented here is likely to be an overestimate of the actual risk. We consider it more appropriate to focus on the relative change in risk between the options rather than the absolute level of risk under any one option.

While the design of one option may reduce the risk of bypass, we note that the starting bypass risk is likely to already be low in many cases. If the risk of bypass is already very low under the counterfactual, and as noted above it may be an overestimate, then many of the benefits discussed in this section may be less relevant. When considering the impacts on tariffs and consumer welfare, we therefore explore a high and a low case sensitivity for the potential extent of bypass risk (Section 4.3).

4.2. Bypass investment

Impact on risk of bypass

In Table 4.1,we present estimates of the number of routes and volume of capacity that our modelling suggests present a risk of bypass under each option.

Capacity constraints at entry points mean that some eligible shorthaul offtakers are not able to use the shorthaul product for the full amount of capacity that they need. Where bypass occurs, a proportion of the capacity bookings would have been made using the non-shorthaul as well as the shorthaul product.

Table 4.1: Number of routes and capacity bookings that present a risk of bypass assuming a five-year payback time based on our modelling (CT, 2030-31)

Tariff option	Number of routes that present a credible risk of bypass[35]	Volume of capacity bookings that present a credible bypass risk (shorthaul and non-shorthaul, TWh/year)
Status quo	12	110.6
UNC0728	10	106.3
UNC0728A	6	93.3
UNC0728B	10	106.3
UNC0728D	3	36.9

This analysis suggests that UNC0728 and UNC0728B may lead to a small reduction in the likelihood of bypass. However, the inclusion of the Non-Transmission Services Charge in UNC0728A and UNC0728D drives a more significant reduction in bypass risk.

UNC0728D provides the greatest reduction in bypass risk. This implies that the majority of those routes that are most likely to bypass under the status quo are within the 5 km eligibility criteria, included under UNC0728D.

4.3. Bypass sensitivities

In the previous section, we considered the number of routes and total flows that present a risk of bypass based on our modelling. Given the scope of uncertainties and assumptions which are built into our analysis, we suggest caution in drawing conclusions about how this bypass risk may manifest in consequential impacts on tariffs and ultimately, consumer welfare.

Nevertheless, we develop an indicative analysis of these effects in this section. We consider two bypass sensitivities. Under the high bypass sensitivity, we assume that all routes that were determined to present a risk of bypass under our modelling choose to do so. Under this sensitivity, we do not incorporate any information other than our modelling to consider bypass risk.

[35] We modelled a total of 29 routes.

As we have previously signalled, we expect our modelling of bypass to result in overestimates of the likelihood of bypass risk. For this reason, Ofgem asked us to test the impact of bypass under an additional sensitivity. Under this sensitivity, Ofgem has used private information, not available to CEPA, to develop a view on the likelihood of bypass for each individual route, under each option. Under this 'low bypass' sensitivity we take Ofgem's view on the likelihood of bypass rather than our modelling to determine the potential impact on tariffs and gas consumer welfare. Ofgem asked us to only model the status quo, Option UNC0728B and UNC0728D using this approach.

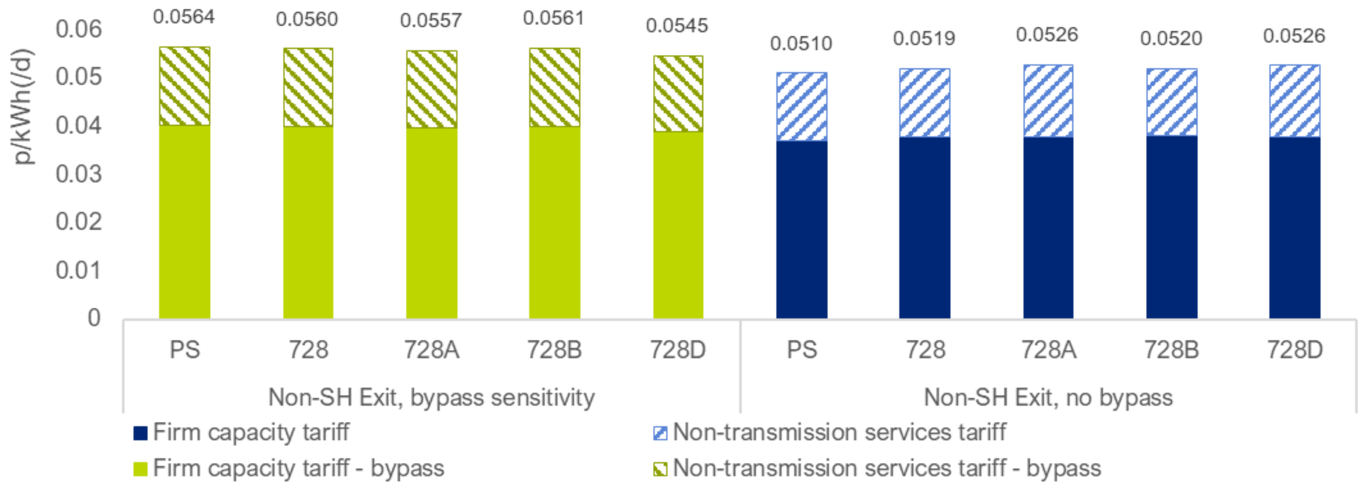
4.3.1. Sensitivity 1: High bypass sensitivity

Under the high bypass sensitivity, we assume that all routes choose to bypass where our modelling indicates that they may profitably do so.

Impacts on tariffs

We present the impacts of bypass on the tariffs under our high bypass sensitivity in Figure 4.1. The exit tariffs after including bypass are presented on the left while the tariffs without consideration of bypass are presented on the right.

Figure 4.1: Impacts of bypass on exit tariffs (high bypass sensitivity) – Exit, non-shorthaul (2030-31, £m 2018/19)



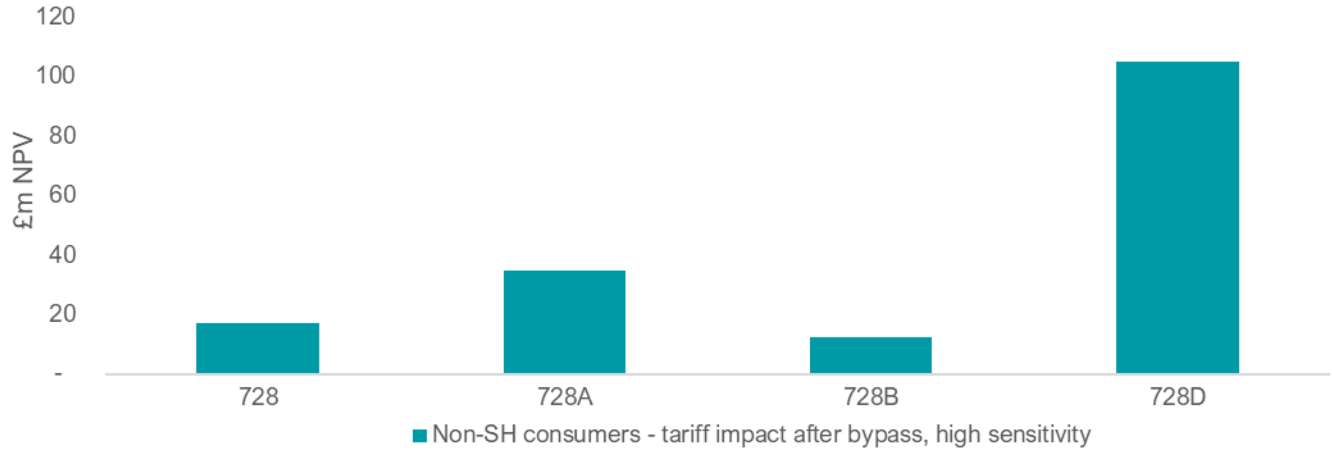
The chart shows that the exit tariff for non-shorthaul consumers is higher under all options when risk of bypass is not considered (the right-hand side of the chart). However, by reducing the risk of bypass, it is possible for non-shorthaul consumers to benefit from the provision of a shorthaul discount (the left-hand side) under UNC0728 and variants. The chart shows that the 'tipping point' is reached under all options. I.e. the benefit of preventing bypass and retaining revenue contributions outweighs the lost revenue from provision of the shorthaul tariff discount in all cases.

This also shows that, at least under the high bypass sensitivity, Option D results in the greatest reduction in the tariff relative to the status quo thanks to the reduction in bypass risk. While UNC0728D leads to the highest tariff when bypass is not considered, it also leads to the greatest reduction in risk of bypass and hence, to the lowest non-shorthaul tariff after incorporating the modelled risk of bypass.

Impacts on consumer welfare

By considering the impact on exit tariffs across the full modelled period from 2022-23 we can estimate the potential impact that including consideration of bypass would have on consumer welfare. We estimate the more direct exit tariff effect only. We do not re-model the impact that bypass may have on the gas wholesale market price (or the electricity market price). We estimate the consumer welfare impact of the change to the exit tariff in Figure 4.2.

Figure 4.2: Second order effect of bypass on the exit tariff and consumer welfare (high bypass sensitivity), (NPV, 2022-31, £m 2018/19)[36]



Based on modelled estimates of bypass risk, the chart shows the potential benefit resulting from the reduction in potential bypass under UNC0728D in particular. Despite this option resulting in a higher exit tariff before incorporating potential bypass, the reduction in bypass risk means that a greater proportion of capacity remains on the system. The other options also provide some benefit through reduced bypass risk.

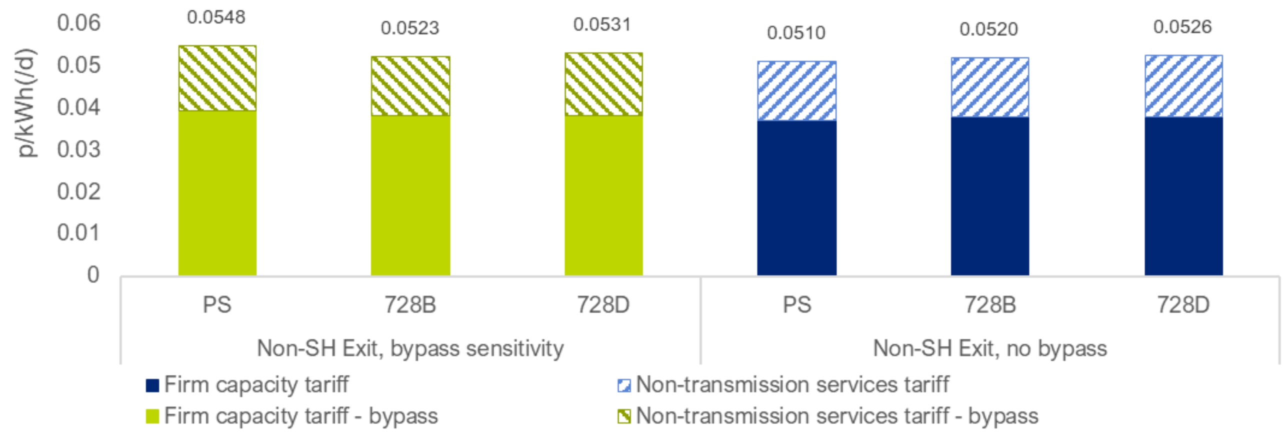
4.3.2. Sensitivity 2: Low bypass sensitivity

Under the low bypass sensitivity, we define the risk of bypass for each route based on Ofgem's analysis under options UNC0728B and UNC0728D, as well as for the status quo. Ofgem identified eight routes that it considers to be at risk of bypass under the status quo. Under both UNC0728B and UNC0728D, Ofgem's analysis suggests that the risk of bypass would reduce to two routes. The two routes that Ofgem identifies as being at risk of bypass are different for each of the options.

Impacts on tariffs

We present the impacts of bypass on the exit tariffs under Ofgem's low bypass sensitivity in Figure 4.3. The tariffs after including bypass are presented on the left while the tariffs before considering bypass are presented on the right.

Figure 4.3: Impacts of bypass on tariffs (low bypass sensitivity) – Exit, non-shorthaul (2030-31, £m 2018/19)



[36] NB: For the avoidance of doubt, this consumer welfare impact cannot be considered additional to the welfare impacts set out in Figure 3.11. In that consumer welfare chart, we presented exit tariff and gas price impacts as observed without considering bypass. However, the welfare impacts presented here provide a sense of the magnitude of the potential impact under the relevant sensitivity.

As for the high bypass sensitivity, we find that the exit tariffs for non-shorthaul shippers are lower under the options than under the status quo once the risk of bypass is considered. Under the high bypass sensitivity, we found that Option UNC0728D resulted in the lowest exit tariff based on modelled estimates of avoided bypass. However, under the low bypass sensitivity, we find that it is Option UNC0728B that results in the lowest exit tariff after considering bypass.

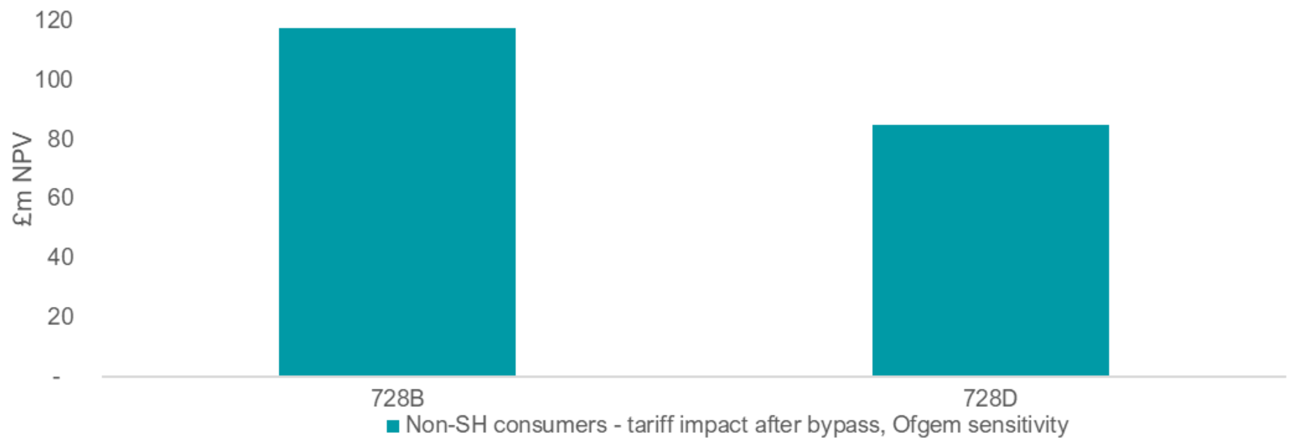
The change in the tariff is a consequence of the revenue contributed from those routes that do not bypass. We find a higher tariff under UNC0728D for two reasons:

1. The initial exit tariff for non-shorthaul users is initially higher before taking bypass into account.
2. The loss of revenue from routes that choose to bypass under Option UNC0728D is greater than the loss of revenue from routes that choose to bypass under UNC0728B, primarily as a result of the volume of bookings and flows for the exit points that choose to bypass under each option.

Impacts on consumer welfare

As for the case of the high bypass sensitivity, we present the potential impacts of bypass on consumer welfare, considering only the direct effect on the exit tariff. We present these results in Figure 4.4. The NPV consumer welfare results are taken across the full modelled period (2022-31).

Figure 4.4: Second order effect of bypass on the exit tariff and consumer welfare (low bypass sensitivity), (NPV, 2022-31, £m 2018/19)[37]



Due to the impact on the exit tariff, we find that the consumer welfare benefits of avoided bypass under Option UNC0728B are greater than under UNC0728D. Welfare impacts are of a similar order of magnitude to those observed under the high bypass sensitivity.

4.4. CLUSTERING

Ofgem has received representations from several stakeholders to suggest that they may decide to bypass as a cluster. This would mean sharing the additional costs of a bypass pipeline and the use of that pipeline with other offtakers by building a common pipeline to a nearby entry point. After reviewing these representations, Ofgem asked us to model three potential groups of exit points that they considered could cluster based on these representations.

We assessed the likelihood of bypass of these clusters under each of the options, adopting the same approach as that we used to consider bypass more generally. We assumed that the pipeline would be built to meet the

[37] We use the same scale on the y-axis to allow for comparability with the high bypass scenario

combined capacity of the exit points and used the straight line distance approach to model the length of the pipeline.

We modelled three clustering groups with corresponding straight line distances determined as the longest required by any of the exit points included:

- Cluster 1, longest route distance = close to 30 km,
- Cluster 2, longest route distance = over 80 km, and
- Cluster 3, longest route distance = under 5 km.

We set out whether our modelling suggests these clusters would choose to bypass based on a five-year payback time in Table 4.2.

Table 4.2: Clustering: Modelled expectation of potential bypass (five year payback time)

Tariff option	Cluster 1	Cluster 2	Cluster 3
Status quo	Yes	No	Yes
UNC0728	Yes	No	Yes
UNC0728A	Yes	No	No
UNC0728B	Yes	No	No
UNC0728D	Yes	No	No

We note several points in considering the likelihood of bypass of these clusters.

- **Cluster 1**: We have previously noted the limitations in our analysis that we only incorporate straight line distances, rather than the specific requirements of a bypass pipeline. In the case of the exit points that may build a bypass pipeline as part of cluster 1, we note that offtakers sit on the other side of a river estuary relative to their nominated entry point. While we are not able to estimate the impact that this would have on the costs of a bypass pipeline, we expect that this would have a significant impact on the likelihood of bypass in practice.
- **Cluster 2**: Several of the exit points that have suggested they may bypass as part of cluster 2 have indicated this as an alternative to bypassing as part of cluster 1. This is despite a significantly longer pipeline distance, which may indicate that cost-wise this presents an alternative to building a pipeline across a river estuary. We note however that the nominated entry point for cluster 2 has insufficient capacity to meet the full amount of demand of the exit points in this cluster. This suggests that there may be capacity constraints for these offtakers in some periods, during which they would continue to require some capacity from the NTS.
- **Cluster 3**: The offtakers that have suggested they may bypass as part of cluster 3 are small industrial sites (based on gas consumption in recent years). While the route distance of the pipeline is under 5km, the small capacity requirements coupled with economies of scale of the bypass pipeline reduce the likelihood of bypass. This helps explain why the risk of bypass is more marginal. We only observe a risk of bypass under the status quo and UNC0728, but not under the other options.

Appendix A DETAILED RESULTS

In this appendix, we present detailed results for all gas years.

A.1. Consumer Transformation

A.1.1. Tariff impacts

Figure A.1: Annual weighted average tariffs at non-SH entry points (Central case (CT), 2022-23, £18/19)

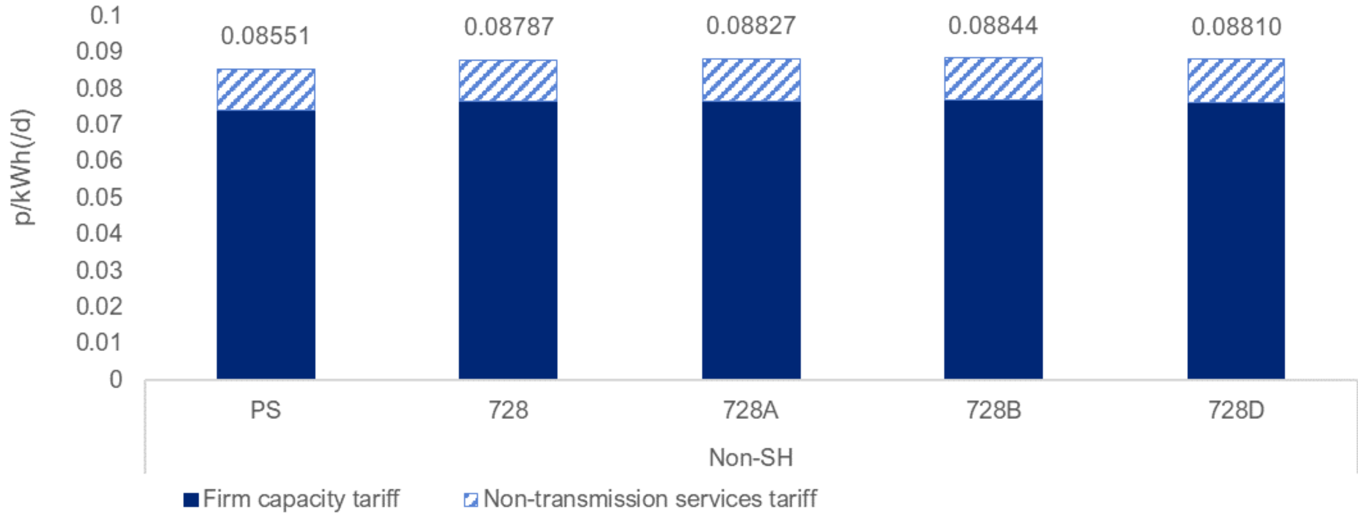
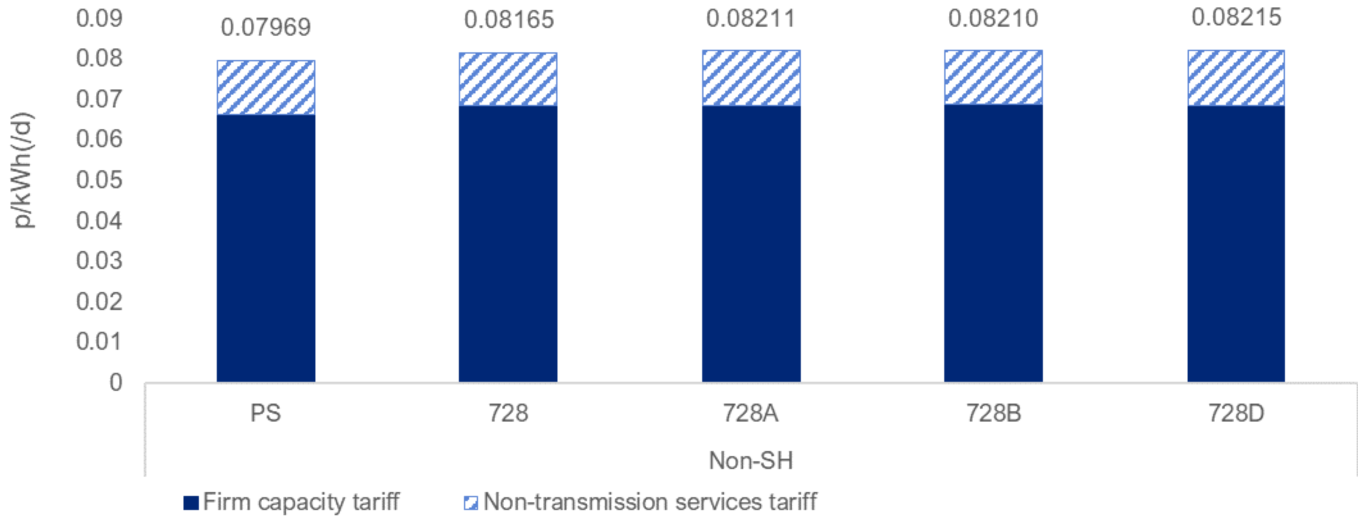


Figure A.2: Annual weighted average tariffs at non-SH entry points (CT, 2026-27, £18/19)



See Figure 3.2 for the annual weighted average tariffs at non-SH entry points under each option for CT, 2030-31.

Figure A.3: Annual weighted average tariffs at non-SH exit points (Central case (CT), 2022-23, £18/19)

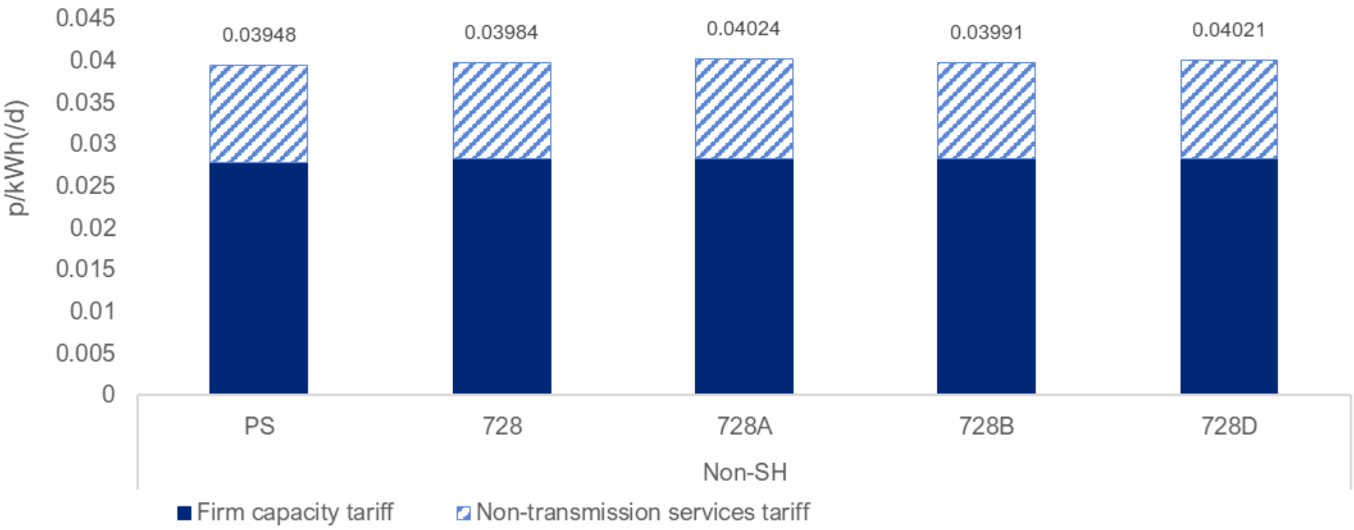
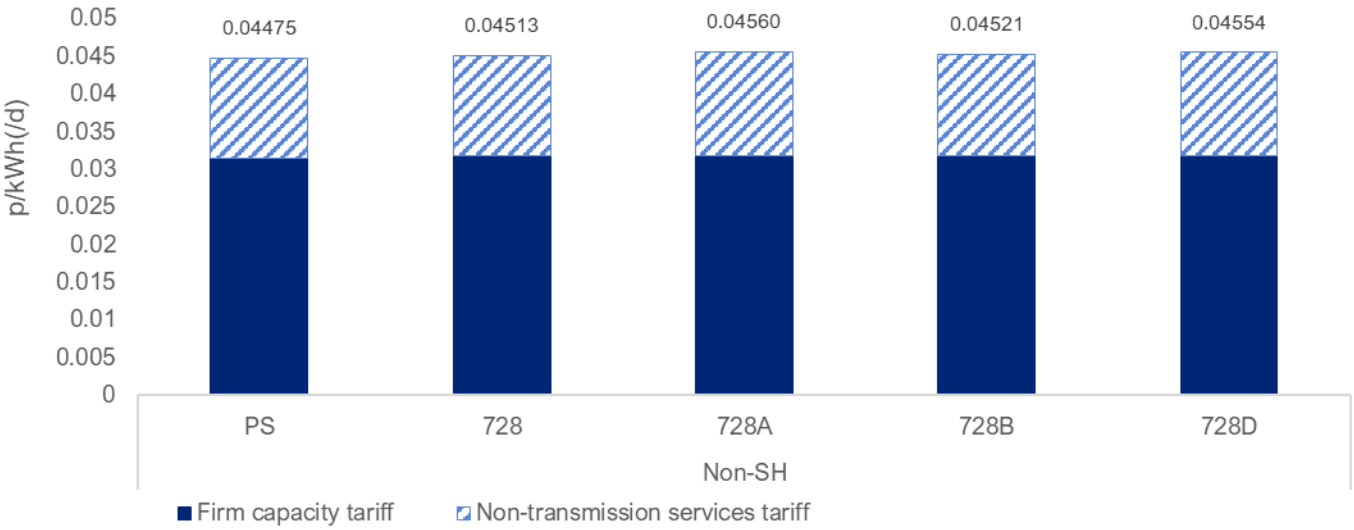


Figure A.4: Annual weighted average tariffs at non-SH exit points (CT, 2026-67, £18/19)



See Figure 3.4 for the annual weighted average tariffs at non-SH exit points for CT, 2030-31.

Figure A.5: Annual weighted average capacity tariffs at storage entry and exit points (Central case (CT), 2022-23, £18/19)

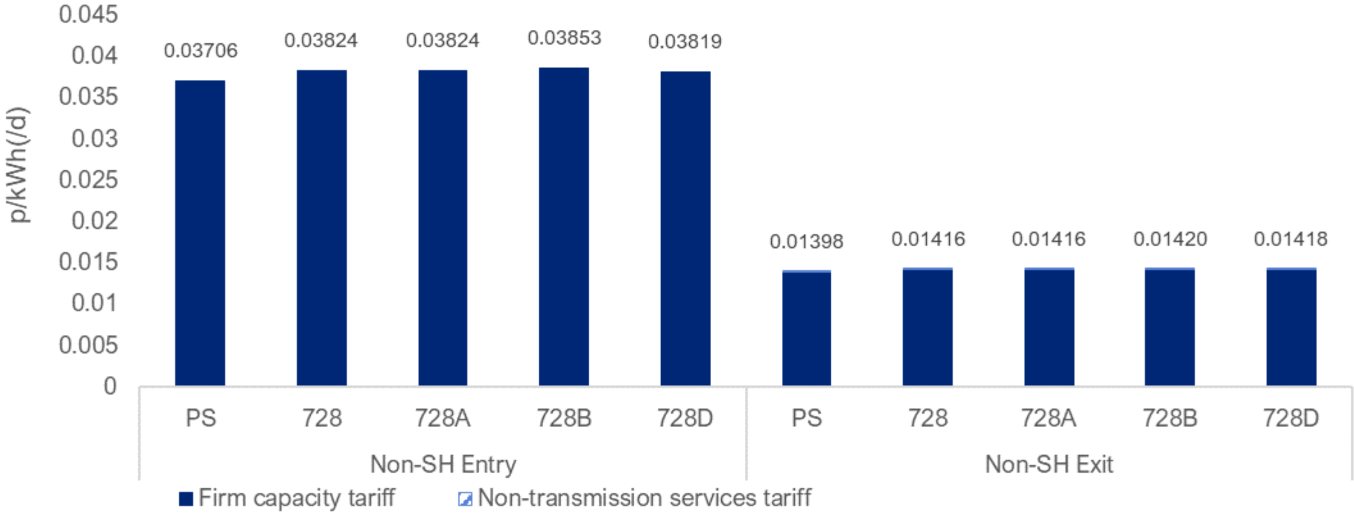
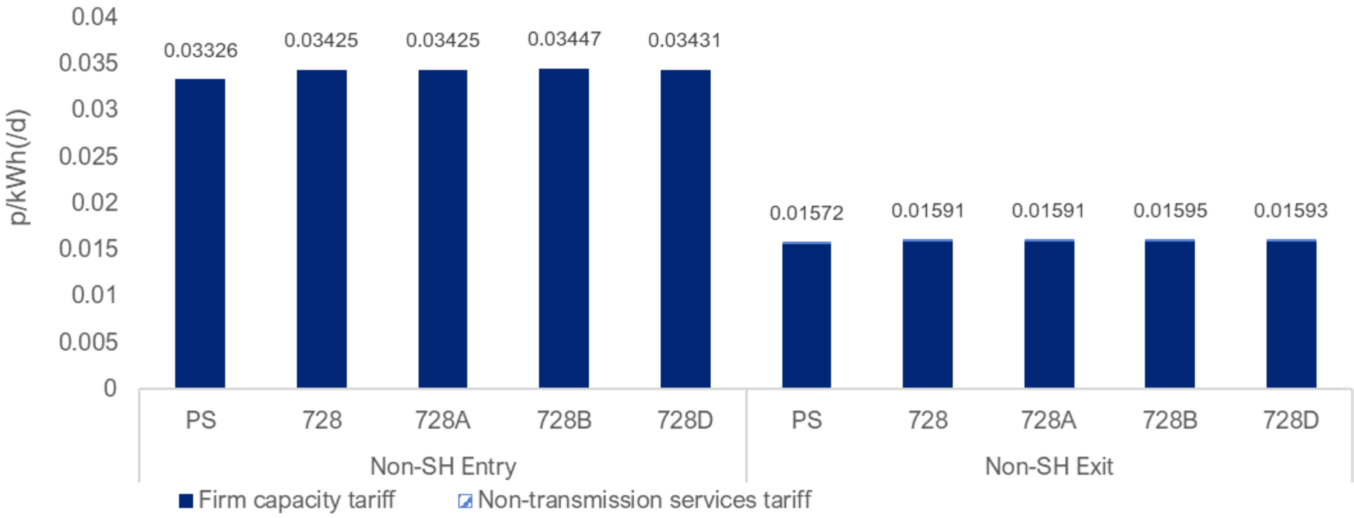


Figure A.6: Annual weighted average capacity tariffs at storage entry and exit points (CT, 2026-27, £18/19)



See Figure 3.5 for annual weighted average capacity tariffs at storage entry and exit points for CT, 2030-31.

Figure A.7: Annual weighted average capacity tariffs at interconnector entry and exit points (Central case (CT), 2022-23, £18/19)

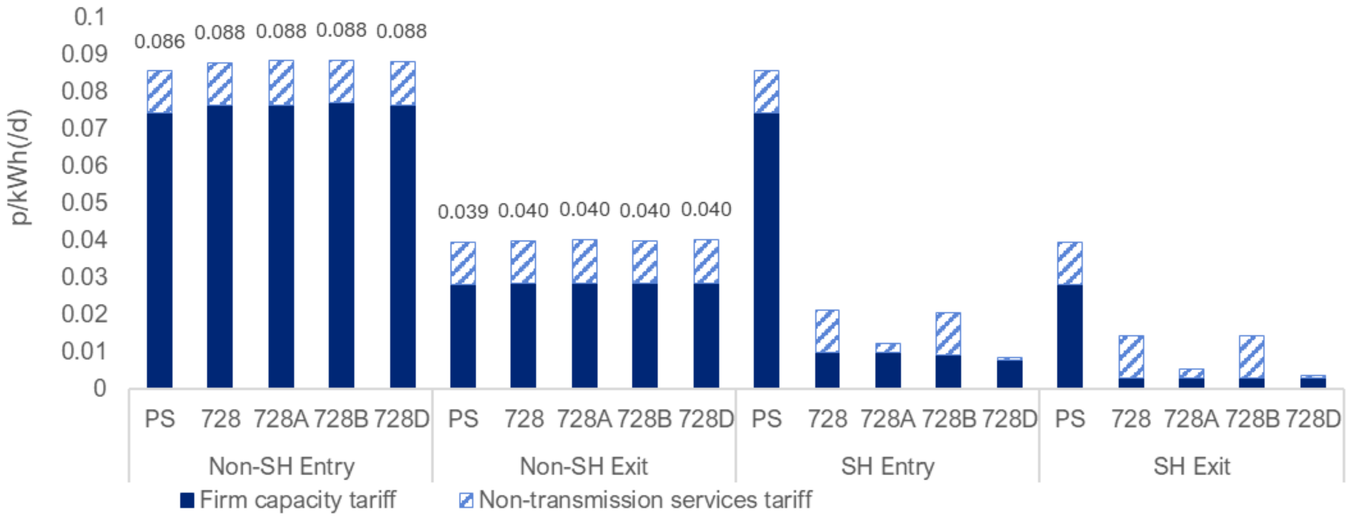
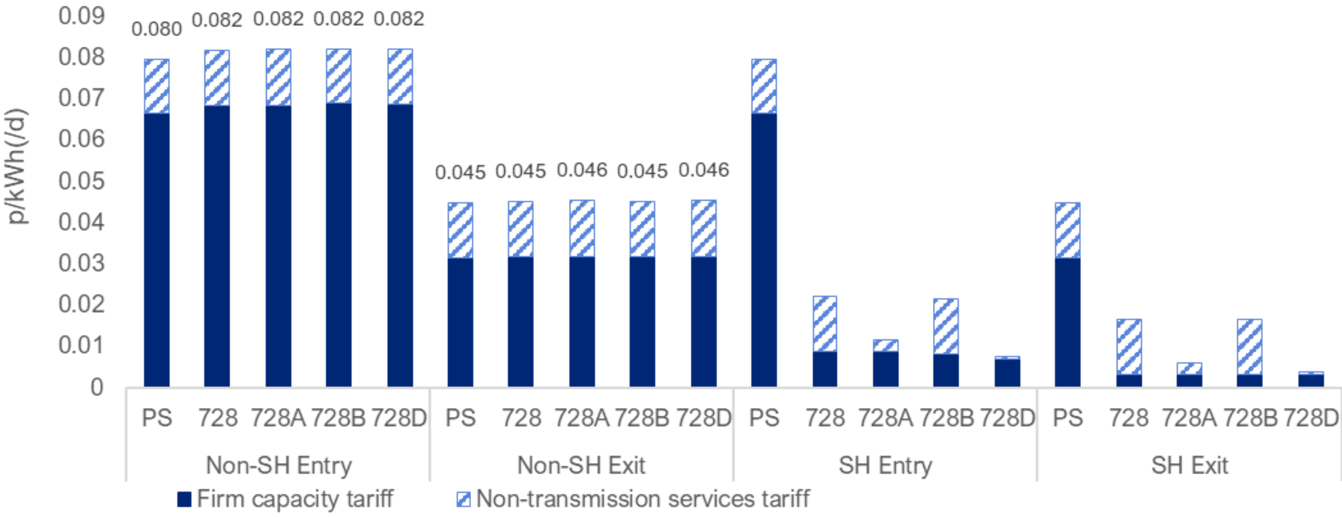


Figure A.8: Annual weighted average capacity tariffs at interconnector entry and exit points (CT, 2026-27, £18/19)



See Figure 3.6 for annual weighted average capacity tariffs at interconnector entry and exit points for CT, 2030-31.

A.1.2. Gas and electricity market price impacts

Figure A.9: Estimated gas market price impacts (Central case (CT), 2022-23, £18/19)

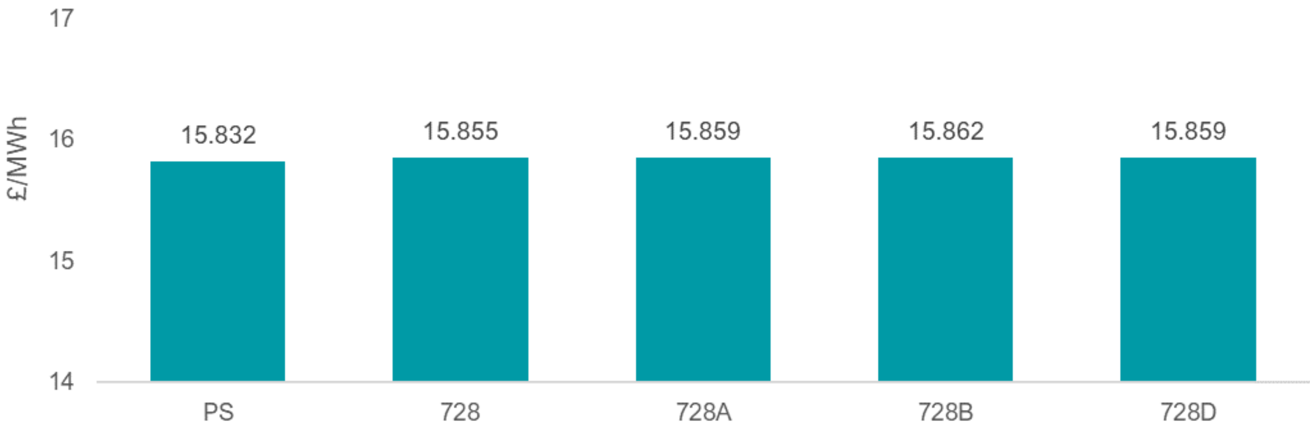
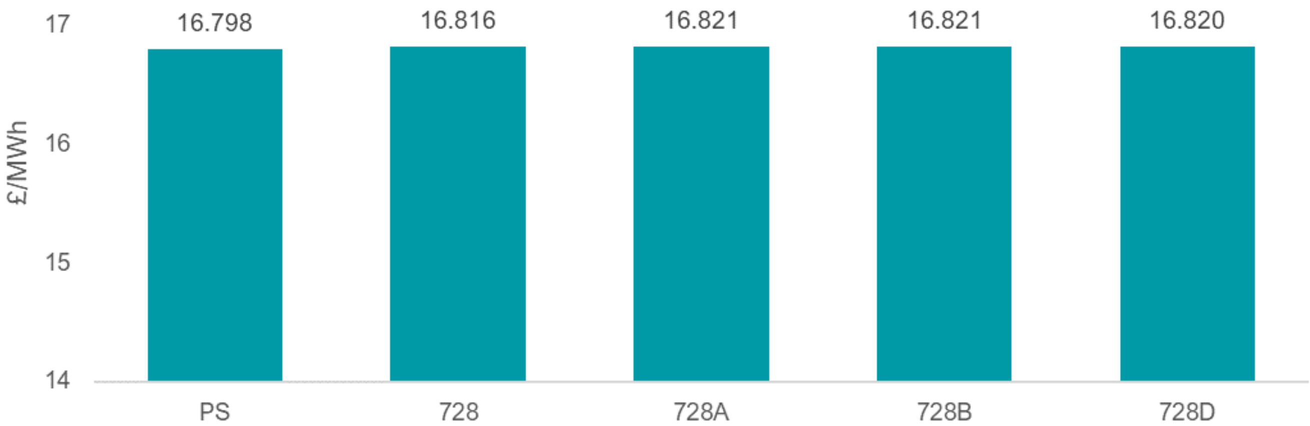


Figure A.10: Estimated gas market price impacts (CT, 2026-27, £18/19)



See Figure 3.8 for the estimated gas market price impacts for CT, 2030-31.

Figure A.11: Simulated wholesale electricity prices (Central case (CT), 2022-23, £18/19)

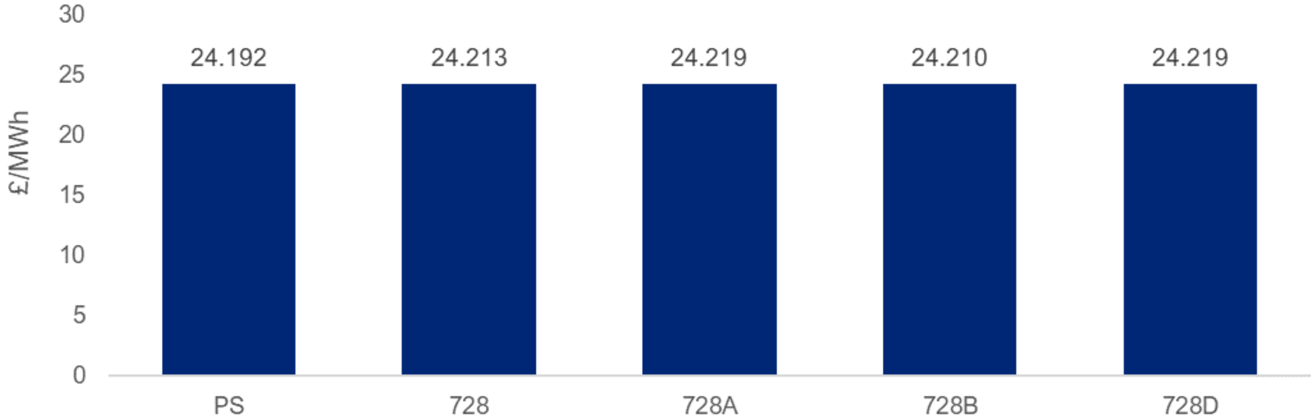
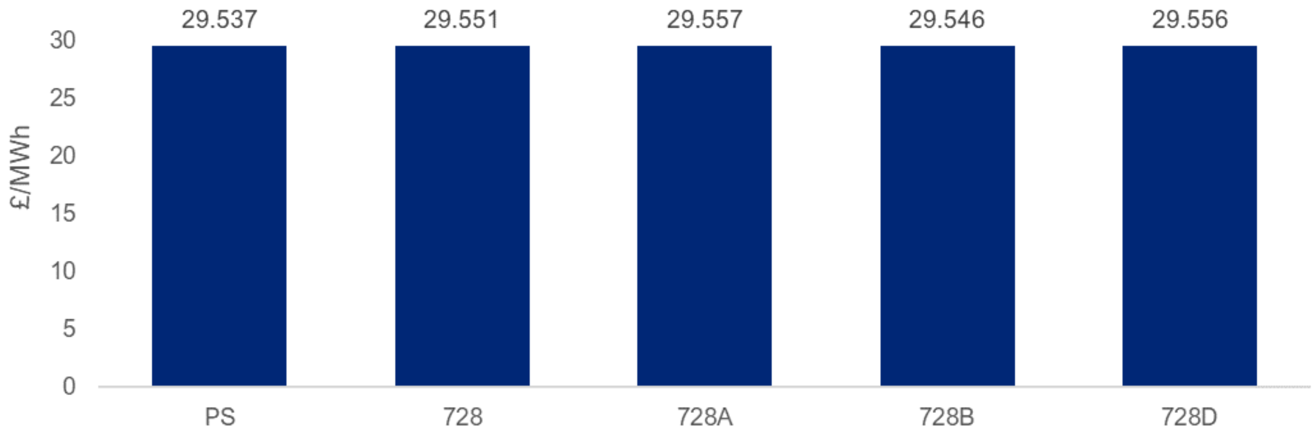


Figure A.12: Simulated wholesale electricity prices (CT, 2026-27, £18/19)



See Figure 3.8 for the simulated wholesale electricity prices for CT, 2030-31.

A.1.3. Consumer welfare

See Figure 3.9 and Figure 3.10 for gas and electricity consumer welfare impacts (CT, 2022-2031, NPV, discounted to £18/19).

A.1.4. Bill impacts

Figure A.13: Estimated bill impact for median consumption domestic gas consumers (Central case (CT), 2022-23, £18/19)

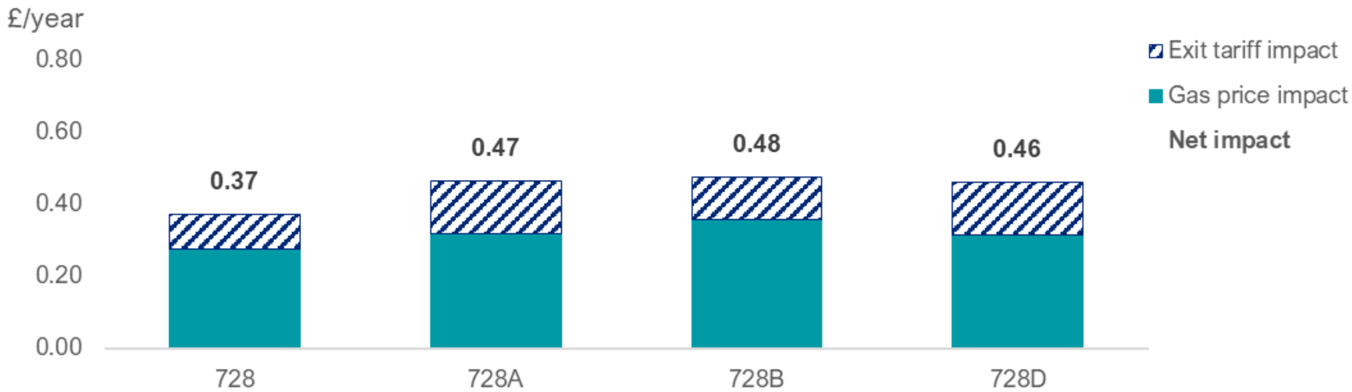
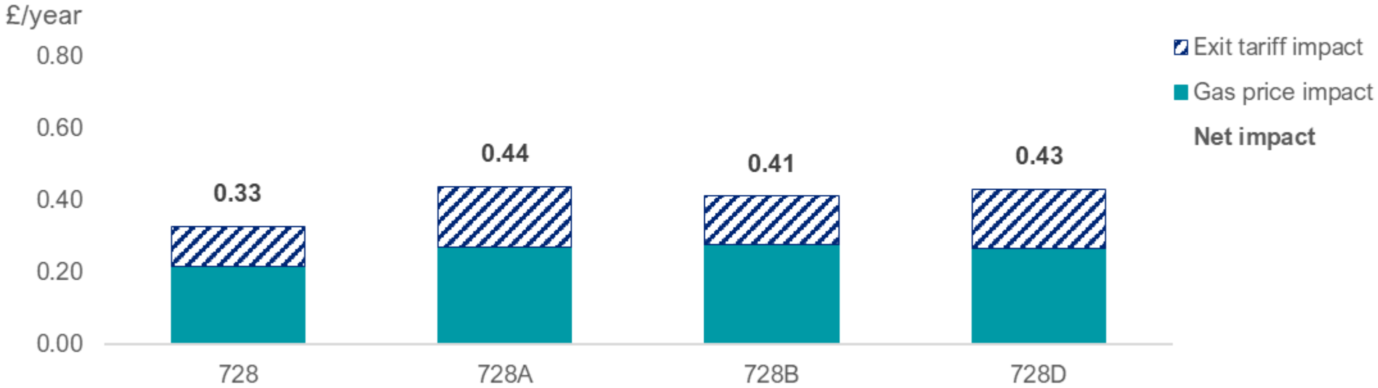


Figure A.14: Estimated bill impact for median consumption domestic gas consumers (CT, 2026-27, £18/19)



See Figure 3.11 for estimated bill impact for median consumption domestic gas consumers for CT, 2030-31.

Figure A.15: Estimated bill impact for median vulnerable domestic gas consumers (Central case (CT), 2022-23, £18/19)

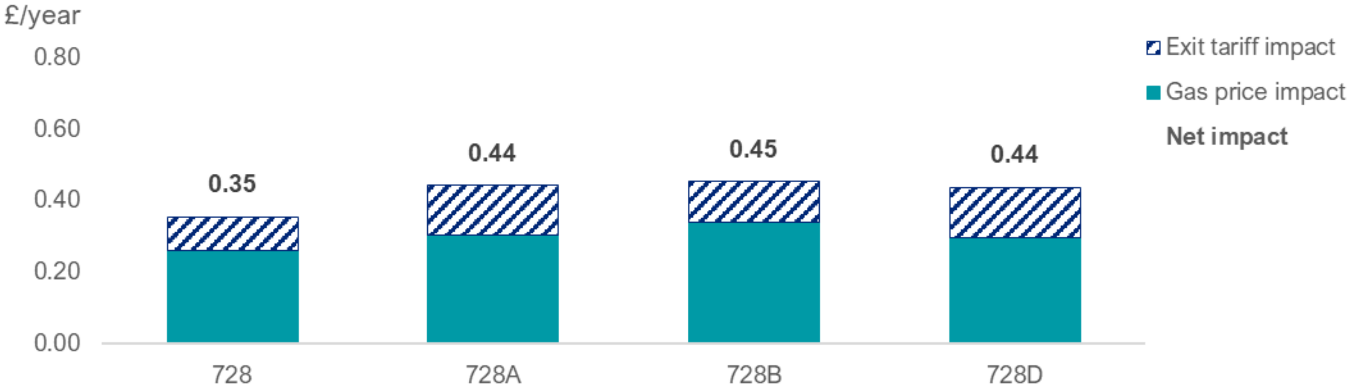
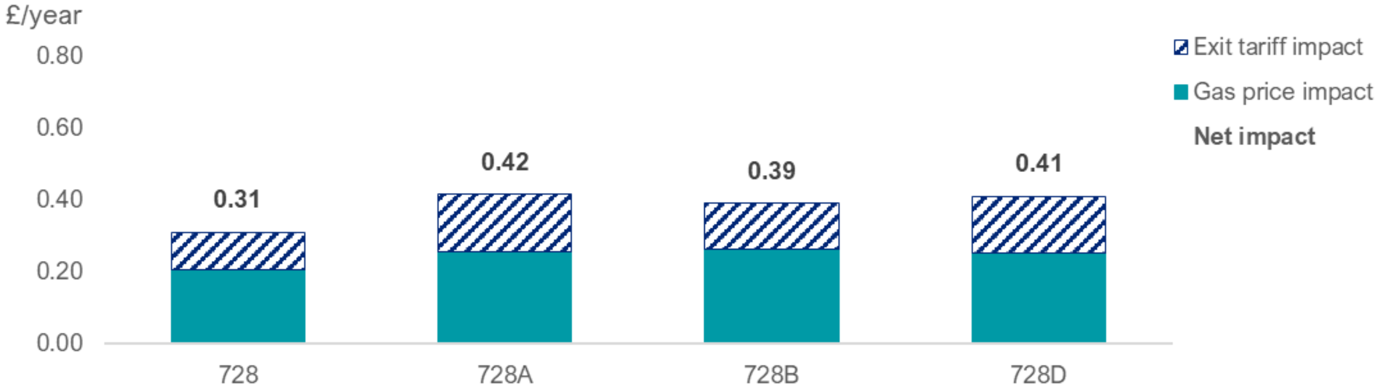


Figure A.16: Estimated bill impact for median vulnerable domestic gas consumers (CT, 2026-27, £18/19)



See Figure 3.12 for estimated bill impact for median vulnerable domestic gas consumers for CT, 2030-31.

Figure A.17: Estimated bill impact (gas only) for the median non-domestic consumer connected to the LDZ (Central case (CT), 2022-23, £18/19)

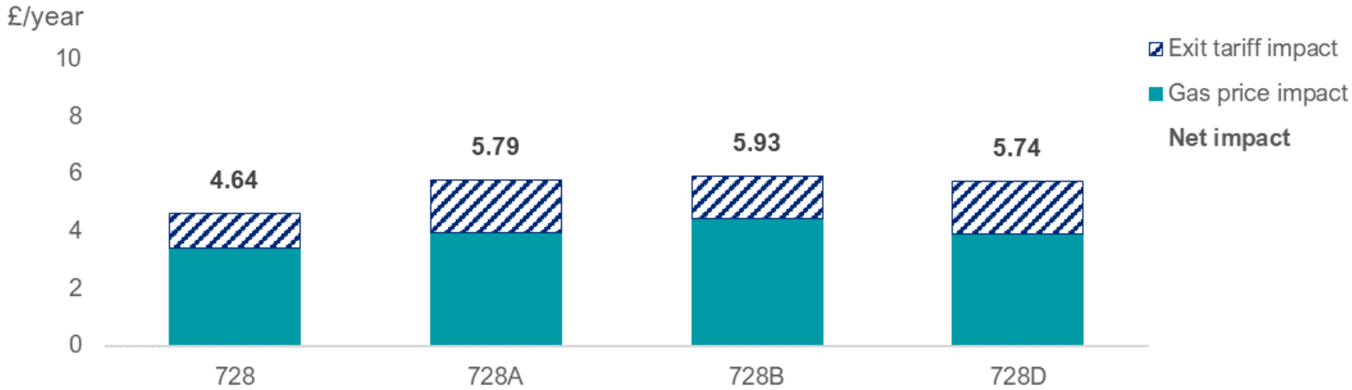
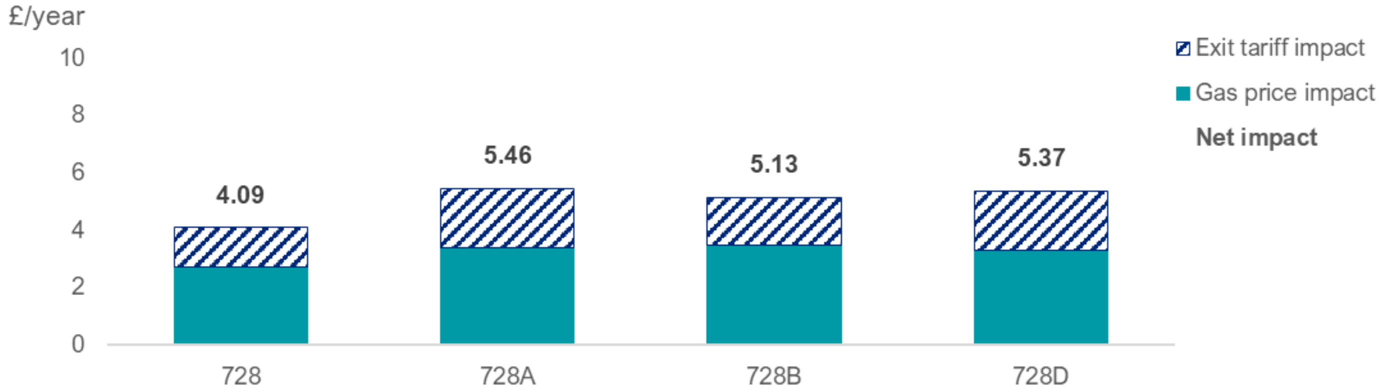


Figure A.18: Estimated bill impact (gas only) for the median non-domestic consumer connected to the LDZ (CT, 2026-27, £18/19)



See Figure 3.13 for estimated bill impact (gas only) for the median non-domestic consumer connected to the LDZ CT, 2030-31.

Figure A.19: Estimated bill impact (gas only) for the median non-domestic consumer connected to the NTS, not eligible for shorthaul (Central case (CT)*, 2022-23, £18/19)*

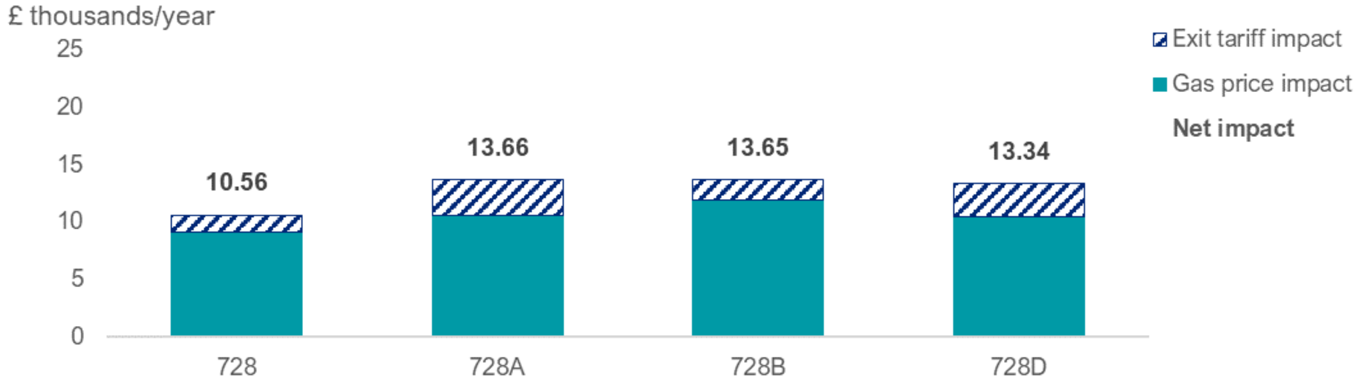
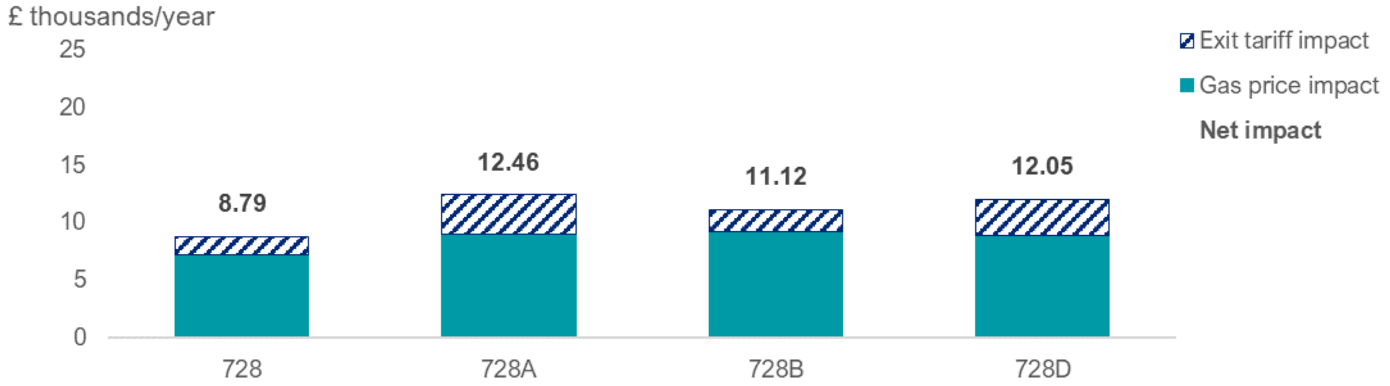


Figure A.20: Estimated bill impact (gas only) for the median non-domestic consumer connected to the NTS, not eligible for shorthaul *(CT, 2026-27, £18/19)*



See Figure 3.14 for the estimated bill impact (gas only) for the median non-domestic consumer connected to the NTS for CT, 2030-31.

Figure A.21: Estimated bill impact (gas only) for the median non-domestic consumer connected to the NTS, eligible for shorthaul and utilising the shorthaul product for 100% of its bookings/flows (Central case (CT)*, 2022-23, £18/19)*

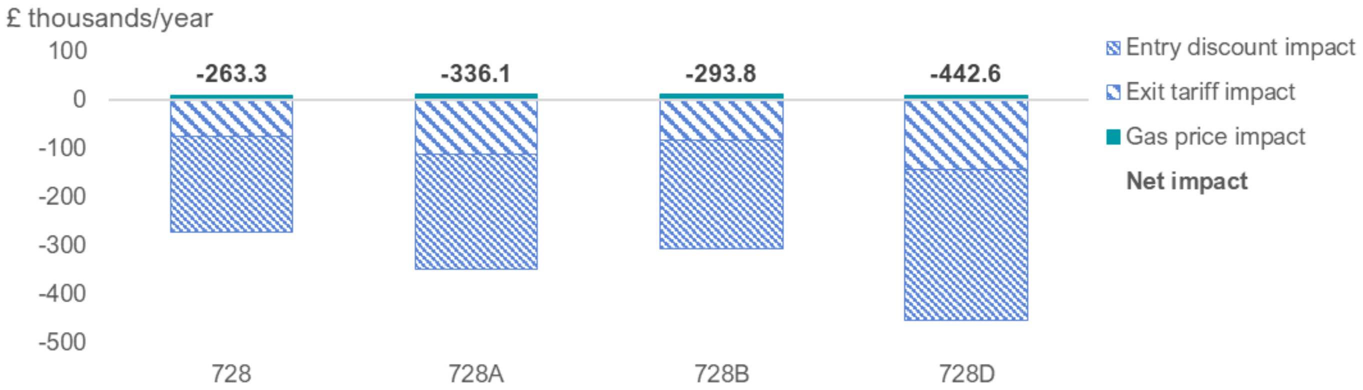
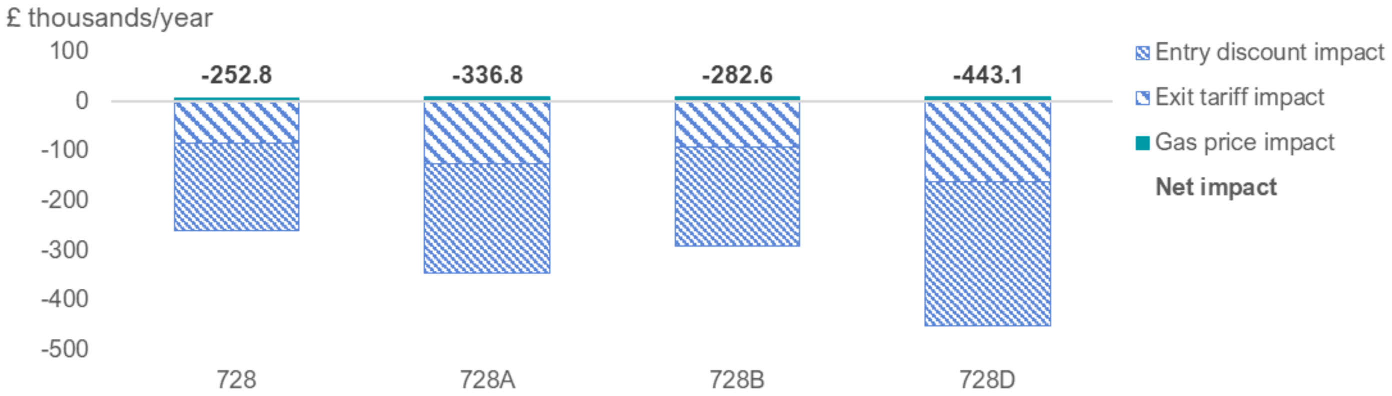


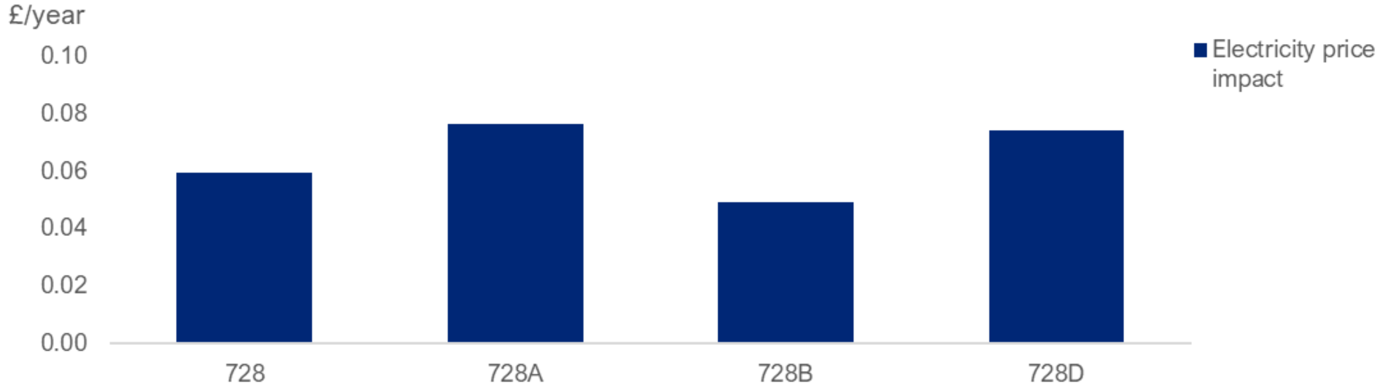
Figure A.22: Estimated bill impact (gas only) for the median non-domestic consumer connected to the NTS, eligible for shorthaul and utilising the shorthaul product for 100% of its bookings/flows (CT, 2026-27, £18/19)



See Figure 3.15 for the estimated gas bill impact for CT 2030-31 for the median non-domestic consumer connected to the NTS that is eligible for shorthaul and utilising the shorthaul product for 100% of its bookings/flows.

See also Figure 3.16 for the estimated bill impact for median consumption domestic electricity consumers for CT, 2030-31 (£18/19), and Figure 3.17 for the estimated bill impact for median consumption non-domestic electricity consumers for CT, 2030-31 (£18/19).

Figure A.23: Estimated bill impact for median vulnerable domestic electricity consumers (CT, 2030-31 £18/19)



A.1.5. Impacts on power stations and carbon emissions

See Figure 3.18 for impacts on gas-fired power stations (2022-2031, NPV, discounted to £18/19) and Figure 3.19 for impacts on the average annual CO2 emissions (CT, 2022-2031).

A.1.6. Impacts on producer, interconnector, and storage facility revenues

Table A.24: Impacts on total revenues of entry-only points, interconnectors, and gas storage facilities (NPV, 2022-2031, £m 2018/19)

£m NPV	728	728A	728B	728D
Entry-only points[38]				
Beach terminals				
Wholesale gas price impact	134.09	163.99	168.17	161.46
Entry tariff impact (incl. shorthaul tariffs)	-1.46	-1.46	-2.01	-1.02
Net impact	**132.64**	**162.52**	**166.16**	**160.44**
Onshore fields				
Wholesale gas price impact	0.52	0.62	0.66	0.62
Entry tariff impact (incl. shorthaul tariffs)	-0.02	0.00	-0.02	0.00
Net impact	**0.50**	**0.62**	**0.64**	**0.62**
LNG terminals				
Wholesale gas price impact	*No LNG flows over our modelling horizon under this scenario under any of the options, so no impacts.*			
Entry tariff impact (incl. shorthaul tariffs)				
Net impact				

[38] We estimate net impacts for producers and LNG terminals by pricing flows of entry gas at the prevailing wholesale gas price and subtracting estimated entry tariffs (including any shorthaul entry tariffs).

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 impact on producer surplus. This is a reasonable assumption given that upstream costs are unlikely to be affected by changes in the NTS charging methodology.

Interconnectors[39]				
Continental bi-directional interconnectors				
Wholesale gas price impacts (both entry and exit)	15.22	18.72	18.51	18.28
Tariff impacts (incl. shorthaul tariffs, both entry and exit)	-0.09	-0.10	-0.11	-0.10
Net impact	**15.13**	**18.62**	**18.40**	**18.19**
Moffat				
Wholesale gas price impact	0.99	2.07	1.18	1.94
Exit tariff impact (not eligible for shorthaul tariffs)	-1.05	-2.18	-1.19	-2.07
Net impact	**-0.05**	**-0.11**	**-0.02**	**-0.13**
Storage points[40]				
Wholesale gas price impacts (both entry and exit)	-1.07	-1.51	-1.29	-1.38
Tariff impacts (both entry and exit)	0.03	0.05	0.04	0.04
Operational cost impacts	0.76	0.88	0.91	0.85
Net impact	**-0.27**	**-0.59**	**-0.35**	**-0.49**

[39] We calculate net impacts for interconnectors by multiplying the gas flows over the interconnectors by the price differential between markets (depending on the direction of flow) and netting off the entry or exit tariffs under each option. Given a lack of cost data, we did not attempt to incorporate operational costs into our revenue estimates.

As before, this approach effectively focuses on shipper revenues.

[40] To estimate net impacts for storage facilities, 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.

A.2. Steady progression

A.2.1. Tariff impacts

Figure A.25: Annual weighted average tariffs at non-SH entry points (Central case (CT), 2022-23, £18/19)

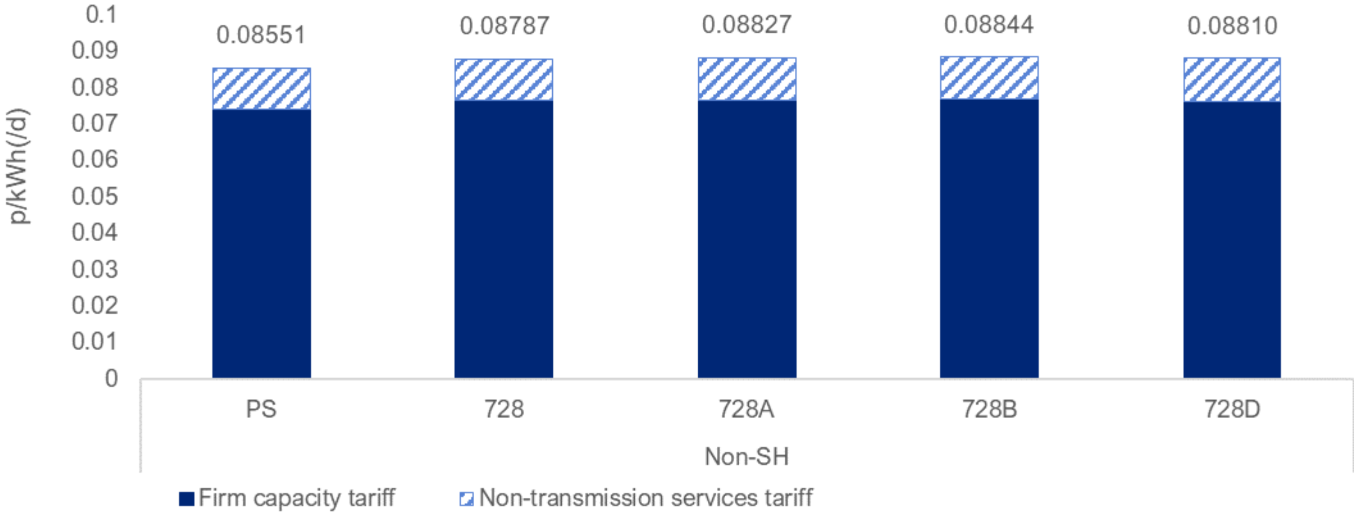


Figure A.26: Annual weighted average tariffs at non-SH entry points (SP, 2026-27, £18/19)

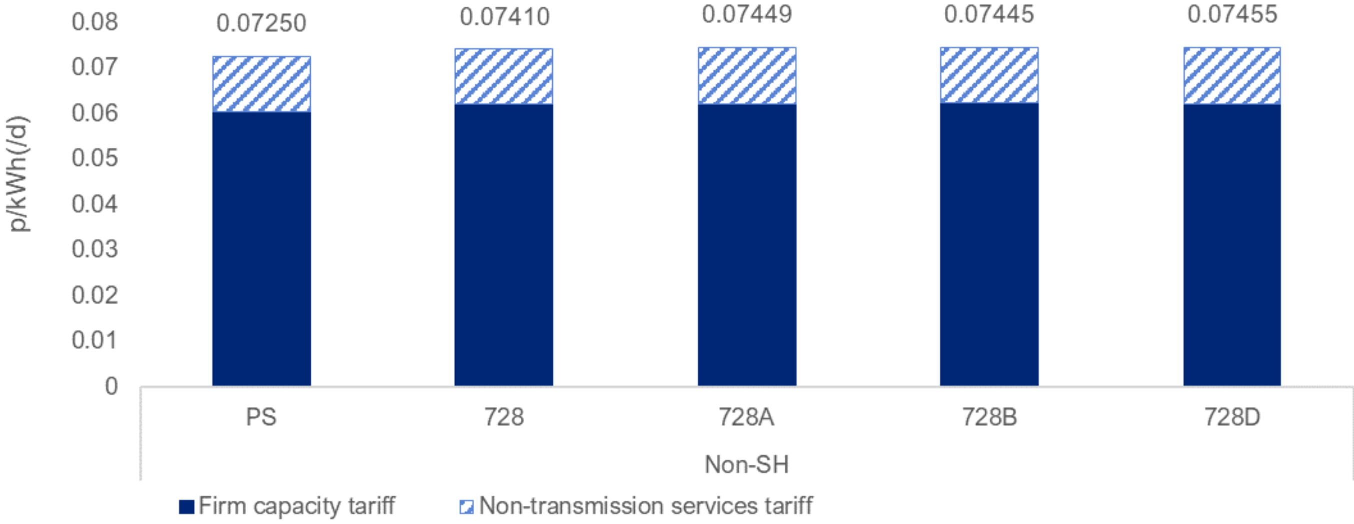


Figure A.27: Annual weighted average tariffs at non-SH entry points (SP, 2030-31, £18/19)

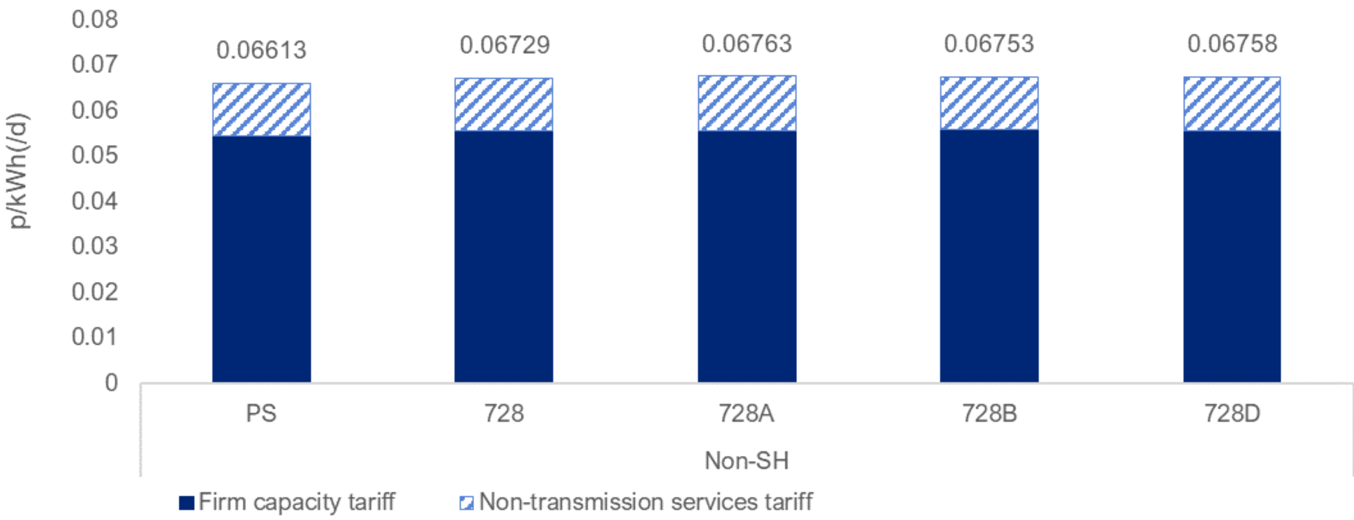


Figure A.28: Annual weighted average tariffs at non-SH exit points (Central case (CT), 2022-23, £18/19)

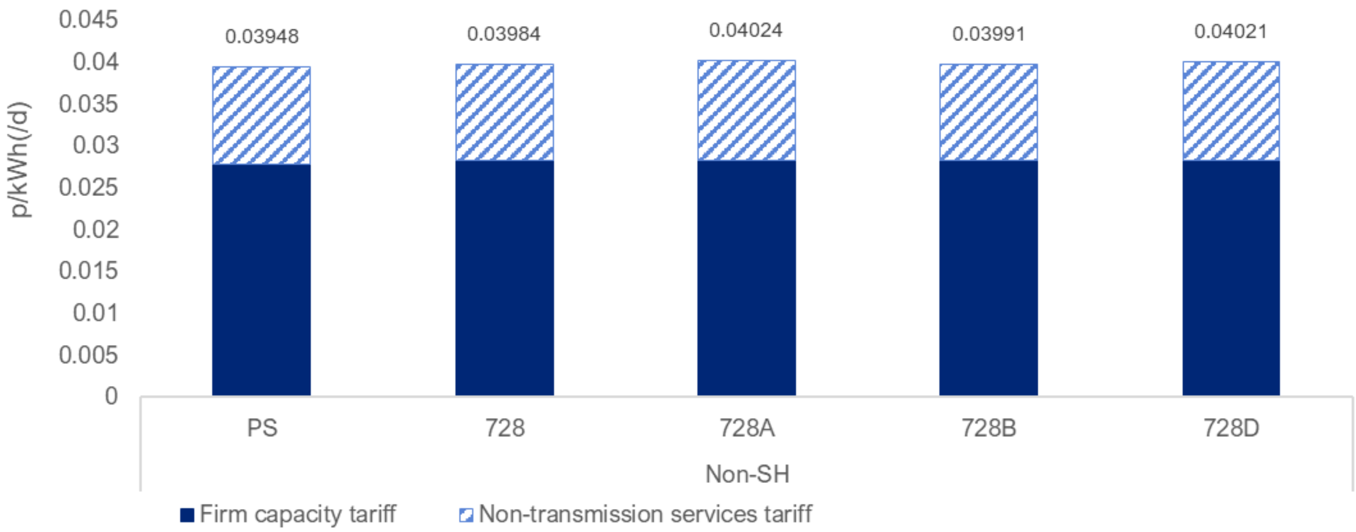


Figure A.29: Annual weighted average tariffs at non-SH exit points (SP, 2026-67, £18/19)

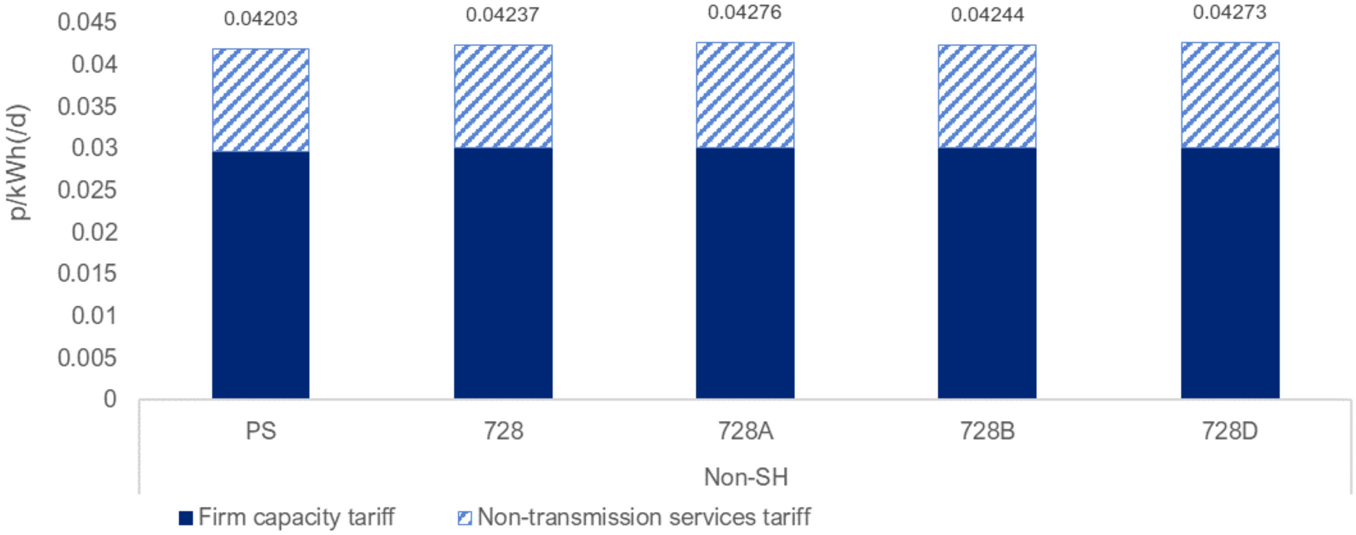


Figure A.30: Annual weighted average tariffs at non-SH exit points (SP, 2030-31, £18/19)

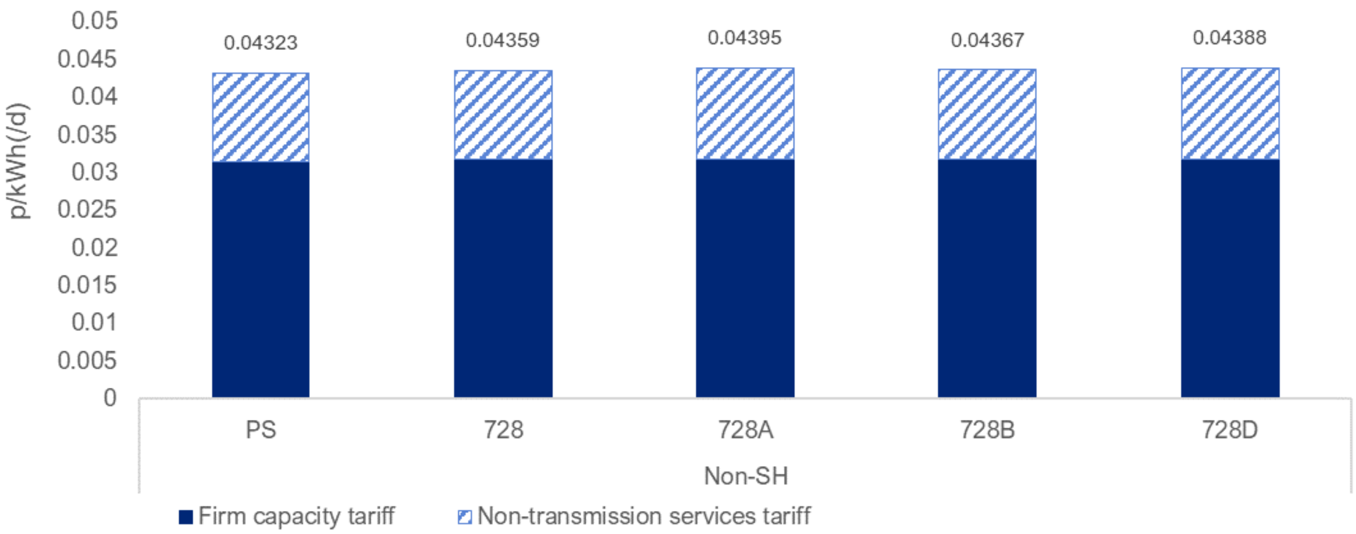


Figure A.31: Annual weighted average capacity tariffs at storage entry and exit points (Central case (CT), 2022-23, £18/19)

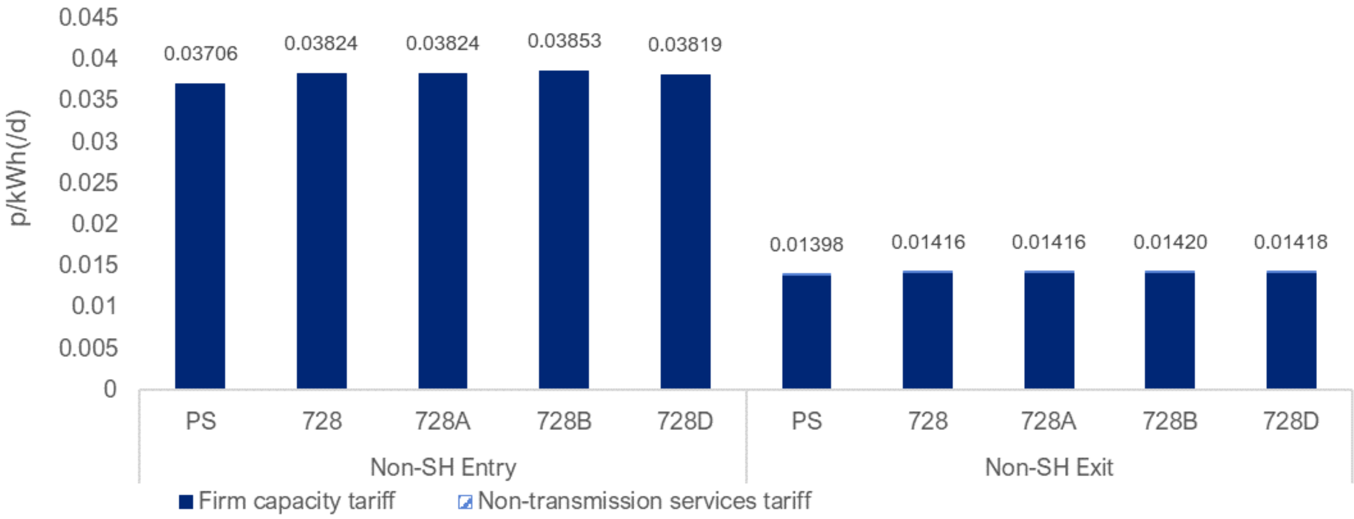


Figure A.32: Annual weighted average capacity tariffs at storage entry and exit points (SP, 2026-27, £18/19)

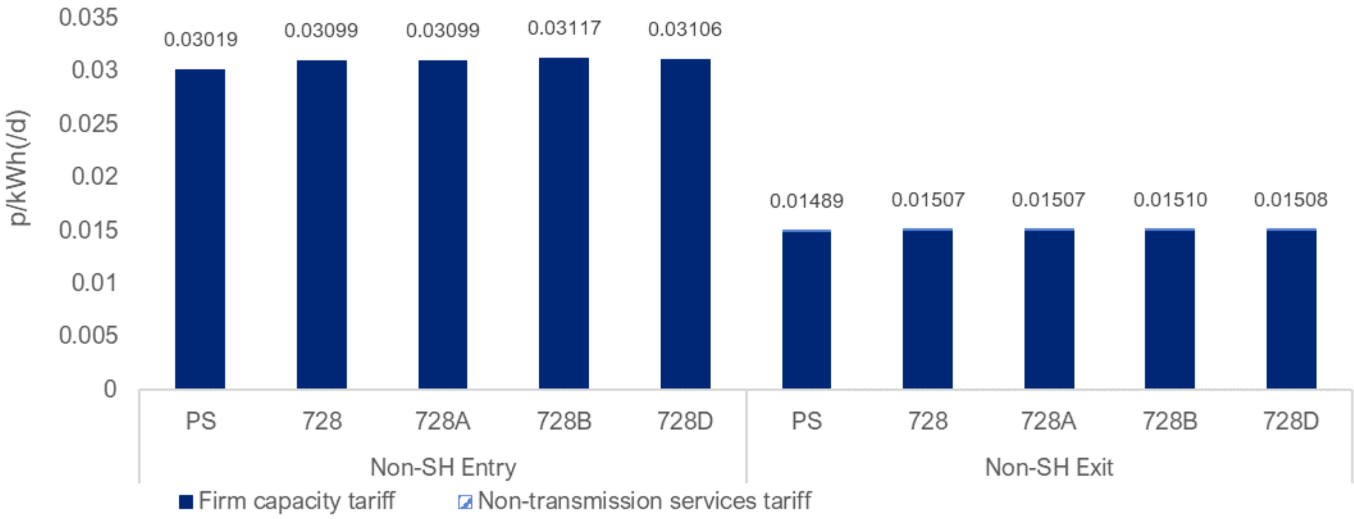


Figure A.33: Annual weighted average capacity tariffs at storage entry and exit points (SP, 2030-31, £18/19)

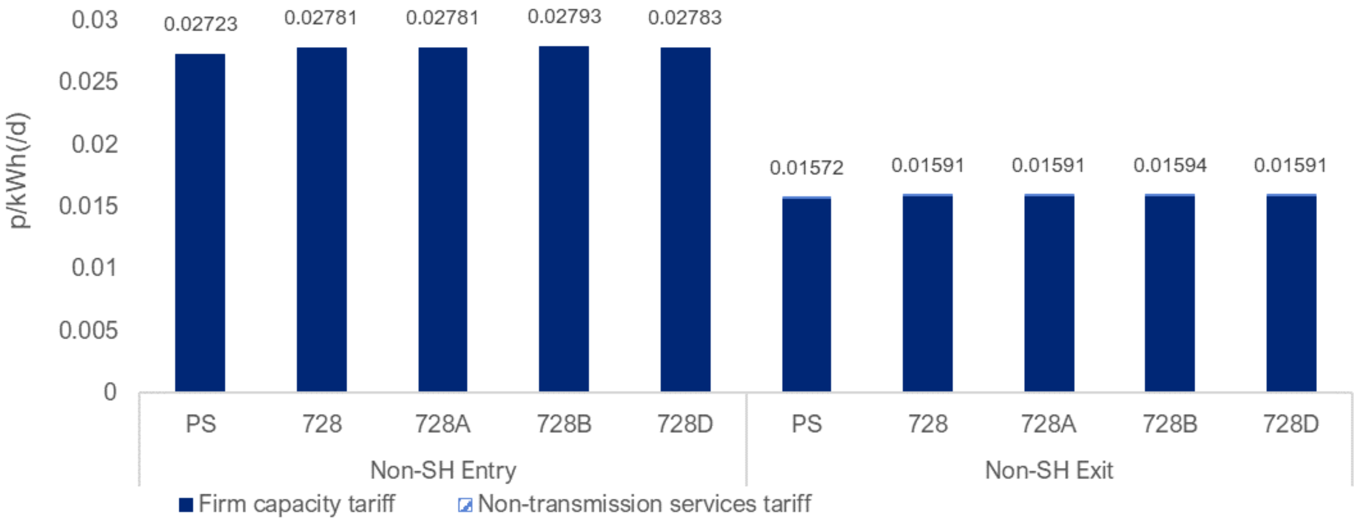


Figure A.34: Annual weighted average capacity tariffs at interconnector entry and exit points (Central case (CT), 2022-23, £18/19)

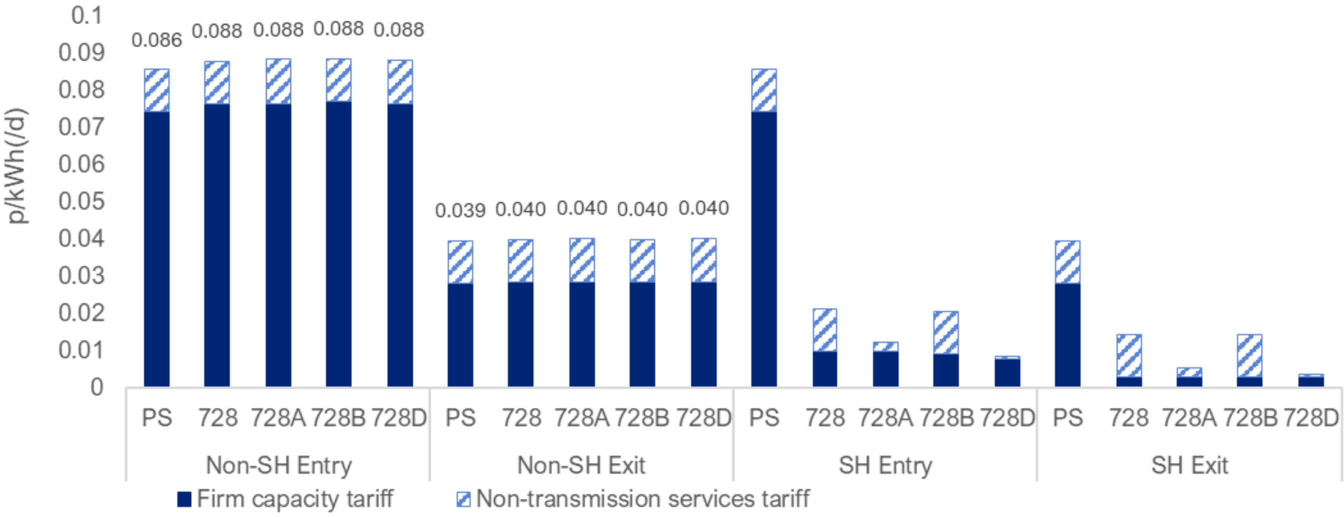


Figure A.35: Annual weighted average capacity tariffs at interconnector entry and exit points (SP, 2026-27, £18/19)

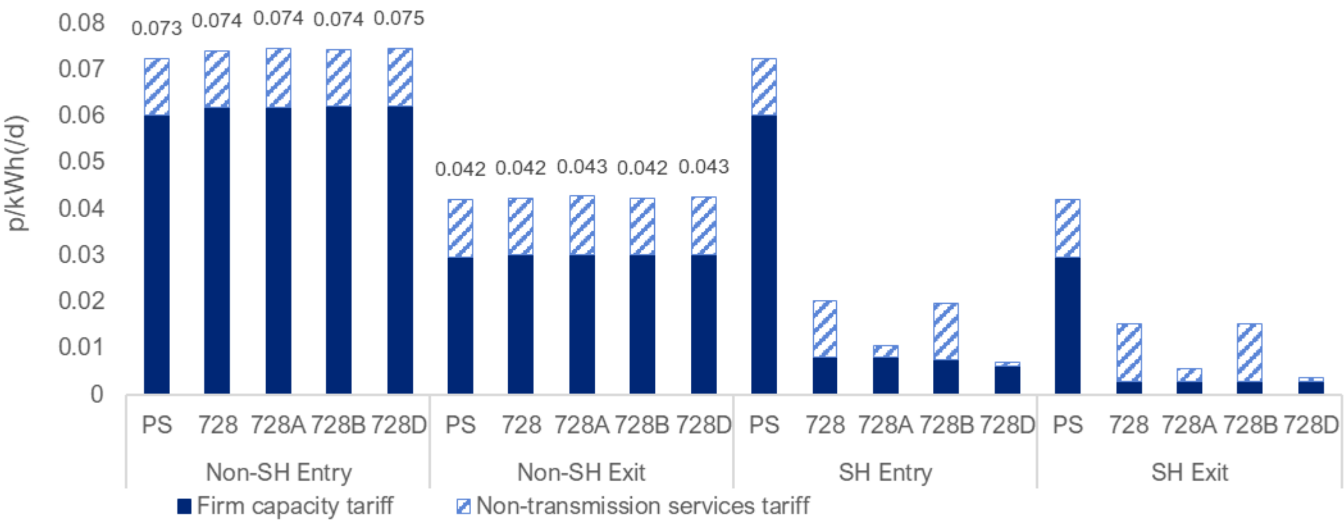
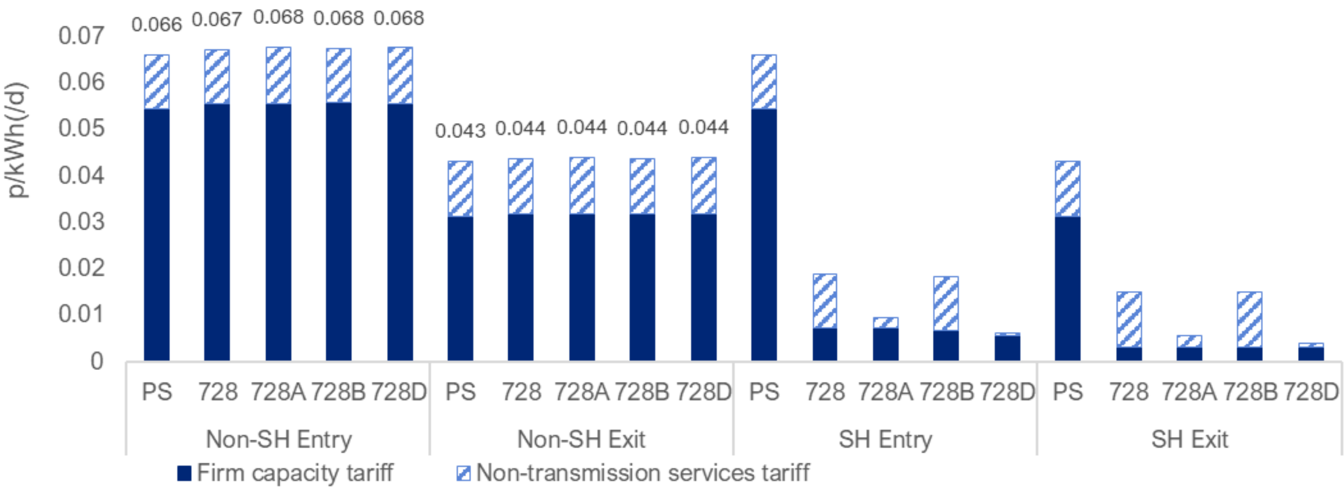


Figure A.36: Annual weighted average capacity tariffs at interconnector entry and exit points (SP, 2030-31, £18/19)



A.2.2. Gas and electricity market price impacts

Figure A.37: Estimated gas market price impacts (Central case (CT), 2022-23, £18/19)

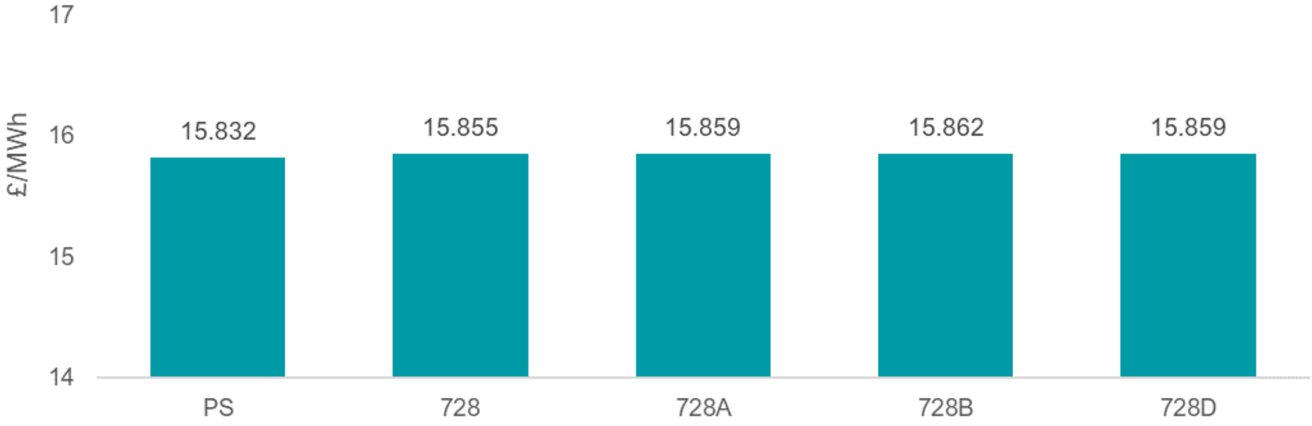


Figure A.38: Estimated gas market price impacts (SP, 2026-27, £18/19)

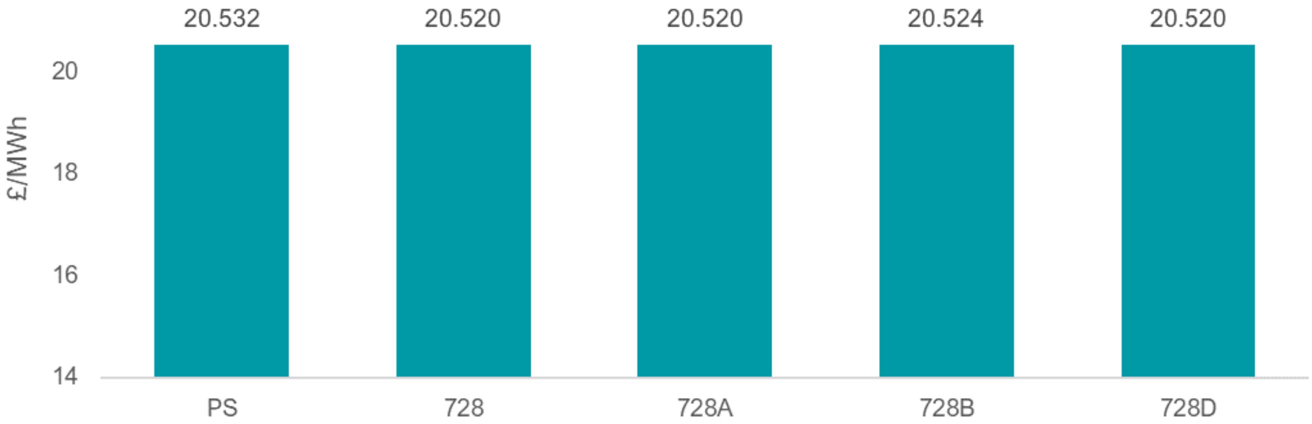


Figure A.39: Estimated gas market price impacts (SP, 2030-31, £18/19)

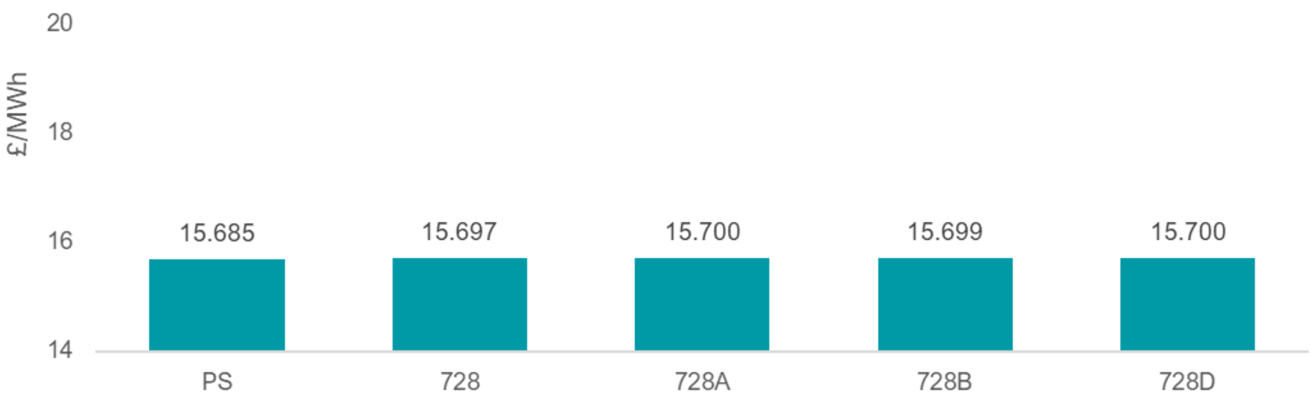


Figure A.40: Simulated wholesale electricity prices (Central case (CT), 2022-23, £18/19)

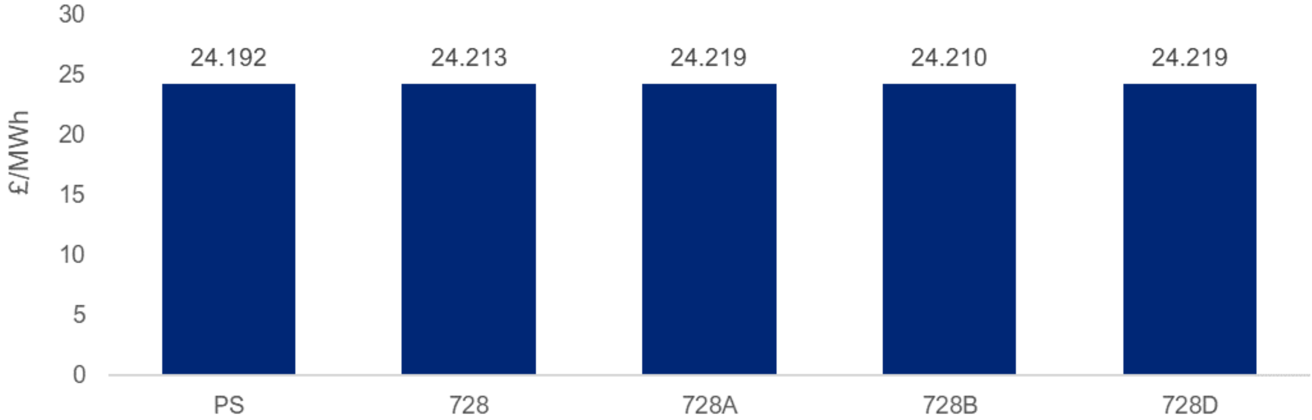


Figure A.41: Simulated wholesale electricity prices (SP, 2026-27, £18/19)

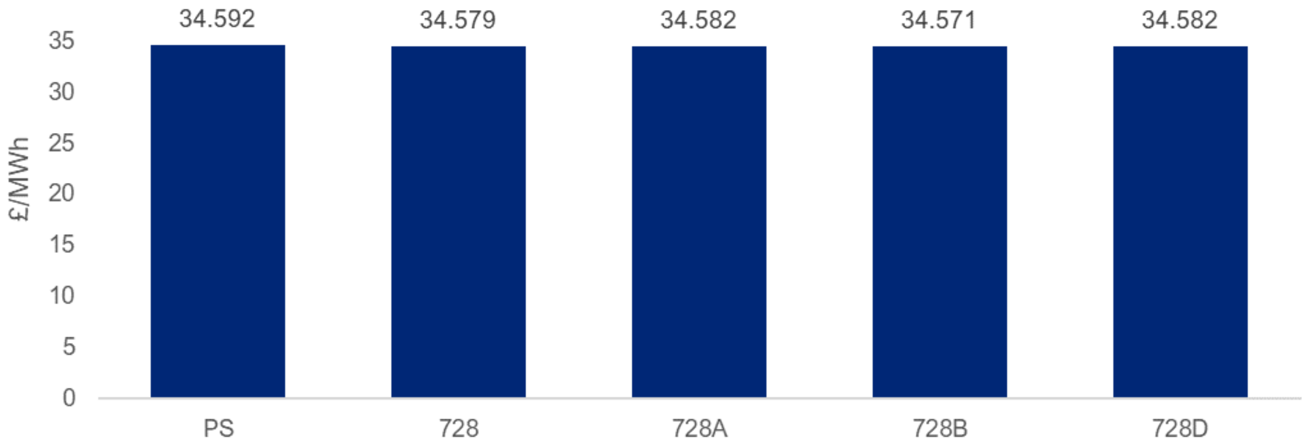
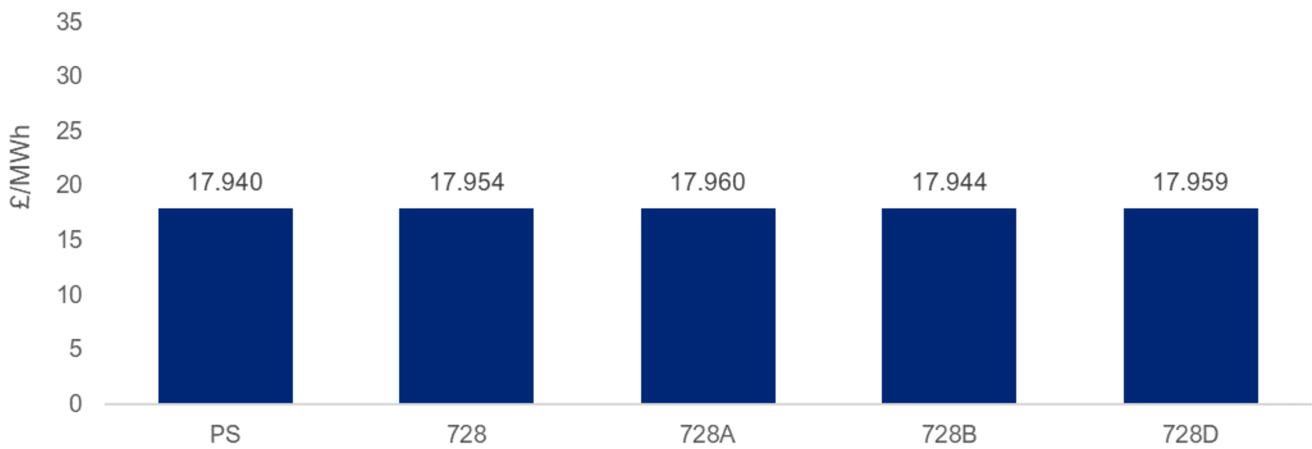


Figure A.42: Simulated wholesale electricity prices (SP, 2030-31, £18/19)



A.2.3. Consumer welfare

Figure A.43: Gas consumer welfare impacts (SP, 2022-2031, NPV, discounted to £18/19)[41]

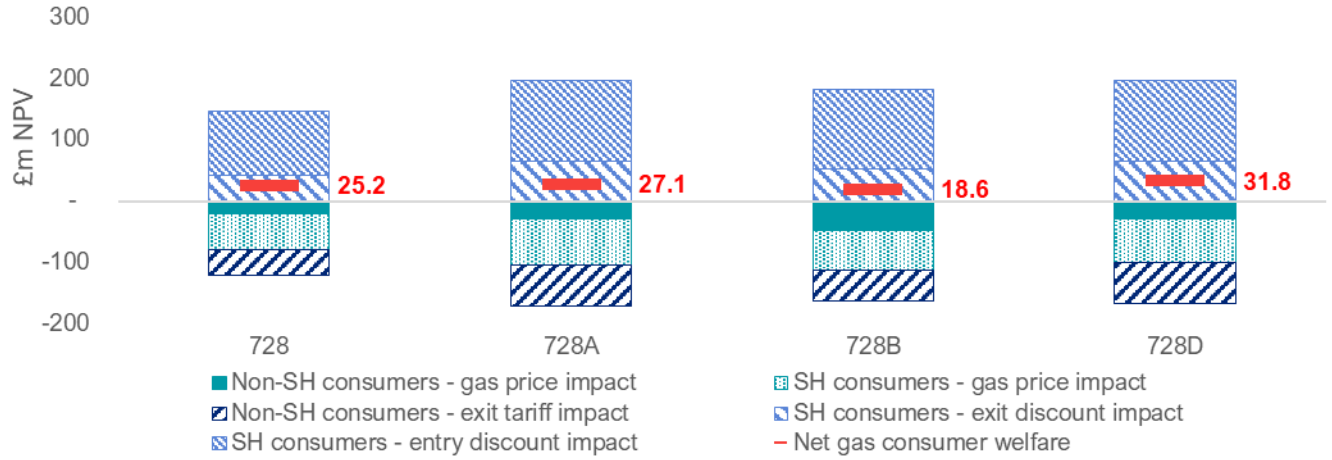
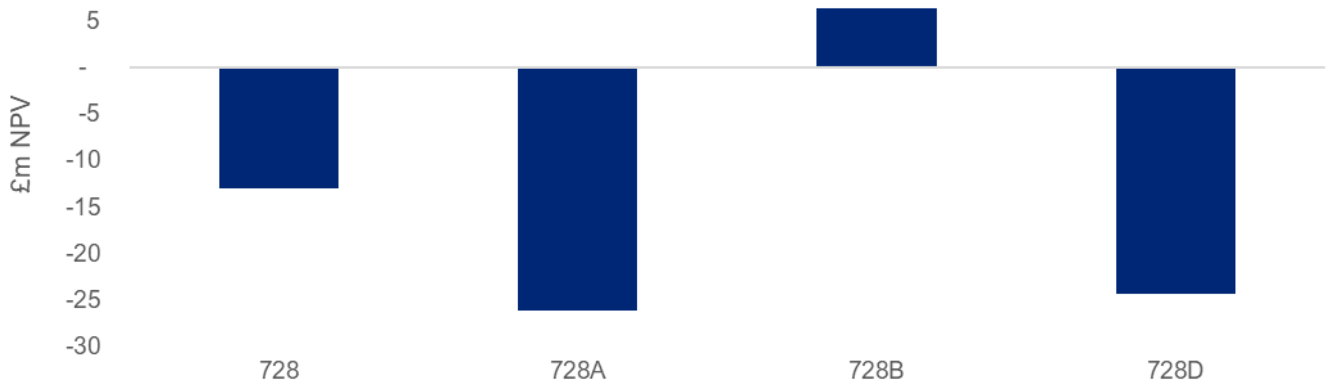
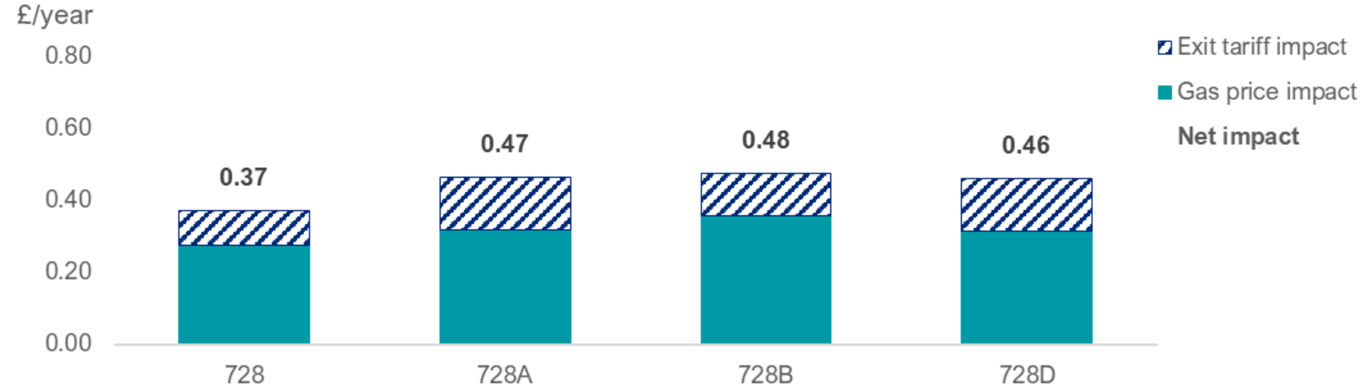


Figure A.44: Electricity market welfare impacts (SP, 2022-2031, NPV, discounted to £18/19)



A.2.4. Bill impacts

Figure A.45: Estimated bill impact for median consumption domestic gas consumers (Central case (CT), 2022-23, £18/19)



[41] NB: While we continue to observe a negative impact on non-SH consumers due to price and tariff impacts under the SP sensitivity, we observe a marginal welfare benefit overall. This is driven by the discount on the entry and exit tariffs received by shorthaul consumers.

Figure A.46: Estimated bill impact for median consumption domestic gas consumers (SP, 2026-27, £18/19)

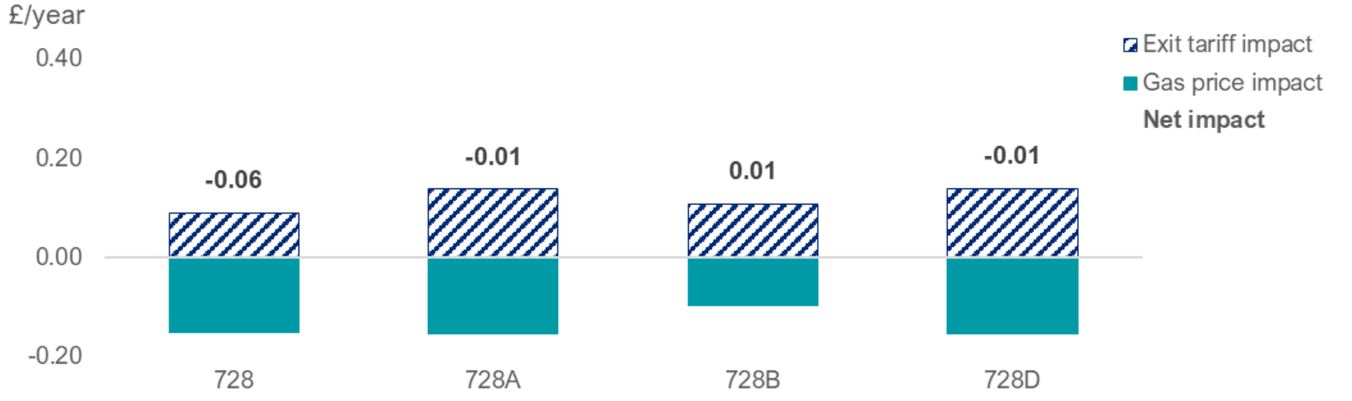


Figure A.47: Estimated bill impact for median consumption domestic gas consumers (SP, 2030-31, £18/19)

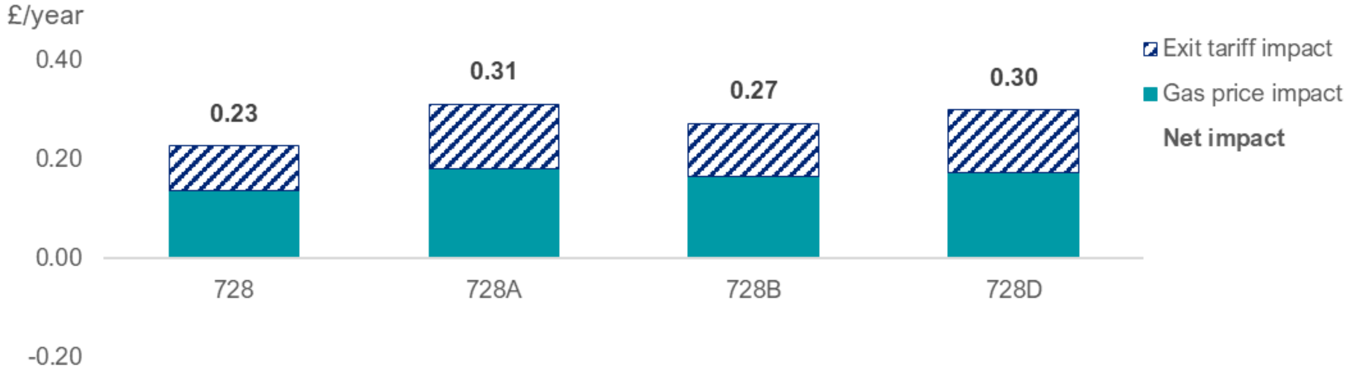


Figure A.48: Estimated bill impact for median vulnerable domestic gas consumers (Central case (CT), 2022-23, £18/19)

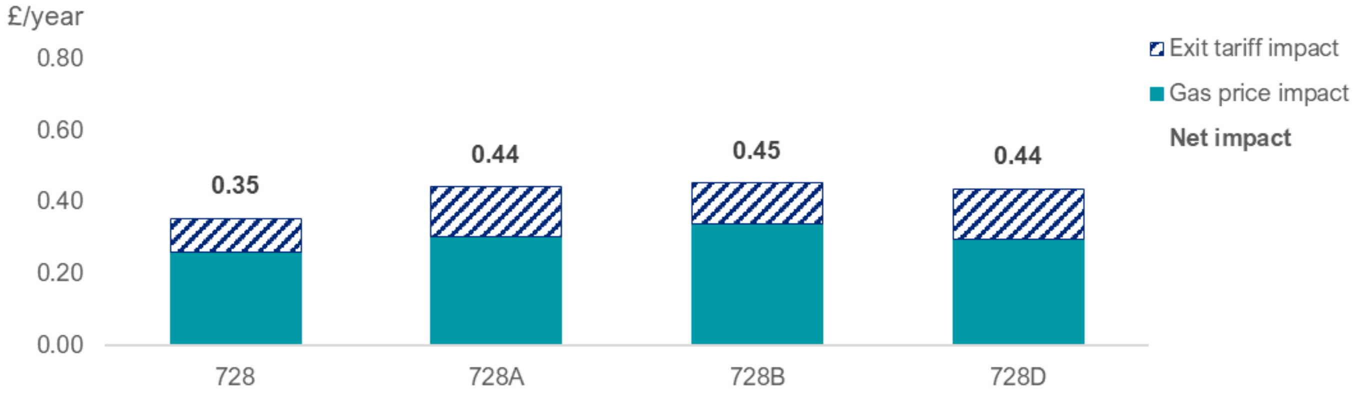


Figure A.49: Estimated bill impact for median vulnerable domestic gas consumers (SP, 2026-27, £18/19)

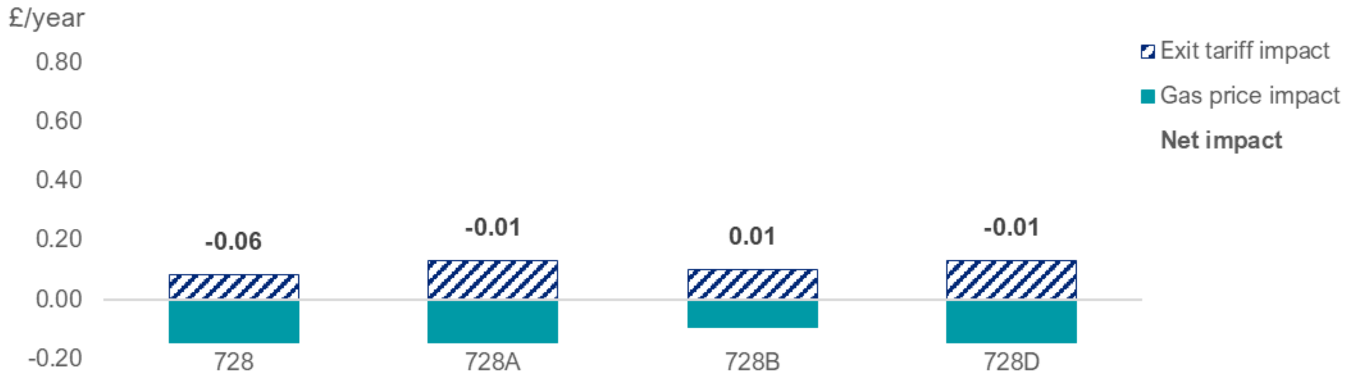


Figure A.50: Estimated bill impact for median vulnerable domestic gas consumers (SP, 2030-31, £18/19)

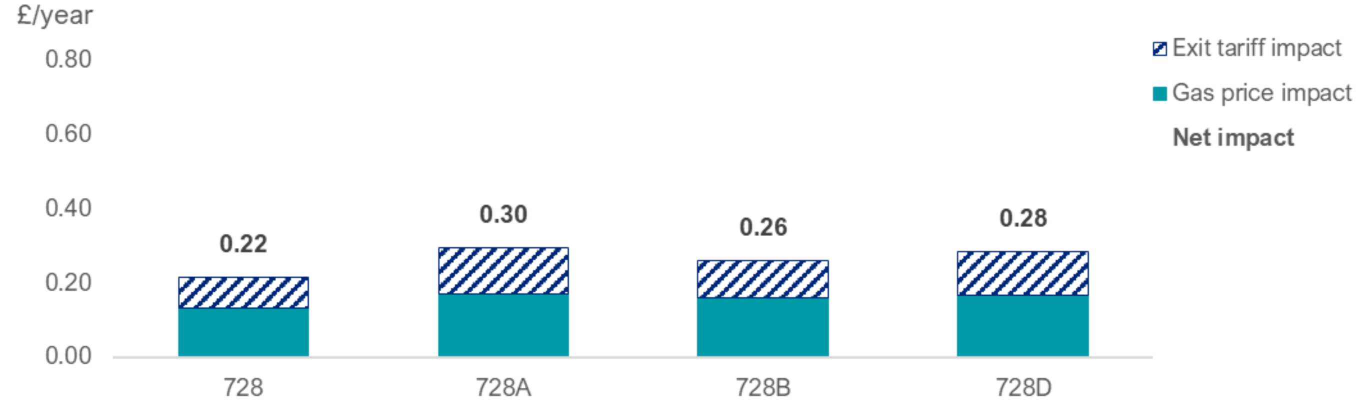


Figure A.51: Estimated bill impact (gas only) for the median non-domestic consumer connected to the LDZ (Central case (CT), 2022-23, £18/19)

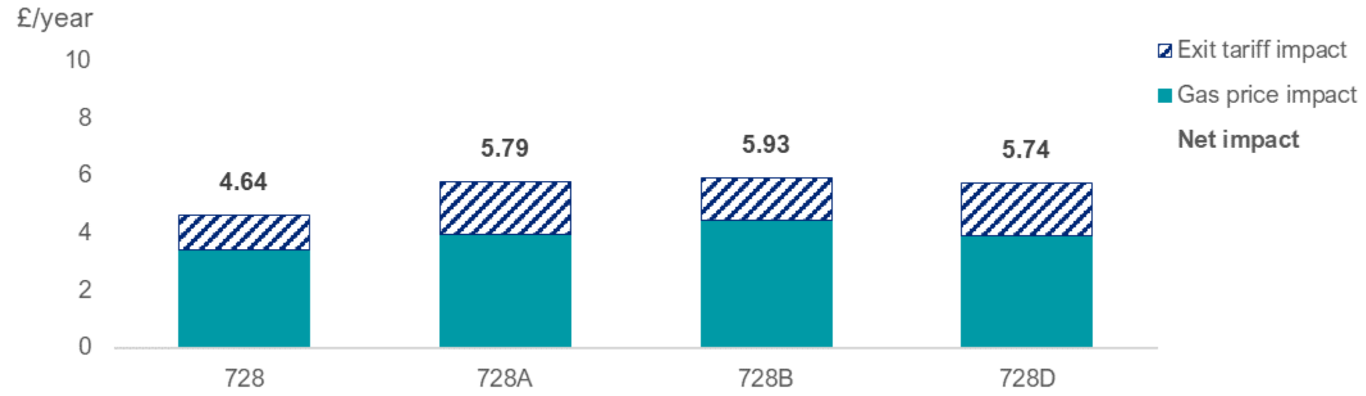


Figure A.52: Estimated bill impact (gas only) for the median non-domestic consumer connected to the LDZ (SP, 2026-27, £18/19)

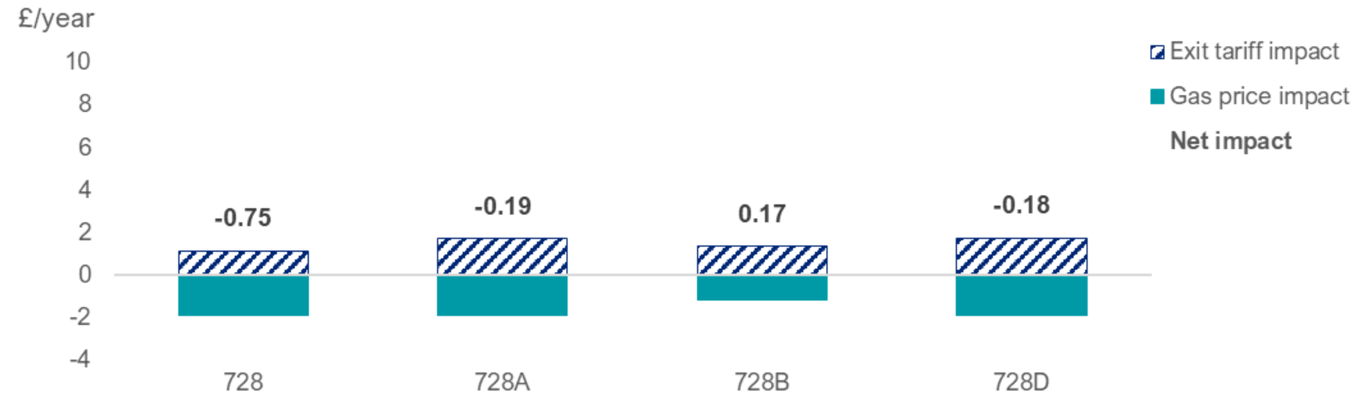


Figure A.53: Estimated bill impact (gas only) for the median non-domestic consumer connected to the LDZ (SP, 2030-31, £18/19)

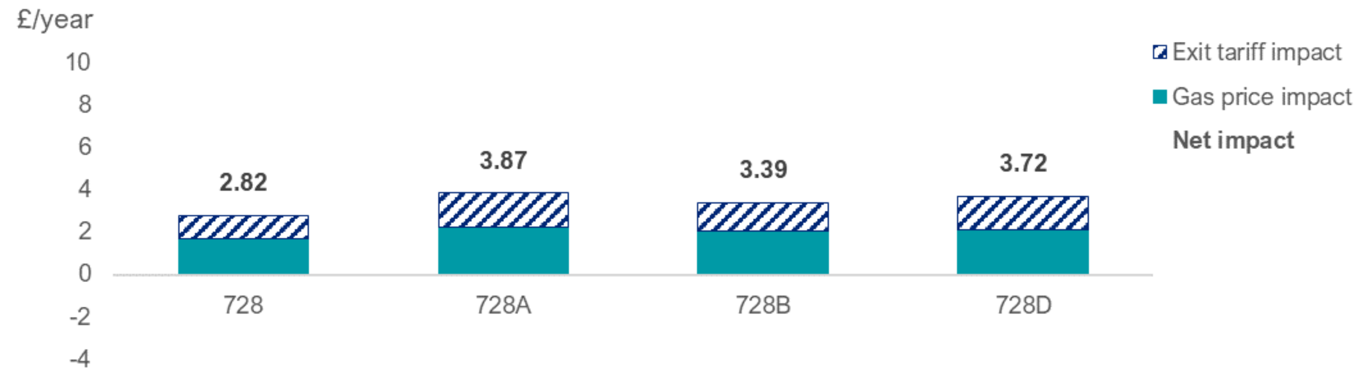


Figure A.54: Estimated bill impact (gas only) for the median non-domestic consumer connected to the NTS, not eligible for shorthaul (Central case (CT)*, 2022-23, £18/19)*

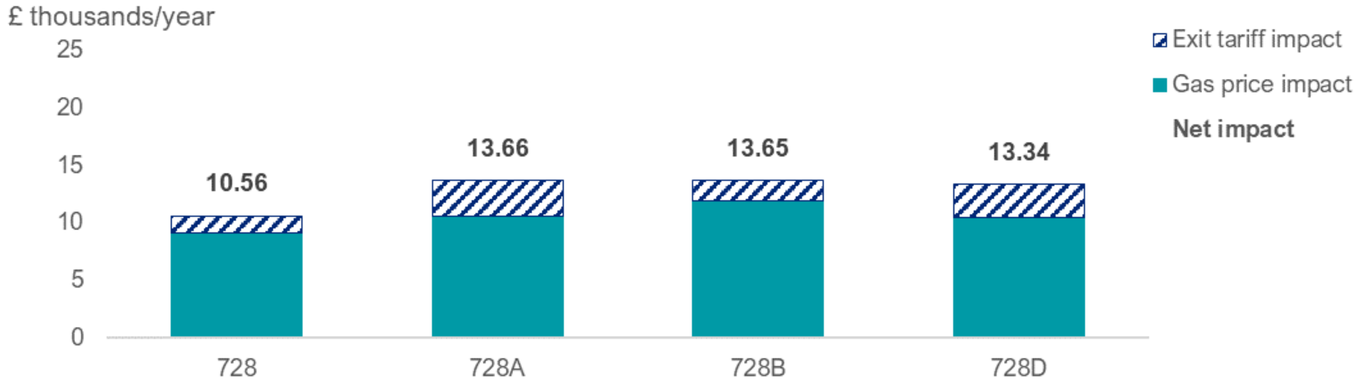


Figure A.55: Estimated bill impact (gas only) for the median non-domestic consumer connected to the NTS, not eligible for shorthaul (SP, 2026-27, £18/19)

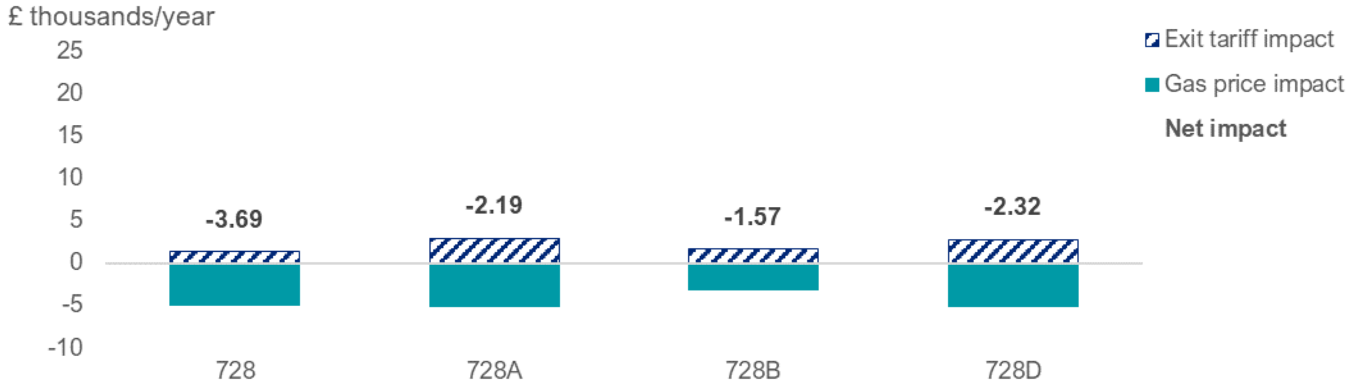


Figure A.56: Estimated bill impact (gas only) for the median non-domestic consumer connected to the NTS, not eligible for shorthaul (SP, 2030-31, £18/19)

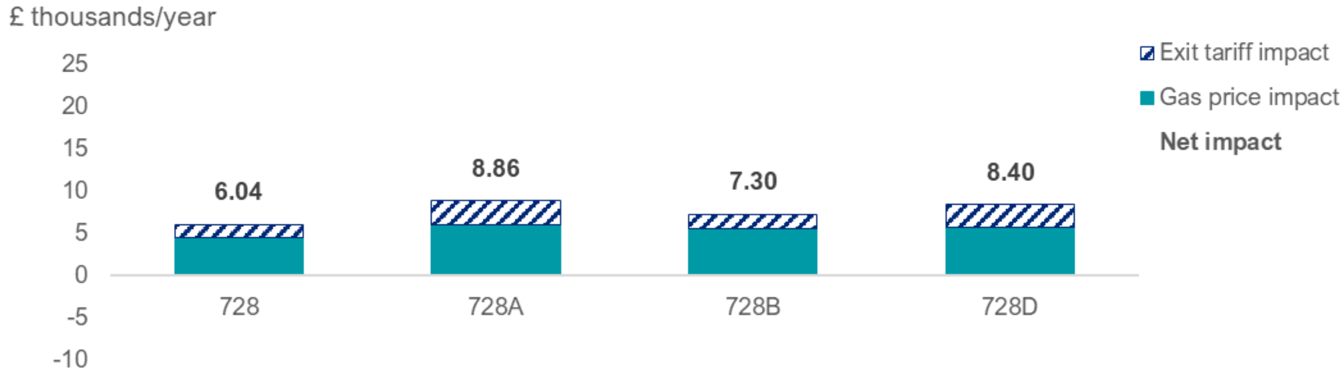


Figure A.57: Estimated bill impact (gas only) for the median non-domestic consumer connected to the NTS, eligible for shorthaul and utilising the shorthaul product for 100% of its bookings/flows (Central case (CT)*, 2022-23, £18/19)*

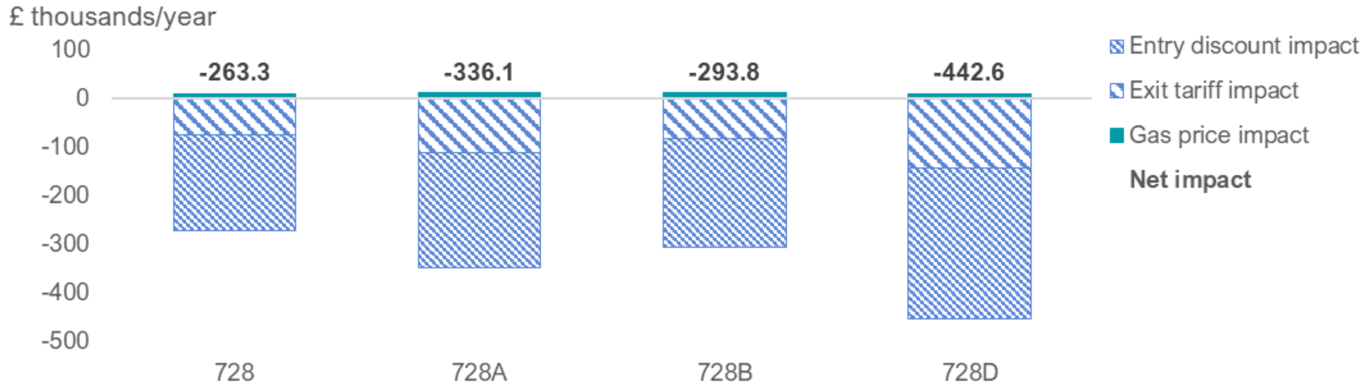


Figure A.58: Estimated bill impact (gas only) for the median non-domestic consumer connected to the NTS, eligible for shorthaul and utilising the shorthaul product for 100% of its bookings/flows (SP, 2026-27, £18/19)

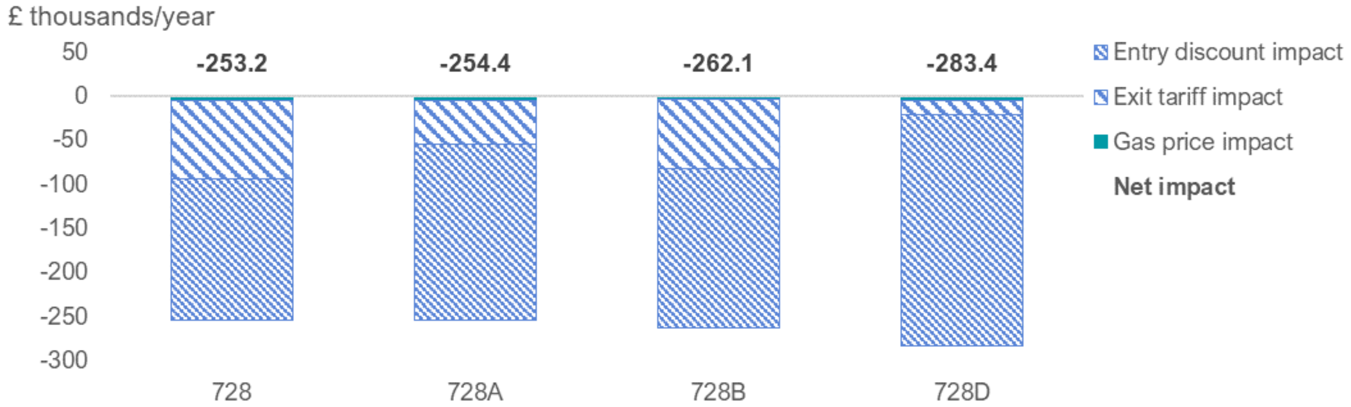


Figure A.59: Estimated bill impact (gas only) for the median non-domestic consumer connected to the NTS, eligible for shorthaul and utilising the shorthaul product for 100% of its bookings/flows (SP, 2030-31, £18/19)

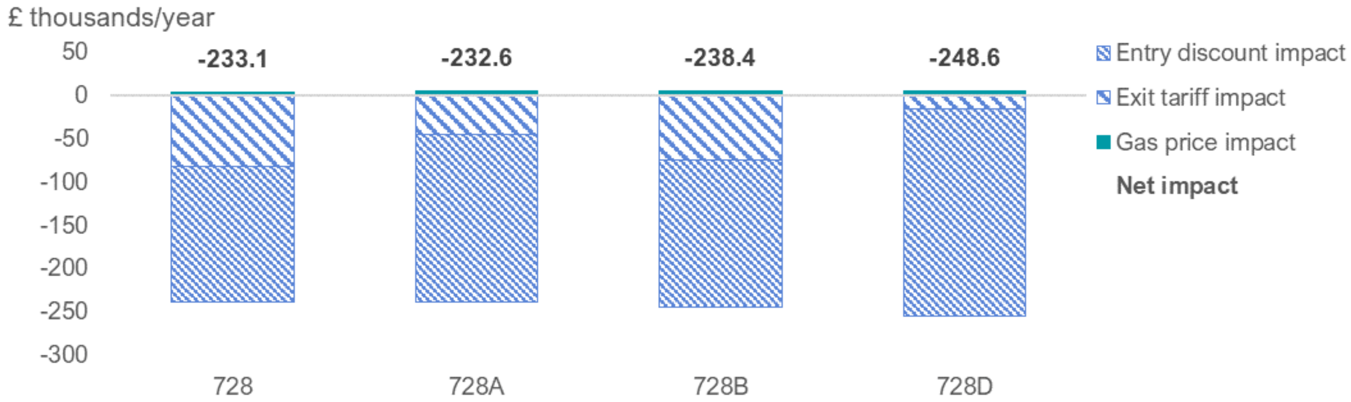


Figure A.60: Estimated bill impact for median consumption domestic electricity consumers (SP, 2030-31 £18/19)

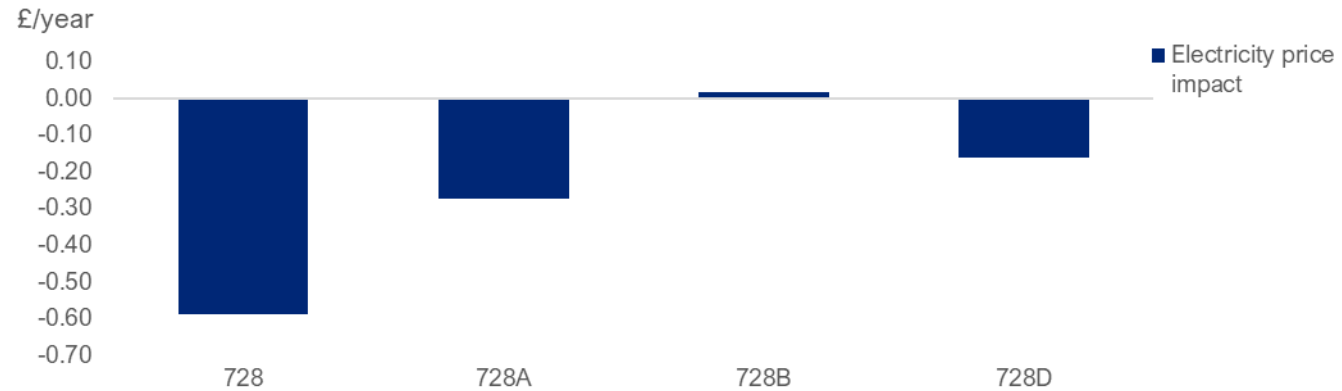


Figure A.61: Estimated bill impact for median vulnerable domestic electricity consumers (SP, 2030-31 £18/19)

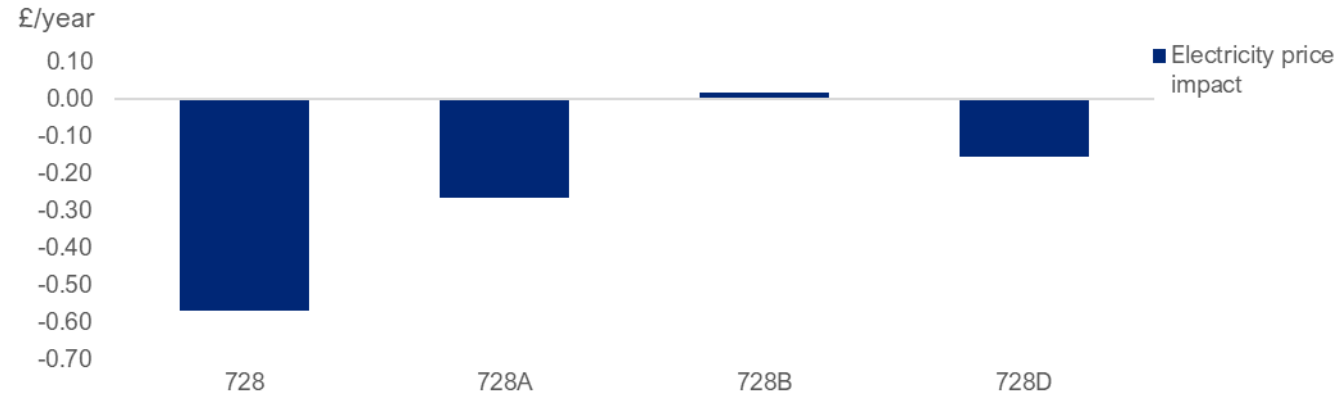
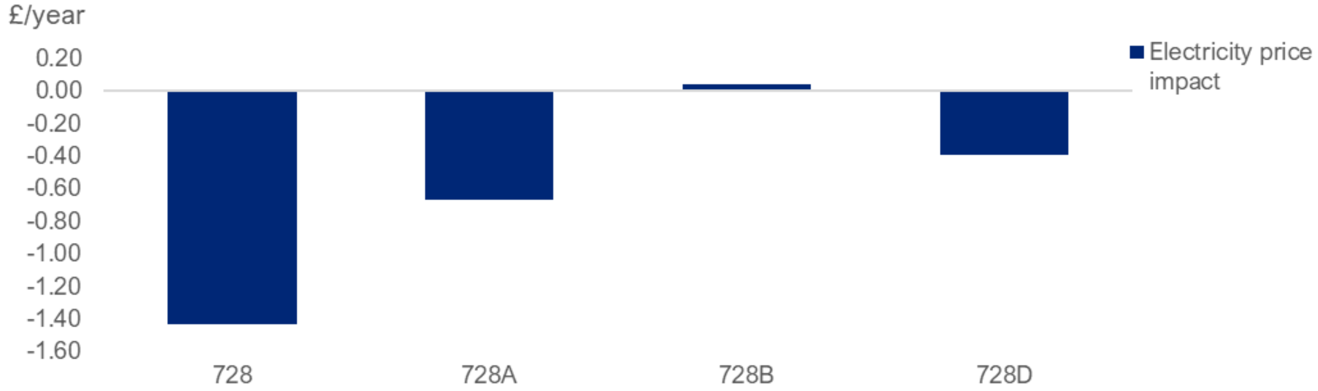


Figure A.62: Estimated bill impact for median consumption non-domestic electricity consumers (SP, 2030-31 £18/19)



A.2.5. Impacts on power stations and carbon emissions

Figure A.63: Impacts on revenues of GB gas-fired power stations (SP, 2022-2031, NPV, discounted to £18/19)

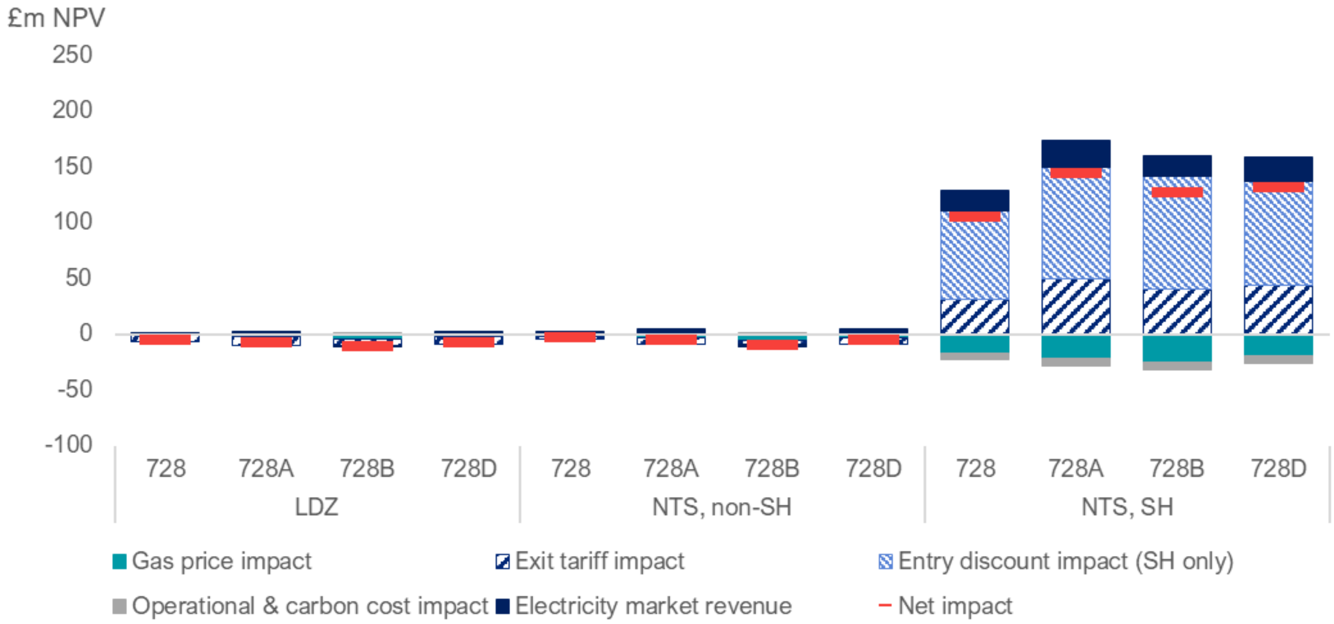
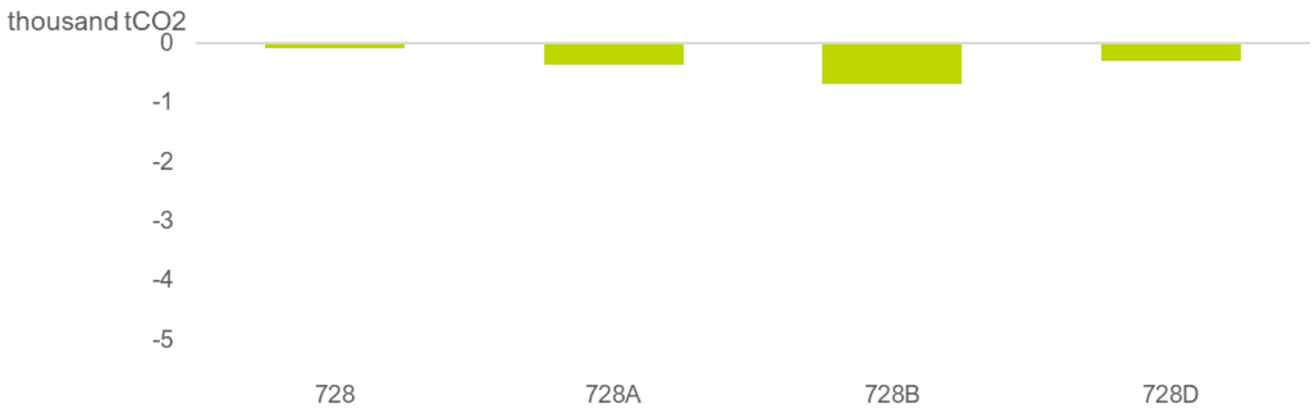


Figure A.64: Impacts on average annual CO2 emissions (SP, 2022-2031)



A.2.6. Impacts on producer revenues

Table A.65: Impacts on total revenues of entry-only points, interconnectors, and gas storage facilities (NPV, 2022-2031, £m 2018/19)

£m NPV	728	728A	728B	728D
Entry-only points[42]				
Beach terminals				
Wholesale gas price impact	64.25	86.36	93.64	84.67
Entry tariff impact (incl. shorthaul tariffs)	-1.15	-1.17	-1.68	-0.79
Net impact	**63.09**	**85.19**	**91.97**	**83.87**
Onshore fields				
Wholesale gas price impact	0.17	0.22	0.31	0.22
Entry tariff impact (incl. shorthaul tariffs)	-0.02	0.00	-0.02	0.01
Net impact	**0.15**	**0.23**	**0.29**	**0.22**
LNG terminals				
Wholesale gas price impact	*No LNG flows over our modelling horizon under this scenario under any of the options, so no impacts.*			
Entry tariff impact (incl. shorthaul tariffs)				
Net impact				
Interconnectors[43]				
Continental bi-directional interconnectors				
Wholesale gas price impacts (both entry and exit)	12.98	16.29	16.06	16.00
Tariff impacts (incl. shorthaul tariffs, both entry and exit)	0.76	1.56	0.74	1.67
Net impact	**13.73**	**17.84**	**16.79**	**17.66**
Moffat				
Wholesale gas price impact	0.49	1.05	0.57	0.96
Exit tariff impact (not eligible for shorthaul tariffs)	-0.51	-1.10	-0.60	-1.02
Net impact	**-0.02**	**-0.05**	**-0.03**	**-0.06**

[42] We estimate net impacts for producers and LNG terminals by pricing flows of entry gas at the prevailing wholesale gas price and subtracting estimated entry tariffs (including any shorthaul entry tariffs).

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 impact on producer surplus. This is a reasonable assumption given that upstream costs are unlikely to be affected by changes in the NTS charging methodology.

[43] We calculate net impacts for interconnectors by multiplying the gas flows over the interconnectors by the price differential between markets (depending on the direction of flow) and netting off the entry or exit tariffs under each option. Given a lack of cost data, we did not attempt to incorporate operational costs into our revenue estimates.

As before, this approach effectively focuses on shipper revenues.

£m NPV	728	728A	728B	728D
Storage points[44]				
Wholesale gas price impacts (both entry and exit)	-1.67	-2.28	-1.80	-2.28
Tariff impacts (both entry and exit)	0.01	0.04	0.02	0.03
Operational cost impacts	0.52	0.83	0.60	0.80
Net impact	**-1.14**	**-1.41**	**-1.18**	**-1.44**

[44] To estimate net impacts for storage facilities, 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.

Appendix B DESCRIPTION OF GAS AND ELECTRICITY MARKET MODELS

The current gas market model covers all existing gas consumption and production regions (for a complete list of production and consumption countries and regions and the covered in the model and its geographical granularity see Table B.1):

- 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);
- Other demand centres are aggregated to the regional level, such as the Middle East or JKT (Japan, South Korea & Taiwan).

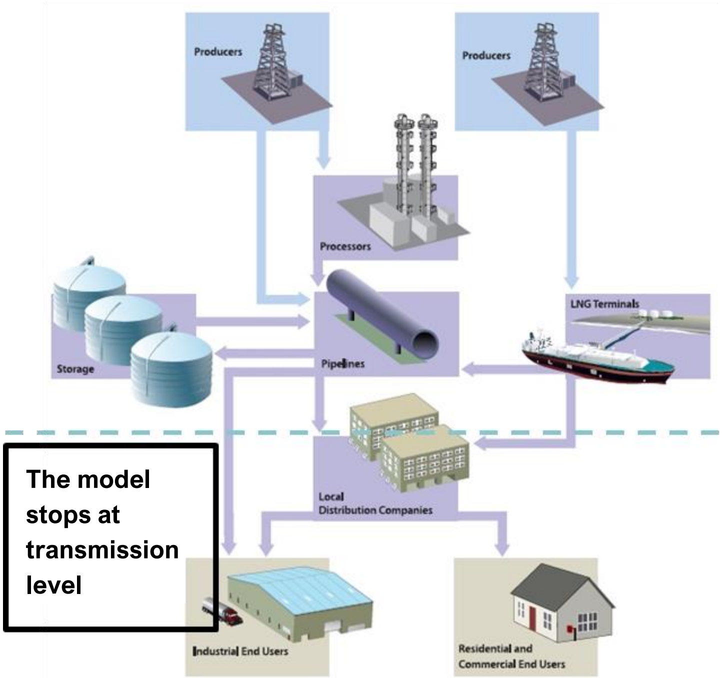
B.1. Time Resolution

- The model solves for **daily** flows and prices; but it can also be setup to solves for **monthly** or **annual** flows and prices.

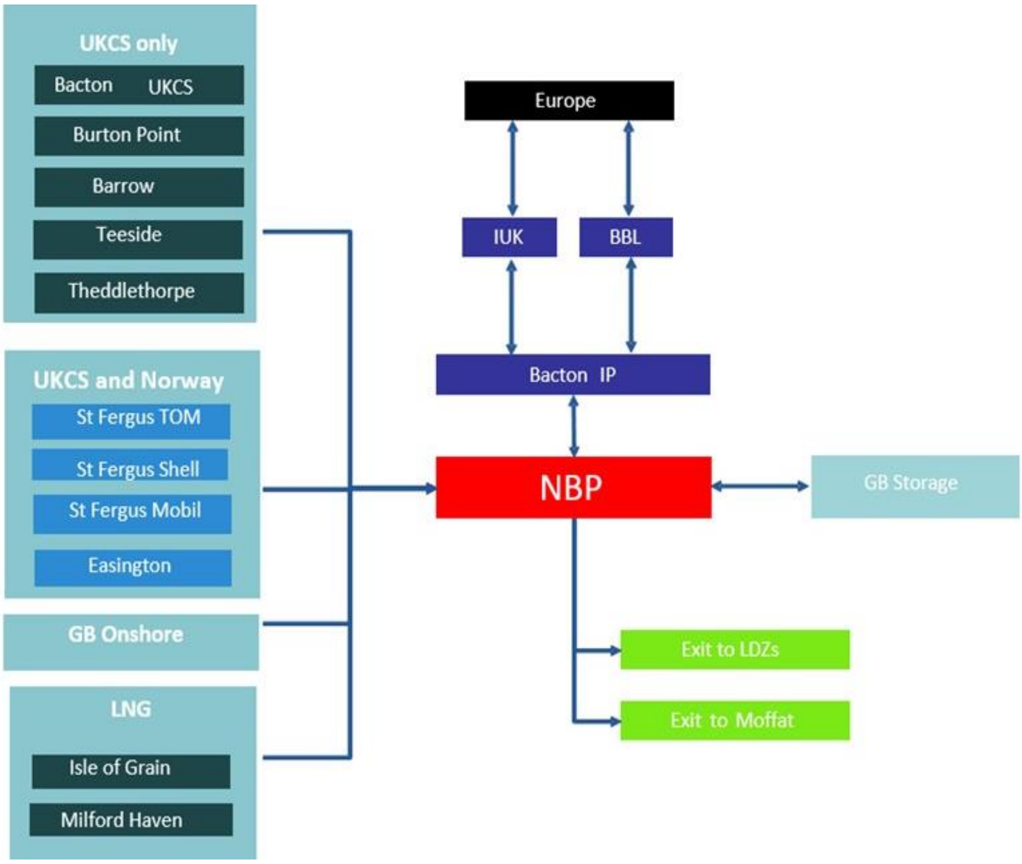
B.2. Gas supply chain

- Covers the entire supply chain down to the transmission level (i.e., distribution level is not considered).
- Represents production, demand, transit routes, LNG facilities, and gas storages.

Figure B.1: Gas Supply Chain in the Model



B.3. UK NTS REPRESENTATION



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.

B.4. EU CROSS-BORDER TRANSMISSION CAPACITIES & TARIFFS

- The model can incorporate all existing cross-border interconnector points (IP), as they are reported by ENTSO-G 2019 Capacity Map[45]; depending on the scope of a specific research project, all the IP points might be aggregated to reduce the size of the optimisation problem.
- For the transmission cost structure, we assume existing tariffs (e.g., annual capacity products).

[45] https://www.entsog.eu/maps#transmission-capacity-map-2019

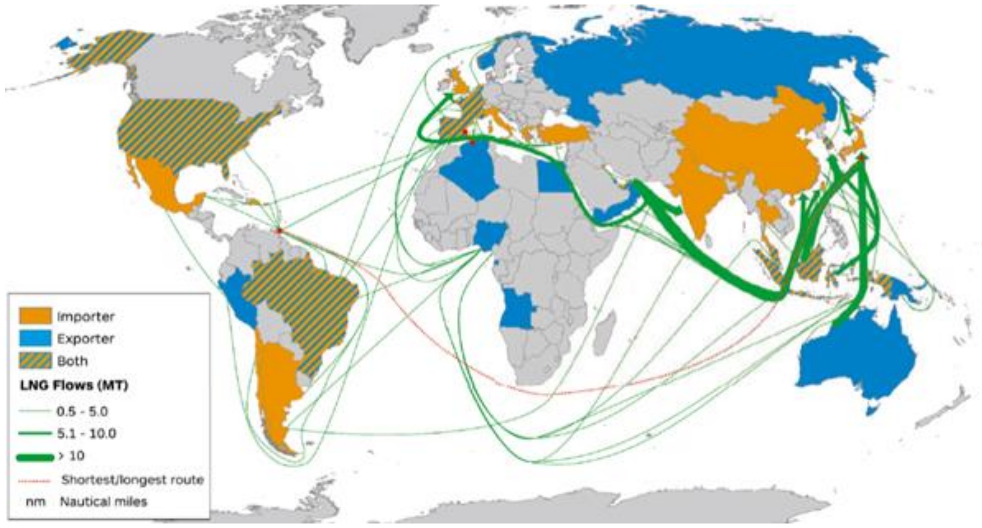
B.5. Storage capacities & costs

- 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 these 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.

B.6. LNG market

- We model every individual LNG regasification terminal in Europe as of 2018 (see Table B.2).
- LNG Shipping routes are 'pre-specified' in the model as a network (nodes-arcs) – see Figure B.2;
- 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.

Figure B.2: LNG markets in the Model



B.7. Price setting and modelling objective

Model objective

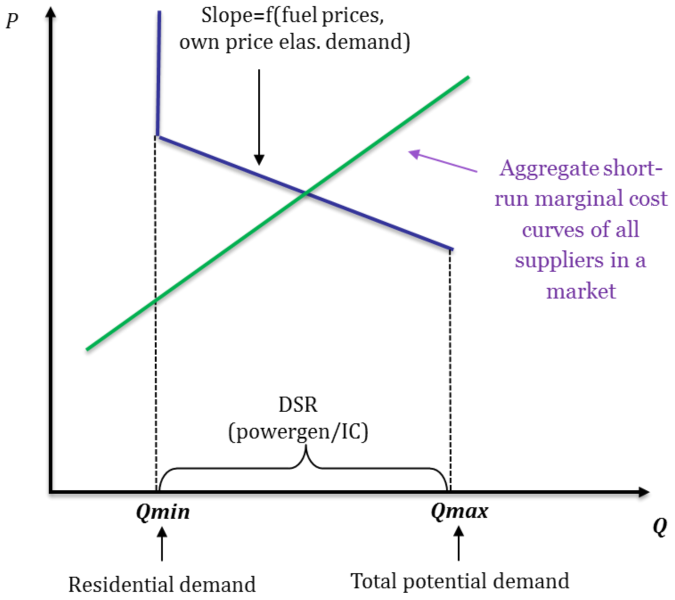
Given assumed marginal costs of gas production, transport and storage, the model objective is to ***maximise social welfare (minimise total cost) while meeting various constraints:***

- Production capacities;
- Transmission (entry/exit) capacities;
- LNG liquefaction & LNG send-out capacities;
- Conventional underground storage;
- LNG storage injection, withdrawal & max working volume capacities;
- And meeting daily *Qmin* demand while not violating *Qmax* demand constraints (Figure B.3).

Demand curves

- Consider short-term demand side response;
- 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 to account for possible inter-fuel competition and evolving market structure in the power generation sector in Europe** (see);
- Slope of the demand curves 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 B.3: 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 at plant level

'copper plate' model, assumes complete market coupling for cross-border trade taking into account NTCs

Models day-ahead energy only as well as operating reserve requirement

Takes into account main techno-economic constraints such as ramping, minimum up/down time

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

UK

Queens House

55-56 Lincoln's Inn Fields

London WC2A 3LJ

T. **+44 (0)20 7269 0210**

E. **info@cepa.co.uk**

www.cepa.co.uk

cepa-ltd @cepaltd

Australia

Level 20, Tower 2 Darling Park

201 Sussex St

Sydney NSW2000

T. **+61 2 9006 1307**

E. **info@cepa.net.au**

www.cepa.net.au