Gas Transmission Charging Review Model

Office of Gas and Electricity Markets

September 2014

FINAL Report

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CONTENTS

IMPORTANT NOTICE

1. INTRODUCTION

1.1. Context

CEPA in association with TPA Solutions (TPA) has been commissioned by Ofgem to develop a tariff and impact assessment model for specific potential changes in the structure of the gas National Transmission System (NTS) charges in Great Britain (GB) to support its ongoing Gas Transmission Charging Review (GTCR).

Ofgem launched the GTCR in June 2013 to look at the structure of the existing gas transmission charging regime and how effective it is in protecting the interests of existing and future consumers.[1] This was in response to stakeholders concerns about the growing level of the "entry commodity charge"[2] and European developments, including European Network Codes which are being developed in order to provide and manage effective and transparent access to the transmission networks across European borders.

Ahead of a future consultation process, Ofgem is considering a range of policy options (described below) as part of the GTCR. These may result in changes to the approach to cost allocation used to calculate the tariffs or reserve prices which apply to all, or only a subset of, NTS Aggregated System Entry Points (ASEPs).[3] The GTCR model is intended to support Ofgem's analysis of the GTCR policy options.

The model described in this report was developed with input from an expert industry working group. We would like to thank the industry group participants for the comments and feedback provided on the model and its inputs during development.

1.2. GTCR policy option overview

The GTCR is considering three policy options:

1. changes to the structure of discounts (multipliers) applied to short-term capacity products under the current charging regime;[4]
2. adjustments to the payable price on long-term capacity to take account of inflation effects; and
3. introduction of a floating tariff regime based on the principles set out in the EU Framework Guidelines on Harmonised Transmission Tariffs (see below) either at all entry points or entry points that interconnect with other transmission networks.

[1] https://www.ofgem.gov.uk/gas/transmission-networks/gas-transmission-charging-review

[2] A charge levied on entry flows (excluding shorthaul and storage flows) in the event of a forecast under-recovery of capacity auction revenue against the TO Entry target allowed revenue. Can be a negative charge in case of allowed revenue over-recovery.

[3] Changes to the exit tariffing regime are not currently being considered as part of the GTCR.

[4] Currently all system Entry capacity auctions are subject to reserve prices. A number of shorter term capacity auction products are sold at discount to longer term capacity products.

As well as a set of policy design and assessment criteria[5], these options have been developed to take account of potential future European legislation and code compliance requirements, in particular, compliance with ACER's EU Framework Guidelines for Harmonised Transmission Tariffs[6] and the expected future ENTSO-G network code for gas transmission tariffs.[7]

The Tariffs Network Code (TAR NC) and the Capacity Allocation Network Code (CAM NC) will, respectively, change the charging and capacity allocation arrangements at the transmission interconnection points, and may also affect the principles under which domestic charging methodologies must be drawn up. One key change at the interconnection points, for example, is that the Transportation Owner (TO) entry commodity charge may no longer be permitted as the residual mechanism through which NGG[8] recovers allowed revenues.

We discuss the underlying rationale and approach to modelling of each of the GTCR policy options later in the report.

1.3. ACER Framework Guidelines

The EU Framework Guidelines for Harmonised Transmission Tariffs (TAR FG), upon which the final TAR NC will be based, lays down a series of requirements for harmonising gas transmission tariff structures across the EU. In developing the functionality of the GTCR model, the TAR FG has been used as the principle guide for the modelling as final drafting of the TAR NC is still uncertain and subject to future stakeholder consultation.[9]

Some of the TAR FG requirements, such as the underlying approach to cost allocation, will apply to all transmission services offered at all entry and exit points on the gas transmission systems operated by a gas Transmission System Operator (TSO). In a GB context, this means that the final TAR NC will have effect on all entry and exit points on the NTS.

There are, however, also a set of provisions that apply specially to interconnection points under the scope of the CAM NC (referred to as CAM points). These include provisions related to new and incremental capacity and provisions applying to the determination of reserve prices for capacity auctions that will apply at EU CAM points (the latter being relevant to the GTCR options and model design).

As described in Section 2, the GTCR model has been designed to allow consistent or differential tariff regimes to apply at CAM and Non-CAM NTS points. This is referred to as an

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[5] Including economic efficiency (in both the short run and long run), impact on cross-border trade, reflection on developments in the transportation business and impact on security of supply.

[6] ACER (2013): 'Framework Guidelines on rules regarding harmonised transmission tariff structures for gas', November 2013

[7] The initial draft of the Network Code on Tariffs was published in May 2014. The draft and its supporting consultation is published on ENTSO-G's website.

[8] National Grid Gas.

[9] For the avoidance of any doubt, however, none of the model options set out in this report are intended to provide either Ofgem or CEPA/TPA's interpretation of the TAR FG or current draft of the TAR NC. The model has been developed to accommodate a range of different approaches to policy options – e.g. floating tariff regimes – some of which may or may not be consistent with the TAR FG and final TAR NC.

"asymmetric" tariffing regime within the GTCR model and allows the model user to compare potential outcomes of asymmetric tariffing principles.

For ease of reference, for the remainder of this document, the following definitions are applied in describing NTS ASEPs:

- CAM points – are NTS interconnection entry points (Bacton IP ASEP, Moffat IP ASEP) subject to full provisions of CAM NC and TAR NC;
- Non-CAM points – are domestic NTS entry points (all entry points, apart from Bacton and Moffatt IP ASEPs), subject to some of the provisions of TAR NC.

1.4. Scope of the model

The model CEPA and TPA has developed provides a tool for Ofgem to undertake quantitative analysis of the policy options that are being considered through the GTCR. The model and its outputs, however, will only form a part of a wide range of evidence and analysis expected to be used to reach any decision on the policy options.

Furthermore, the modelling is necessarily dependent on a series of assumptions, including those on future availability of gas supply sources to the UK, wholesale National Balancing Point (NBP) gas prices, the price responsiveness of demand for NTS capacity and GTCR policy design, which drive the outputs the model produces.

As such, whilst the model is valuable in enabling a number of hypotheses to be tested, its results will need to be placed in the context of a much wider qualitative and quantitative assessment, as part of a consultation process in which it is used to support conclusions rather than its outputs being seen as definitive. In using the model, Ofgem should expect to carefully consider that the assumptions used are consistent and appropriate to the policy option analysis undertaken in the model.

In Section 3 of the report we discuss and highlight some of the key methodological assumptions in the model, including potential refinements to the GTCR model that Ofgem could consider as part of its future development.

1.5. Report structure

The rest of this report is structured as follows:

- Section 2 outlines the modelling framework used to quantitatively analyse the GTCR policy options.
- Section 3 describes key stages in the model calculations, including gas flow and NTS capacity booking modelling.
- Section 4 lists the key assumptions and sources of underlying data used within the GTCR model.

- Section 5 presents the outputs produced by the GTCR model in forming the impact assessment of a modelled policy option.

A series of annexes provide supporting material:

- Annex A describes the principles of price responsiveness of demand for NTS capacity applied within the GTCR model.
- Annex B describes the different capacity charge regime options which can be selected and modelled in the GTCR model.
- Annex C provides a write-up of aspects of the approach used to model cross-border interconnector flows.
- Annex D provides a similar write-up to Annex C but for modelling of Long Range Storage (LRS).
- Annex E describe the assumptions and methodology used to determine NTS user booking strategies for individual ASEPS.

2. MODELLING FRAMEWORK AND POLICY OPTIONS

2.1. Overview

The modelling framework used for the GTCR policy options is a combination of three modelling components which draw on common input data and modelling outputs across each of the three model components:

- The first model component calculates NTS capacity and (where appropriate) commodity entry tariffs under the modelled policy option for each ASEP, for each financial year (2014/15 to 2028/29)[10] and each capacity product.
- The second model component calculates flows (market dispatch) by NTS ASEP for each day in the financial year to determine the requirement (demand) for NTS capacity on each day in the financial year.
- The third model component calculates network user booking strategies (by ASEP supply source) to determine what form of capacity (short term or long term) is expected to be used to meet a capacity requirement at each ASEP.

Underpinning components two and three are assumptions of the price responsiveness of demand for NTS capacity (as described in Annex A) which influences the approach taken for modelling ASEP flows and capacity bookings.

The three model components are combined to produce an impact assessment of the modelled policy options. The impact assessment uses both the current structure of network user NTS bookings and modelled dynamic changes in network user behaviour[11] to analyse the impacts of the GTCR policy options.

The outputs produced by the model include:

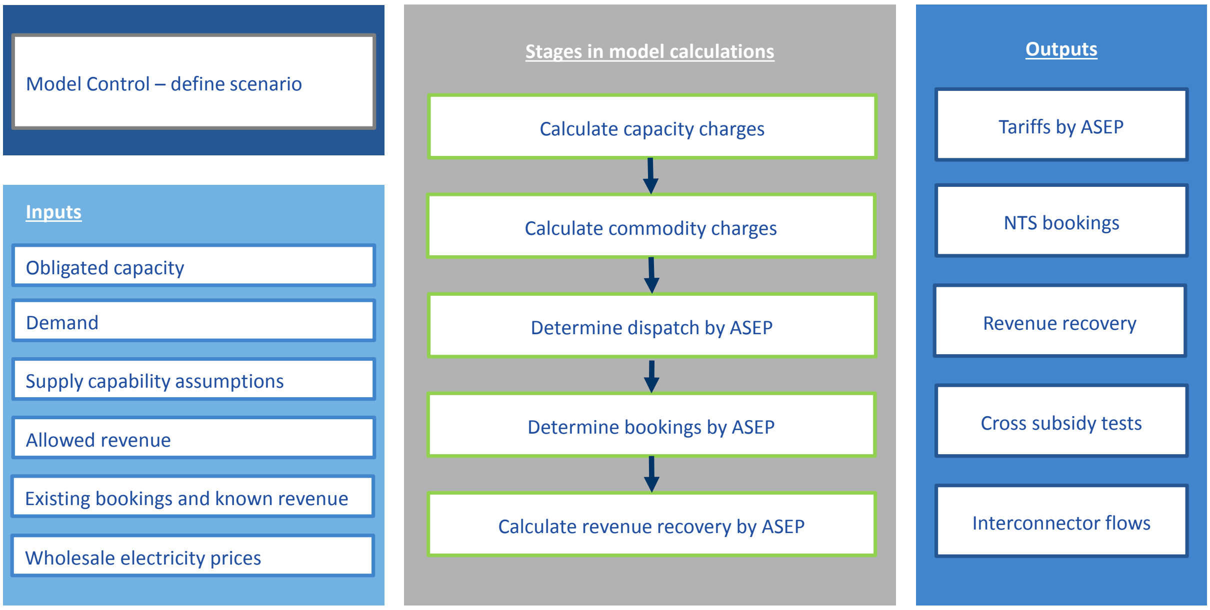
- The absolute level and changes (relative to the current entry charging methodology) in capacity and commodity tariffs by ASEP.
- Analysis of charging incidence (revenue recovery) by ASEP and network user group again both in absolute terms and relative to a base case.
- Modelled entry (e.g. cross-border) flows in response to changes in the structure of NTS entry prices.
- A simplified cost subsidy test of tariffs using Long Run Marginal Costs (LRMCs) from the Transportation model as cost drivers.

[10] Years in the model represent financial year ending (e.g. 2015 represents financial year 2014/15).

[11] As described later in the report, the model calculates a booking strategy for different supply sources by entry point In response to changes in ASEP entry tariffs (the price responsiveness of demand for NTS capacity) and the changing structure of supply to the GB wholesale gas market.

An overview of the modelling framework is provided in Figure 2.1 below, illustrating inputs, calculations and model outputs.

Figure 2.1: GTCR model overview diagram



Source: CEPA and TPA

In the subsections which follow, we provide an overview of the GTCR model control sheets (which drive the model calculations) and the different policy options and modelling choices that can be selected within the model. The modelling approach to a number of the key stages in the model calculations are described later in the report.

2.2. Tariff modelling

The GTCR model has been developed to calculate tariffs and analyse the impacts of three tariff reform options and incorporates:

A. The functionality to change the structure of discounts that are applied to short-term NTS entry capacity products (referred to as multipliers within the GTCR model). The model has been developed to allow the model user to design a multiplier scenario for each financial year in the model.

B. The functionality to change the payable price of existing long-term capacity bookings (QSEC bookings) to account for inflation.[12] This involves taking the strike prices of existing NTS entry QSEC contracts and indexing their strike prices to the applicable financial year in the GTCR modelling.[13]

C. The functionality to model a "floating tariff regime" across all or only a subset of the entry points on the NTS. As discussed below, various options for how the floating tariff

[12] The model has been developed to index existing contract prices consistent with RPI inflation.
[13] As discussed below, there are various options for how the inflation index may be calculated.

regime could be structured are included in the model which use as an input the reserve prices and LRMCs from the Transportation model.

The model start date is the financial year 2014/15 and the model user can also select the modelled policy scenario to start from a particular year in the model (e.g. 2017/18 the date from which the TAC NC is expected to come into effect[14]).

2.2.1. Option A - Multipliers

NTS entry capacity is currently sold through a series of auctions spanning a range of time periods; from quarterly blocks up to seventeen years ahead, right down to within day sales. All Entry capacity auctions are subject to reserve prices, determined by NGG's NTS Transportation Model.

Under the present NGG charging methodology, some capacity products are offered at discounted reserve prices. Specifically, daily reserve prices are calculated by applying the following discounts to the Monthly System Entry Capacity (MSEC) capacity prices: Day Ahead Daily System Entry Capacity (DADSEC) 33.3%, Within Day Daily System Entry Capacity (WDDSEC) 100%, and Daily Interruptible System Entry Capacity (DISEC) 100%.

The model user can input the multipliers that are applied to the reserve prices for each capacity product for each financial year. The parameterised multiplier value for each capacity product (QSEC, MSEC, DADSEC, WWDSEC and DISEC)[15] has no restrictions on the values that can be input by the model user for each capacity product.[16]

2.2.2. Option B – Inflation adjustment to existing contracts

Modelling of the inflation adjustment to existing QSEC bookings has been undertaken outside of the GTCR model as it requires knowledge of strike prices of those existing bookings bought in previous QSEC auctions (which are confidential).

The outputs from three options for inflation adjusting existing QSEC prices are included in the GTCR model based on off-model calculations:

- no inflation adjustment – this is a continuation of the current fixed price regime that applies under the existing tariff methodology (existing bookings retain the prices set as part of previous auction rounds);
- full inflation adjustment – QSEC prices are indexed from the financial year quarter in which the contract started to the quarter of the financial year in which the capacity booking can be used – i.e. applied to existing bookings;

[14] As the GTCR model is based on financial years and we understand that the TAR NC comes into effect in the gas year 2017/18 (starting October 2017) the model makes the simplifying assumption that any policy scenario would apply from 1 April 2017.

[15] We have not covered the annual product at CAM points on the assumption that we expect network users to favour QSEC as a long term product.

[16] Note that the TAR FGs has limits on the values for multipliers.

- indexation from 2017/18 – QSEC prices are indexed from the start of 2017/18 to the quarter of the financial year in which the capacity booking can be used – this means the same inflation index is applied to all existing QSEC contracts.

The Retail Price Index (RPI) has been used as the measure of inflation in the indexation calculations and the source of historical index values (by financial year quarter) is from the Office for National Statistics (ONS).

A three per cent annual RPI assumption has been used for inflating contract prices in all future years from the start of the model.

2.2.3. Option C – Floating tariff

The TAR FGs requires, among other things, that at the interconnection points any over- or under-recovery of revenue will have to be recovered through capacity charges only, and that commodity charges should only be used to recover those costs which are associated with flows (e.g. shrinkage costs).

Specifically, any over- or under-recovery of revenue at these interconnection points is to be recouped through an adjustment to the capacity charges in later years, meaning that the capacity charges are "floating".[17] The regime currently in place for NTS Exit points follows the principles of floating tariffs in seeking to recover target revenue.

There are a number of different approaches/methodologies which Ofgem could consider in designing a floating entry tariff regime that could apply to all ASEPs or only a subset of NTS entry points (e.g. CAM points) in GB. The GTCR model allows the user to select a methodology based upon combinations of the following policy choices:

- a floating adjustment could be applied to the underlying LRMCs (KMs) used currently to derive reserve prices (which would mirror the secondary adjustment to recover allowed revenue applied at exit) or to the reserve prices (p/KWh/day) from the underlying cost allocation methodology;
- the size of the floating adjustment applied to recover target allowed revenue could be based on different measures of capacity (e.g. forecast peak capacity (peak day forecast capacity as used in the Transportation model or NGG's Ten Year Statement), obligated capacity or forecast capacity bookings;
- in *theory* a floating tariff could be calculated pre or post application of multipliers, with the approach adopted impacting on whether a modelled floating tariff regime can be expected to recover target entry revenue at the ASEPs affected by the secondary adjustment to reserve prices;

[17] Under the current regime, the *total* entry charges (capacity *plus* commodity) are effectively only "semi-fixed" at an ASEP level as the size of the commodity charge is variable.

- the floating tariff adjustment (p/kWh/day) could be assumed to apply only to future bookings or all bookings (i.e. new QSEC, short term product bookings and existing QSEC bookings) in seeking to target recovery of entry allowed revenue from capacity rather than commodity (flow based) charges.

Annex B describes the different capacity tariff options which can be modelled in the GTCR model in more detail. In total ten floating options (reflecting the combinations of the choices outlined above) are included in the model, in addition to a base case option that reflects the current methodology. There are, therefore, eleven capacity charging options in the model.

Note certain combinations of these policy choices may or may not be TAR FG and TAR NC compliant. The functionality to model certain options has been included to test the impact of different policy assumptions for illustrative purposes only.

2.2.4. Asymmetric regimes

The floating tariff functionality in the model also allows the model user to select a tariffing regime which applies to CAM and non-CAM points. This allows a different ("asymmetric") tariff regime to be applied to GB CAM points compared to the rest of the NTS entry points, should this be deemed appropriate.

The model user can also select an asymmetric regime for gas storage sites which removes floating tariff adjustments from the capacity charges that apply to storage users in a scenario where a floating tariff is applied to all NTS ASEPs[18]. If this option is selected by the model user, the storage bookings are excluded from the calculations of the size of required floating tariff adjustment to recover target revenue.[19]

[18] Under the current NTS entry charging methodology Storage users do not pay the TO entry commodity charge and this policy remains unchanged in the model. Similarly the policy of not paying the SO commodity charge remains unchanged in the model.

[19] The only exception to this is bookings at Rough which form part of Easington ASEP bookings. A consequence of this is that the floating tariff adjustments in the modelling – where an asymmetric storage regime is selected – is slightly higher than may be required in practice.

2.3. Control sheets

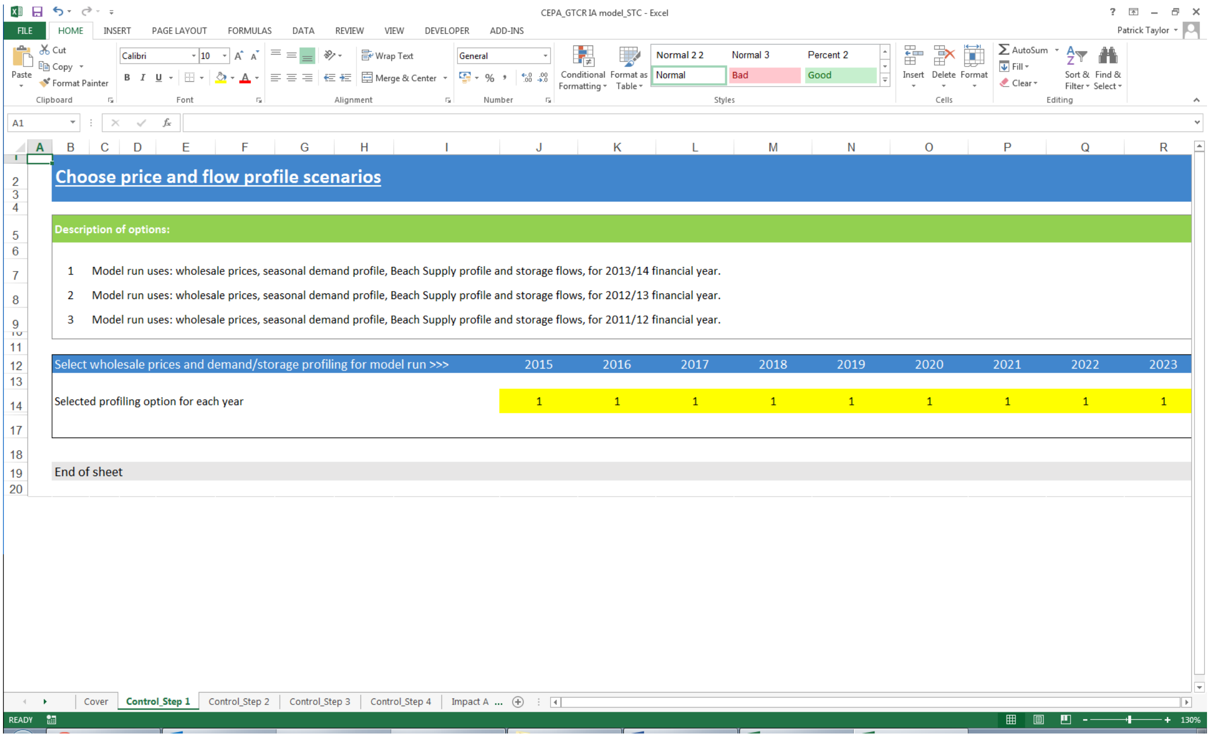
There are four control sheets in the GTCR which drive the model calculations. Each of these are described in the subsections below.

2.3.1. Control sheet 1

Control Sheet 1 allows the model user to define wholesale price and other seasonal demand and storage assumptions used for the model scenario runs.

The model user has the option to select a wholesale price index, seasonal demand *profile* index and beach supply *profile* index from three historical financial years of data (2013/14, 2012/13 and 2011/12).

Figure 2.2: Control Sheet 1



Source: CEPA and TPA

The underlying data and assumptions used in this control sheet are described in more detail later in the report.

2.3.2. Control sheet 2

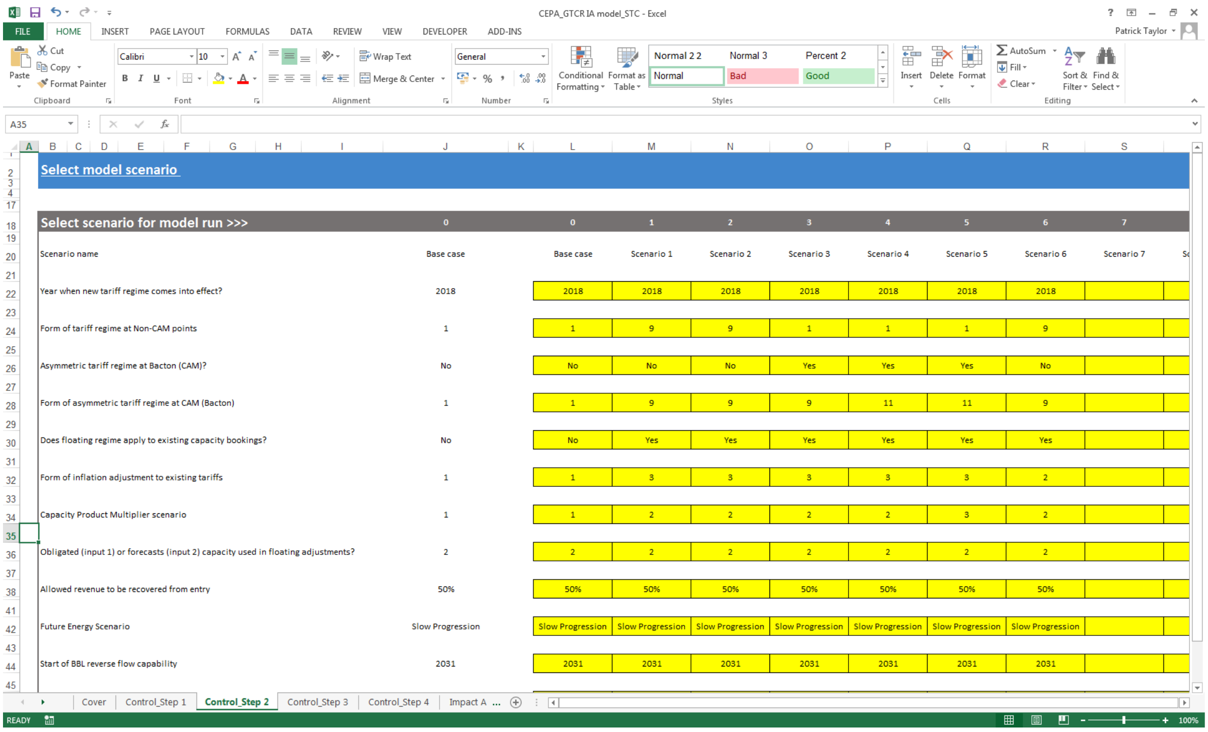
Control Sheet 2 allows the model user to define a set of policy options and model run assumptions. This includes:

- the year when the new tariff regime comes into effect in the model (e.g. 2017/18 to align with the TAR NC);

- form of tariff regime at CAM and Non-CAM NTS points (including the option of asymmetric floating regime for storage users); and
- key flow (dispatch) modelling assumptions – including the treatment of the interconnector assumptions and long term supply and demand assumptions (see discussion in next section of report).

The model user can set up a series of scenarios in the yellow input cells and then can select a scenario for the model run.

Figure 2.3: Control Sheet 2



Select model scenario

Select scenario for model run >>>	0	0	1	2	3	4	5	6	7
Scenario name	Base case	Base case	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7
Year when new tariff regime comes into effect?	2018	2018	2018	2018	2018	2018	2018	2018	
Form of tariff regime at Non-CAM points	1	1	9	9	1	1	1	9	
Asymmetric tariff regime at Bacton (CAM)?	No	No	No	No	Yes	Yes	Yes	No	
Form of asymmetric tariff regime at CAM (Bacton)	1	1	9	9	9	11	11	9	
Does floating regime apply to existing capacity bookings?	No	No	Yes	Yes	Yes	Yes	Yes	Yes	
Form of inflation adjustment to existing tariffs	1	1	3	3	3	3	3	2	
Capacity Product Multiplier scenario	1	1	2	2	2	2	3	2	
Obligated (input 1) or forecasts (input 2) capacity used in floating adjustments?	2	2	2	2	2	2	2	2	
Allowed revenue to be recovered from entry	50%	50%	50%	50%	50%	50%	50%	50%	
Future Energy Scenario	Slow Progression	Slow Progression	Slow Progression	Slow Progression	Slow Progression	Slow Progression	Slow Progression	Slow Progression	
Start of BBL reverse flow capability	2031	2031	2031	2031	2031	2031	2031	2031	

Source: CEPA and TPA

2.3.3. Control sheet 3

Control Sheet 3 allows the model user to define the multipliers allowed on an annual basis to alternative NTS capacity products.

The model user can define up to five scenarios for multipliers that apply to each financial year in the model. The model user then selects the scenario applied for the model run as part of the options in Control Sheet 2.

2.3.4. Control sheet 4

Control Sheet 4 contains triggers for VBA macros to run the model calculations on either an annual basis or for the full model period (2014/15 to 2028/29).

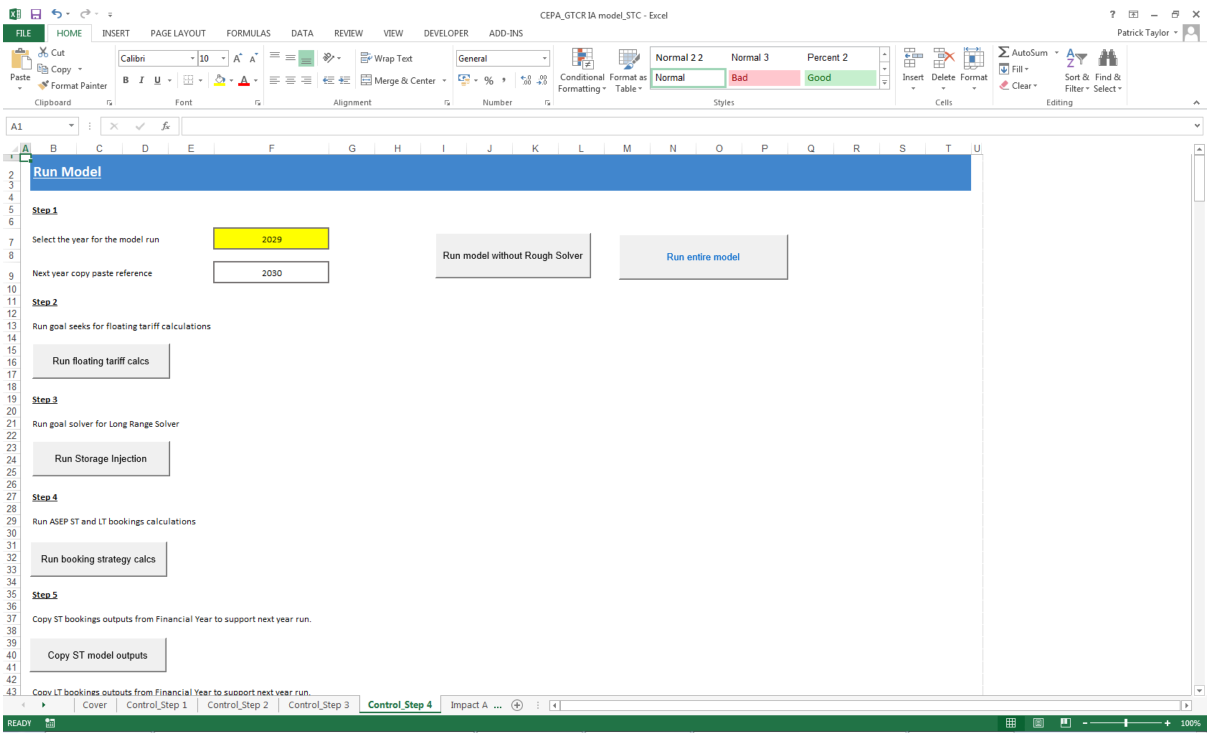
The model can be run for all years using:

- historical Rough storage flows (to match with the financial year wholesale price index scenario selected) in which case the macro "Run model without Rough solver" should be run by the model user;
- modelled Rough storage flows (using a solver and arbitrage modelling framework as described later in the report) in which case the macro "Run entire model" should be run by the model user.

The former (i.e. model run based on historic flows) allows much faster running of the model and may be preferable for testing model results.

The model can also be run for an individual model year by selecting the required year in the yellow input cell and running the individual macros defined as Steps 2 to 4 in the model run calculations. If Rough flows are modelled (i.e. determined within the model rather than based on historic flows selected within Control Sheet 1 and 2), then the storage injection macro must be run for the financial year.[20]

Figure 2.4: Control Sheet 4



Source: CEPA and TPA

2.4. Notes on control sheets

In undertaking a model run, the model user should work progressively through each of the control sheets in turn. When comparing results from alternative policy scenarios, we would

[20] The model can also be run mechanically for a single financial year using historic flows from Rough through a parameterised input switch in Control Sheet 2.

also suggest that consistent wholesale price, demand and storage inputs assumptions are used for each financial year in the model (as defined in Control Sheet 1).

3. KEY STAGES IN MODEL CALCULATIONS

In this section we focus on the approach used to model flows (dispatch) by ASEP and user booking of NTS entry capacity.

The requirement of the GTCR to model gas flows and NTS bookings by ASEP in response to changes in NTS charges is a very challenging task, particularly given the uncertainty of the future supply and demand structure in GB over the period 2015 to 2029. Therefore, a series of assumptions and simplifications have been necessary.

This section describes those key methodological assumptions and how they influence the methodological framework of the GTCR model. We also describe potential refinements to the GTCR model that Ofgem could consider as part of its future development should it want to extend the model's functionality.

3.1. Flow modelling

We have developed a scenario based modelling framework of daily supply flows (dispatch) to the GB gas market which is then used to determine the demand for NTS capacity in each financial year and the responsiveness of demand for different forms of capacity product in response to changes in the structure and level of NTS prices.

A supply and demand scenario for each gas day is identified drawing on assumptions from the "Gone Green" and "Slow Progression" long term planning scenarios in National Grid's Ten Year Statement. These scenarios are inputs to the modelling and, therefore, other Future Energy Scenarios could in theory be used within the model.[21]

Note that the model uses the NGG long term planning scenarios only as a source for assumptions in the daily and annual supply dispatch modelling. Annual demand, for example, is consistent with the selected planning scenario but the supply mix used to balance supply and demand is determined within the model. The approach taken to model daily flows by supply source (by ASEP) is described further below.

Figure 3.1 summarises the different steps in the flow modelling with each step then described in further detail in the subsections which follow.

[21] For example, National Grid's 2014 Future Energy Scenarios include two extra scenarios, Low Carbon Life and No Progression.

Figure 3.1: Dispatch modelling methodology

1) Take wholesale traded price input projections for each gas day and each year in the impact assessment

2) Determine – under modelled tariff policy options – the cross-border flows of interconnectors

3) Determine storage flows for the gas year – import and export to the National Transmission System

4) Determine profiled beach supplies from UK Continental Shelf and Norway supply sources

5) Determine required LNG supplies to match supply with demand on each gas day

Source: CEPA and TPA

3.2. Wholesale prices

Traded wholesale prices (for NBP and neighbouring European traded hubs ZEE and TTF) are an input in the GTCR model. The model input sheets have, therefore, been left blank for the model user to input wholesale price data.

As described in the previous section, in Control Sheet 1, the model user selects a scenario for wholesale prices for each year using three years of financial year gas price data uplifted by an annual 3.0 per cent wholesale price change forecast.[22]

As a number of the modelling steps rely on forward price as well as day ahead spot price data, we have used day-ahead price data published by Bloomberg for NBP, ZEE and TTF[23] as the source of traded spot prices to develop the model.

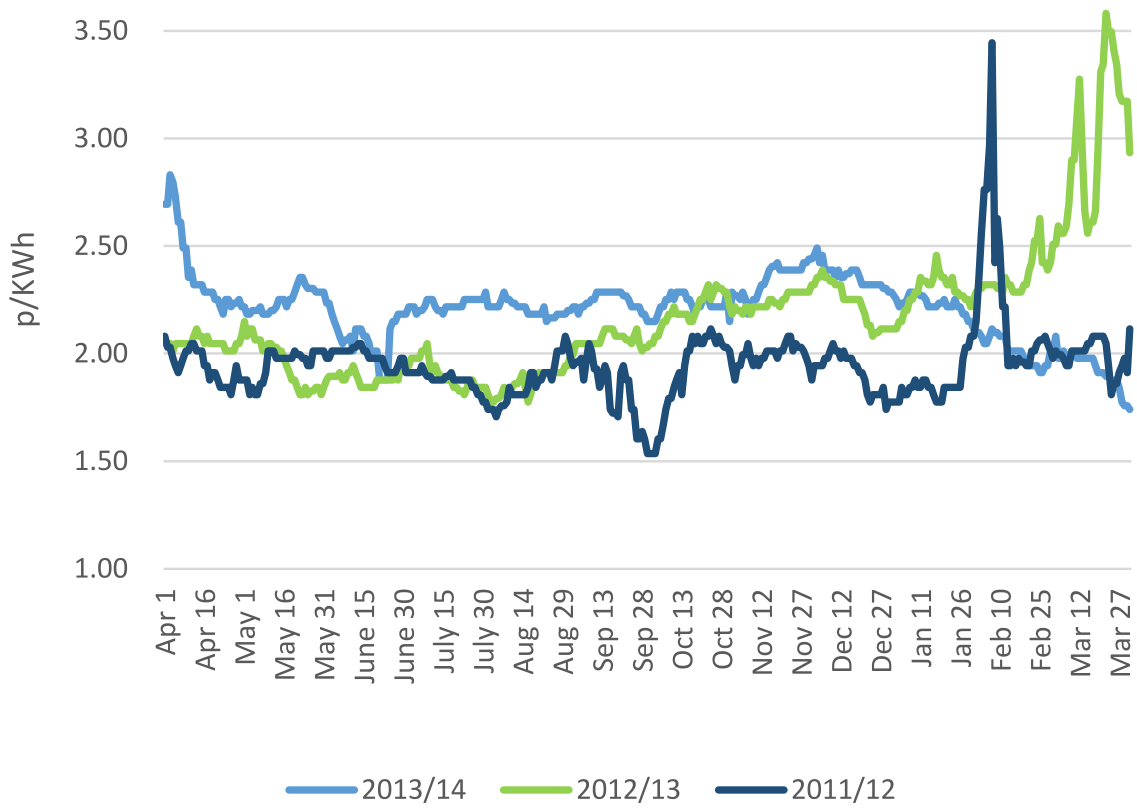
The original data series for all three trading hubs, however, has missing data on some dates (e.g. weekends) and in order to obtain values for those cases, we transformed the original series through an averaging method that uses value differences between the closest dates to those periods. In Annex C we have provided the price data tickers we used to source the Bloomberg data, so that other model users can potentially source the same data we used in developing the model.

[22] Wholesale gas prices will in practice not increase at the forecast level of RPI inflation. The three per cent assumption has been used to be consistent with the inflation indexing that is applied to transaction costs in arbitrage decisions and ensures that the size of transactions costs (in nominal terms) do not greatly exceed wholesale prices in the later years of the modelling period. This is an input assumption and so can be changed by the model user.

[23] National Balancing Point (NBP), Zeebrugge Hub (ZEE) and Title Transfer Facility (TTF).

Figure 3.2 illustrates the NBP wholesale prices used in developing the model based on financial years 2013/14, 2012/13 and 2011/12 data.

Figure 3.2: NBP wholesale day-ahead prices[24]



Source: Bloomberg and CEPA analysis

3.3. Cross-border flow modelling

Interconnectors

The arbitrage dispatch decisions of the two cross-border interconnectors are simulated in the model for each gas day in a financial year.

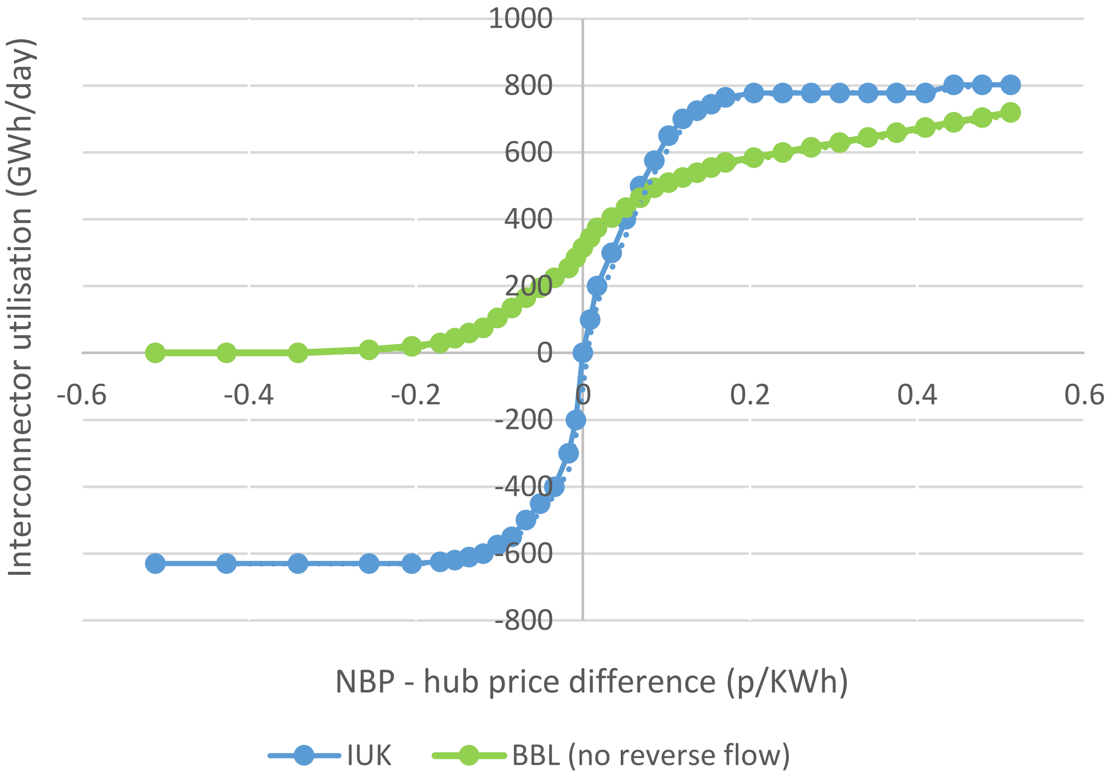
The interconnector flows are determined by the differentials in gas prices between European trading hubs, accounting for the marginal transaction costs which may be incurred in dispatch to and from NBP, ZEE and TTF hubs, including transmission network entry charges. The model includes the flexibility to assume that network *capacity* charges are treated as a sunk rather than variable cost in the arbitrage decision process.[25]

The IUK daily maximum import and export flows are assumed to be 803 GWh/day and 630 GWh/day respectively. As described above, we use the ZEE and NBP day-ahead prices

[24] Developed for 365 days in the year using the methodology described above.
[25] This is an assumption that can be selected in model Control Sheet 2.

(adjusted for transaction costs) as the basis to determine IUK flows. The supply elasticity of IUK dispatch in the model is determined by a user defined S curve to reflect the relationship between size of price differential and interconnector utilisation. The S curve currently input in the model for IUK is illustrated in Figure 3.3 below. [26]

Figure 3.3: Interconnector supply elasticity curves



Source: CEPA and TPA analysis

The daily maximum flow on the Balgzand Bacton Line (BBL) is assumed to be 557 GWh/day. No reverse flow is assumed to be possible on BBL up to a selected year, from which point the export capacity of BBL is set equal to its import capacity.[27] From the selected year for reverse flow capability, the model uses the same shape of supply elasticity curve as IUK for BBL, subject to the lower import/export maximum constraint on BBL's capacity.[28]

The shape of the S curve for both IUK and BBL flows was been determined by inspection of the historical relationship between size of price differential and size of import/export flow. For IUK, the S curve has been assumed to intercept the axis at zero as the relationship between flow and price differential is defined pre-application of marginal transaction costs. The implication of this is that were the NBP – ZEE *hub price* differential equal to zero, the

[26] The supply elasticity curve is a parameterised input within the model and so Ofgem can update/change this should it wish to do so.
[27] The date at which BBL has export capacity is a parameterised input within the model.
[28] Again this is a parameterised input in the model.

direction of flow will be influenced by the relative transaction costs incurred in dispatch from one market to the other.[29]

Capability for short haul flows is also included as part of the IUK daily flow modelling. Gas flowing into the NTS has the possibility to pay an optional short-haul tariff instead of the TO and SO commodity charge. The shorter the distance between entry and exit point and the larger the peak exit capacity the more attractive the short-haul tariff is. Therefore gas landed at Bacton Beach (including BBL and UKCS supplies) has the option to pay a short-haul tariff (rather than the TO and SO commodity charge) to export to IUK rather than selling at NBP and the quantity of short-haul volumes is determined as gas traded between NBP and ZEE.

Modelling of interconnector flows is discussed in further detail as part of Annex C.

Norway arbitrage

As well as BBL and IUK, a percentage of total annual available beach supplies from Norway is assumed to have swing capability and can flow to markets other than GB depending on the price differential (adjusted for transaction costs) between NBP, ZEE and TTF.

The model assumes daily deliverability of Norway arbitrage flows remains constant for each gas day for which a flow is determined in the model. Currently the model assumes daily deliverability as equal to 10 per cent of annual Norway capability (see section on beach supplies below) divided by 365 days.

Norway arbitrage supply capability is an input assumption in the modelling and so can be changed by Ofgem if an alternative assumption is preferred.

3.4. Storage modelling

Storage flows can be modelled differently for LRS (Rough) and for Medium Range Storage (MRS) and Short Range Storage (SRS).

For LRS, (Rough) injection and withdrawal flows are determined in stages based initially on a data driven approach and then refined to reflect how in reality we understand holders of capacity seek to exploit the value of a LRS facility. We describe the methodology used for Rough in Annex D. Alternatively the model user can also choose to select Rough injection and withdrawal historic flows to match the financial year wholesale price index used.

For MRS and SRS facilities, the GTCR model adopts a more simplified scenario based approach. In reality, storage flows for shorter range storage facilities adopt a trading strategy which depends on a series of variables that are beyond the scope of the modelling exercise undertaken for the GTCR review. For example, MRS modelling is complicated by the need to

[29] Historical analysis of IUK flows versus hub price differentials shows that the interconnector can be in export mode even where NBP prices are higher than ZEE prices because of marginal transaction costs (such as NTS commodity charges and short haul tariffs) influencing profitability of alternative dispatch opportunities.

model storage flows by ASEP (rather than at an aggregated level) to a degree of accuracy so as to determine future booking requirements.

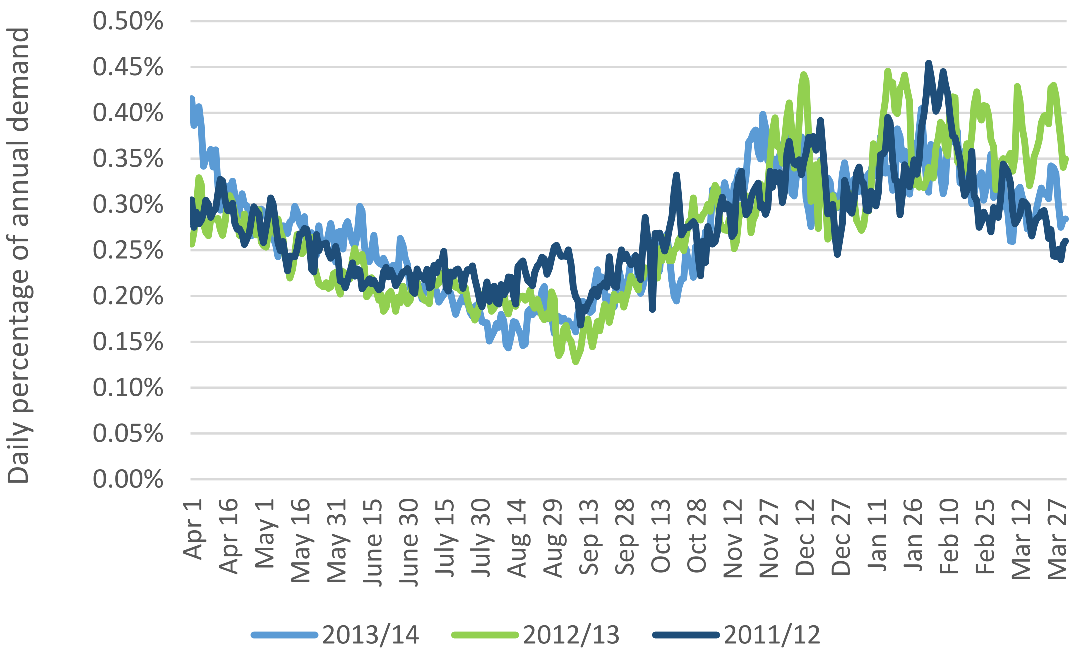
Therefore, MRS and SRS storage flows are applied as an input in the model based on historical injection and withdrawal flows which match the NBP wholesale prices for the financial year applied in the model scenario. We have sourced historical flows by storage facility from NGG's gas transmission operational data site.[30]

3.5. Beach supplies

Annual totals from the selected Ten Year Statement scenario for UK Continental Shelf (UKCS) and Norway beach supplies are used in the model (e.g. Gone Green or Slow Progression). UKCS supplies are split by ASEP based on the proportion of historical supplies for 2012/13 to each entry point. We make the simplifying assumption that flows from each ASEP decline equally with the projected decline in annual totals.

For Norway supplies, we take the remaining percentage of the annual total in the NGG Ten Year Statement scenario, after a percentage of supplies are allocated as arbitrage flows (as described in Section 3.3.2 above). Annual beach supplies for the year (by ASEP) are profiled based on historical daily NTS demand as a proportion of annual demand (the index used matches the financial year of wholesale prices used in the model (see Figure 3.4)).

Figure 3.4: Daily profiles for beach supplies



Source: CEPA and TPA and NGG operational data

[30] http://www2.nationalgrid.com/uk/industry-information/gas-transmission-operational-data/

On certain gas days, the combination of beach and simulated supplies from other modelled sources (excluding LNG) can exceed daily demand. On these days, the model constrains all ASEP beach supplies to balance supply and demand; however, the displaced volumes are then reallocated in other days in the year to replace non beach supplies that would otherwise have been required (on the basis of the merit order of alternative supply options).

This means that the annual totals for beach supplies are consistent with the NGG Future Energy scenario, but the profile of supplies can differ slightly from the constructed index for the gas year of daily profiled beach supplies.

3.6. LNG supplies

LNG supplies act as the swing supply source in the flow modelling to balance daily supply by ASEP with daily NTS demand.

The model constructs a net daily demand value having deducted (or added in the case of pipeline exports and storage injections) interconnector, storage and beach supply flows from daily demand. (As described above and in Section 4, daily demand is based on annual demand from National Grid's Ten Year Statement scenarios, profiled based on historical daily offtake proportions of annual totals from the NTS for historical years, again to match the wholesale prices used in the modelling year).

We assume that LNG supplies from Milford Haven are dispatched first and, therefore, Isle of Grain supplies act as the final source of supply to balance supply and demand. The requirement for LNG supplies therefore reflects the interaction of the profile of demand and beach supplies assumed in the modelling.

3.7. Booking strategy modelling

3.7.1. Approach

A key part of the GTCR model is simulating the price responsiveness of demand for NTS capacity from changes in the structure of entry charges.

Demand to flow gas on the NTS for each gas day is determined through the supply and demand scenario modelling described in the previous subsection. In this second stage, the GTCR model determines a shipper's booking strategy given a gas day flow requirement. This involves modelling the expected cost or value of NTS capacity from the perspective of different supply sources that wish to flow to or from the GB market.

The model considers the value of NTS capacity (by valuing the cost of an ASEP constraint) for the following supply sources and by ASEP:

- dry gas fields;
- associated gas fields;
- condensate gas fields

- LNG;
- storage;
- interconnector (committed import) pipeline; and
- interconnector (arbitrage) pipeline.

The mix of supplies (dry gas, associated gas and condensate gas) for UKCS supplies as individual ASEPs are a parameterised input to the model (see Section 4).

The GTCR model (by ASEP) then considers:

- the full economic (opportunity) cost (by supply source) of a requirement for NTS capacity not being available to support flow into the NTS;
- the probability of a constraint at an ASEP to determine the *expected* loss of revenue and, therefore, value of an ASEP constraint; and
- given the cost of booking long term or short term entry capacity, whether (on an expected value basis) a network user, for a given capacity requirement, would be better or worse off from booking long term capacity.

The expected probability of a constraint is determined through a series of steps and an assumed relationship between forecast daily flow and capacity:

- the model takes the forecast ASEP daily flow and, therefore, capacity requirement for the gas day, and reduces the capacity requirement by known (existing) QSEC bookings at each individual ASEP;[31]
- the ratio of net flow to net technical capacity[32] (flow and technical capacity reduced by known QSEC bookings for the quarter) is then used to determine a probability of a constraint (as described below).

The GTCR model applies a user-defined curve[33] to determine the probability of a constraint at an ASEP based on the modelled net flow to net capacity ratio. The current parameters underlying the probability curve are:

- when the net flow to net capacity ratio is less than 50 per cent, the probability of constraint at an ASEP is equal to zero;
- the probability of constraint rises gradually for a net flow to capacity ratio greater than 50 per cent to reach a value of 10 per cent when the ratio is equal to 100 per cent;

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[31] As described below, this assumes that all existing bookings at an ASEP are in the first instance nominated against forecast flows on an individual gas day.

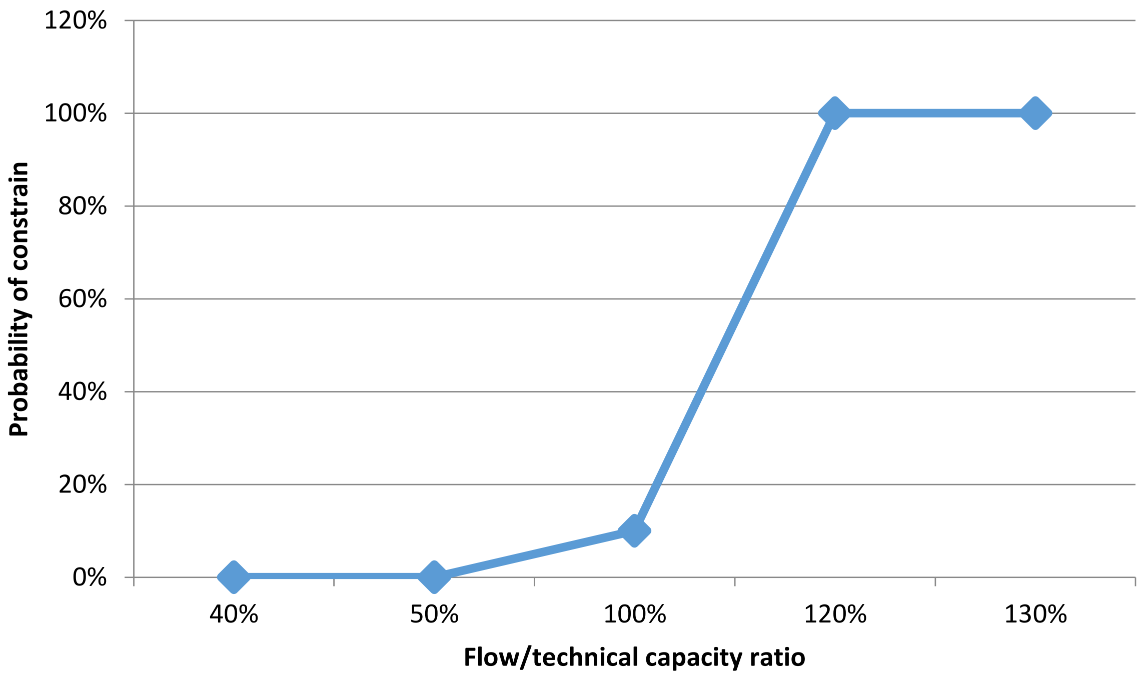
[32] We use obligated capacity levels as a proxy for technical capacity.

[33] This is a parameterised input within the model that can potentially be changed by the model user. Inherently the shape of the curve reflects the degree of risk aversion of the shipper user of an ASEP.

- for a net flow/capacity ratio greater than 100 per cent, the probability of constraint rises faster up to a value of 100 per cent when the net flow/capacity ratio is equal to 120 per cent.

These assumptions result in a linear (kinked) probability of ASEP constraint curve, as illustrated in Figure 3.5 below.

Figure 3.5: Probability of constraint curve



Source: CEPA and TPA

The process described above determines (on a daily basis) whether a flow requirement prefers the certainty of a long term capacity product or the potential cost savings (under the tariffing regime) of a short term capacity product. However, in practice a network user can only achieve the certainty of a long term product by buying QSEC for the quarter of a financial year rather than an individual day.[34]

The model then adopts a simple rule of thumb to determine a quantity of new QSEC bookings at the ASEP. If for more than two thirds of the days within a quarter a shipper at an ASEP would prefer the certainty of long term (QSEC) rather than short term capacity to fulfil forecast daily ASEP flow requirements, QSEC is assumed to booked by shippers for the maximum forecast ASEP flow in the quarter.

[34] This is a simplification from reality of course as there are annual and rolling monthly auctions of monthly NTS capacity.

This assumes that network users book for the forecast quarterly peak where it is in their interest (on an expected value basis) to book long term rather than short term capacity with the certainty of network access long term capacity brings. The model user can select an alternative rule of thumb to two thirds of the days as an input parameter, if a less or more restrictive assumption on bookings needed to be investigated.

3.7.2. Assumptions / simplifications

The booking strategy modelling assumes:

- all existing capacity bookings at an ASEP are in the first instance nominated against forecast flows; and therefore
- an existing capacity holding not used by one shipper would be sold on the secondary market to another shipper.[35]

The model also does not explicitly take into account the process of capacity substitution[36]. However, the ability for NGG to switch capacity away from terminals with a low user commitment, we believe sharpens the importance of factoring in the probability of a constraint where the flow to technical capacity ratio exceeds 50 per cent.

Currently the GTCR model also applies a single probability curve to all ASEPs. As described below, there are alternative assumptions which Ofgem might consider for modelling the probability of a constraint on a more varied basis by ASEP should there be a desire to extend the model's functionality.

Annex E provides a more detailed description of the assumptions and input data which are used in the capacity booking strategy modelling (e.g. the approach taken to model the economic cost of an ASEP constraint by supply source).

3.8. Model sensitivities and potential refinements

The GTCR model results (e.g. the structure and incidence of revenue recovery under alternative NTS entry charging options) are sensitive to the assumptions described above on NTS capacity booking and projected annual supplies sourced from alternative NTS entry points over the modelling period (2014/15 to 2028/29).

The projected tariff levels (e.g. required floating adjustments to recover target revenue) are therefore heavily influenced by the framework of gas supply and demand that has been applied within the modelling.

Projected tariff levels are also sensitive to:

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[35] This means the full existing capacity holding at an ASEP is in the first instance used to support a forecast flow.

[36] Substitution is the process whereby capacity at the obligated level is reduced due to substitution to another ASEP in certain circumstances where the committed long term demand (and not the projected short term need) at the (donor) ASEP is less than the obligated level whilst long term demand at another (recipient) ASEP is greater than the obligated level.

- the projected future level of inflation (currently 3 per cent per annum in the model) that is used to uplift Transporter allowed revenues and capacity prices (e.g. under a inflation adjusted tariff regime reform option); and
- the allocation of NGG transmission SO and TO price control revenues between the target revenue pots used to set SO commodity and TO capacity and commodity charges (where applicable).

As regards the allocation of SO and TO allowed revenue, the model allows the user to input an SO *commodity charge* target revenue to reflect SO variable costs (e.g. shrinkage) rather than total SO price control revenues. As described in Section 4, any difference between the SO commodity charge target revenue and the SO price control allowed revenue is assumed in the model to then be recovered through TO capacity and commodity charge target revenue. Whilst the model has been developed on this basis, an alternative split of SO and TO revenue recovery can be input by the model user.

Modelled cross-border flows (export to and import from the continent) also appear relatively sensitive to the level of marginal transaction costs (e.g. BBL forward flow transport costs) which are included in European hub price arbitrage modelling.

The following input sensitivities within the GTCR model could, therefore, be investigated by Ofgem in producing a future GTCR impact assessment:

- the sensitivity of the results, under alternative combinations of the options being considered as part of the GTCR, could be investigated under alternative assumptions of future inflation;
- a scenario where marginal transaction costs have a reduced impact on cross-border flows might be investigated by assuming shippers treat capacity charges as sunk costs (this is included in the current model functionality); and
- different scenarios for the allocation of SO and TO price control revenues under alternative (e.g. TAR FG compliant) recovery mechanisms of target allowed revenues could be agreed with relevant industry stakeholders.

The following refinements to the GTCR model could also be considered by Ofgem should it wish to extend its functionality:

- variation of the assumption that LNG imports act as the balancing supply option in the daily supply modelling;
- instead of the simple rule used to determine the QSEC bookings (described above), an optimisation algorithm could be developed that minimises the total cost of booking capacity (short term and long term) for each quarter[37];

[37] For example, minimise total cost of capacity bookings as: cost of QSEC bookings (New QSEC * price* no of days) + cost of short term bookings (cost of capacity bookings + expected value of constraint). This may reduce the level of QSEC booked from the peak flow in any given quarter.

- allow the model user to specify different mixed capacity booking strategies as an initial and alternative case in capacity bookings that could potentially be adopted by supply sources at individual ASEPs;
- as described above, the model applies a single probability curve to all ASEPs and supply sources – one possible development would be to have three constraint curve options to reflect alternative states of risk aversion:
    - one where there is never the risk of constraint (e.g. ASEPs where there is expected to be a single user);
    - one 'normal' curve such as the one illustrated above where the probability of a constraint is discounted at low flow / technical capacity ratios; and
    - one where a higher degree of risk aversion means that LT bookings happen at lower probabilities of constraint.
- at the margin, the incentive to flow from sources of supply and flexibility such as LNG and MRS may be affected by changes in the structure of NTS prices. This could be accommodated in the daily flow modelling.

4. Model Input Data

In this section we outline the GTCR model assumptions. We document the model assumptions and the source of input data according to following sub-headings:

- general input assumptions;
- wholesale pricing data;
- cross-border flow transaction costs;
- NTS capacity, network and peak supply data;
- allowed revenue;
- supply assumptions and data;
- booking strategy assumptions; and
- demand assumptions and data.

We consider each element in turn.

4.1. General assumptions

€/£ exchange rate	
Description	Euro – Pound exchange rate
Value	0.8
Units	€/£
Source	CEPA/TPA assumption – can be varied in the model for each financial year by the model user

$/£ exchange rate	
Description	Dollar – Pound exchange rate
Value	1.7
Units	$/£
Source	CEPA/TPA assumption – can be varied in the model for each financial year by the model user

Europe inflation	
Description	Inflation percentage applied to continental supply transaction costs
Value	2 per cent

Europe inflation	
Units	%
Source	CEPA/TPA assumption – can be varied in the model by the model user

UK inflation	
Description	RPI inflation percentage applied to uplift allowed revenues and UK based costs and inputs to the model
Value	3 per cent
Units	%
Source	CEPA/TPA assumption – can be varied in the model by the model user

4.2. Wholesale price data

NBP day-ahead and forward prices	
Description	NBP day ahead prices and forward prices for each gas day for previous financial years Converted into p/kWh from p/therm
Value	Various
Units	p/kWh
Source	Bloomberg

ZEE day-ahead prices	
Description	ZEE day ahead prices for each gas day for previous financial years Converted into p/kWh from £/therm
Value	Various
Units	p/kWh
Source	Bloomberg

TTF day-ahead prices	
Description	ZEE day ahead prices for each gas day for previous financial years Converted into p/kWh from £/MWh

TTF day-ahead prices	
Value	Various
Units	p/kWh
Source	Bloomberg

4.3. Cross border flow transaction costs

GTS Entry Charge	
Description	Entry charge paid for cross-border flows from GB to the Netherlands. We take the JULIANADORP (BBL) tariff for 2014 as the starting assumption in the model and uplift this by an annual European inflation assumption of two per cent.
Value	1.733
Units	€/kWh/hour/day
Source	http://www.gasunietransportservices.nl/en/products-services/terms-and-conditions/tsc

GTS Exit Charge	
Description	Exit charge paid for cross-border flows from Netherlands to the GB. We take the JULIANADORP (BBL) tariff for 2014 as the starting assumption in the model and uplift this by an annual European inflation assumption of two per cent.
Value	1.224
Units	€/kWh/hour/day
Source	http://www.gasunietransportservices.nl/en/products-services/terms-and-conditions/tsc

Bacton Beach short-haul	
Description	Short-haul tariff for Bacton
Value	0.02
Units	p/therm
Source	IUK response to Ofgem call for evidence on use of GB gas interconnectors

Bacton Beach short-haul	
	https://www.ofgem.gov.uk/ofgem-publications/59256/iuk-response-call-evidence-use-gas-interconnectors-gbs-borders.pdf

IUK Transport costs	
Description	Flow based charge for use of IUK forward and reverse flow capacity until 2018 Flow based charge and potential transportation charge from 2018
Value	0.05 until 2018 and 0.1 from 2018
Units	p/therm
Source	Pre 2018 assumption source from IUK response to Ofgem call for evidence on use of GB gas interconnectors https://www.ofgem.gov.uk/ofgem-publications/59256/iuk-response-call-evidence-use-gas-interconnectors-gbs-borders.pdf Post 2018 assumption sourced from IUK response to CMP implementation consultation http://www.interconnector.com/media/63031/130430_iuk_consultation_on_cmp_implementation.pdf

BBL Transport costs (forward flow and physical reverse flow)	
Description	Transportation (e.g. fuel) charge for use of BBL forward and (physical) reverse flow capacity. Average assumption for the year as charge can vary by season.
Value	0.008 (derived from 0.1 €/MWh)
Units	p/kWh
Source	Suggested assumption by member of the GTCR Technical working group

4.4. NTS capacity, network and peak supply and demand data

Obligated capacity	
Description	Baseline NTS Entry Capacity (obligated) – as defined by National Grid's Gas Transporter Licence – plus capacity substitution and legacy TO entry capacity. Bacton Obligated capacity is split according to size of technical capacity of IUK and BBL. Remaining capacity is allocated to Bacton Beach (non-CAM point).

Obligated capacity	
	As per Ofgem 'Options for Great Britain's implementation of the European Union Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems (Regulation 984/2013) at the Bacton entry point.
Value	Various – varies by ASEP and financial year
Units	GWh
Source	NGG Transportation Licence Bacton split - https://www.ofgem.gov.uk/publications-and-updates/options-great-britain%E2%80%99s-implementation-european-union-network-code-capacity-allocation-mechanisms-gas-transmission-systems-regulation-9842013-bacton-entry-point-0

Peak supply and demand	
Description	Peak supply and demand flows by ASEP and financial year (current version of model is populated under the Slow Progression and Gone Green scenarios).
Value	Various – varies by ASEP and financial year
Units	GWh
Source	National Grid 2013 Gas Ten Year Statement http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Gas-Ten-Year-Statement/

Existing QSEC bookings	
Description	QSEC bookings (baseline and incremental) by ASEP by financial year quarter. Existing QSEC bookings at Bacton CAM and Bacton Beach are split using the same proportions as used to split obligated capacity.
Value	Various – varies by ASEP and financial year
Units	GWh/day
Source	National Grid – input data in model derived from CEPA calculations and analysis

Short term bookings	
Description	Includes input data for MSEC bookings, DADSEC bookings, WDDSEC Bookings and DISEC bookings.

Short term bookings	
	Actual bookings for the financial year 2013/14 are used in the model whilst future years are an output of the booking strategy modelling. Outputs from the booking strategy modelling are inputs to future tariff calculations.
Value	Various – varies by ASEP and financial year
Units	GWh/day
Source	National Grid – input data in model derived from CEPA calculations and analysis

Nodal Marginal Distance	
Description	Output of the Transportation model when running under the peak supply and demand scenario for the financial year. These are used to calculate final tariffs under the floating tariff adjustment policy options. We have run the Transportation model for each year from 2014/15 to 2029/30 using peak supply and demand data from NGG's 2013 Gas Ten Year Statement to produce Long Run Marginal Costs (KMs) for each ASEP which are then used to determine future reserve prices for new capacity bookings in the tariff modelling. As we use the Ten Year Statement peak supply and demand data, the underlying LRMCs used in the modelling do not change by policy scenario (although the secondary adjustments applied to the LRMCs and which are used to arrive at final tariffs do change by the model scenario). For this reason, the LRMCs are an input in the model rather than being calculated within the Excel spreadsheet.
Value	Various – varies by ASEP and financial year
Units	Kilometres (km)
Source	CEPA analysis of NGG Transportation model run under Slow Progression and Gone Green scenarios

Initial price schedule	
Description	Output of the Transportation model when running under the peak supply and demand scenario for the financial year. These are the 50:50 adjusted reserve prices that currently applied in QSEC auctions. They are derived from applying the Slow Progression and Gone Green scenario peak supply and demand data sourced from the Ten Year Statement.

Initial price schedule	
	See comments on nodal marginal distance calculations outlined above.
Value	Various – varies by ASEP and financial year
Units	p/kWh/day
Source	CEPA analysis of NGG Transportation model run under Slow Progression and Gone Green scenarios

Expansion constant	
Description	The capital cost of the transmission infrastructure investment required to transport 1 GWh over 1 km. Its magnitude is derived from the projected cost of an 85bar pipeline and compression for a 100km NTS network section. The GTCR model takes the Transportation model expansion constant applicable for 2017/18 and indexes it for previous and future years to inflation.
Value	Various – varies by ASEP and financial year
Units	£/GWhkm
Source	CEPA analysis of NGG Transportation model input

4.5. Allowed revenue

General assumption	
Description	Target revenue for SO commodity charge revenues are as per SO price control until 2016/17. From 2016/17, model user can input a target SO commodity charge revenue pot – e.g. target SO commodity charge revenue pot set to recover variable SO costs (e.g. shrinkage). The difference between the SO price control allowed revenue and the target SO commodity charge revenue is then added to the target TO charging revenue. In developing the model, £100m has been used as a starting value for a target SO commodity allowed revenue pot, which is then uplifted for inflation in future years.
Value	Various – varies by financial year
Units	N/A
Source	Assumption – can be varied in the model

TO allowed revenue	
Description	The Transporter Owner allowed revenue to be recovered from NTS capacity and commodity charges (where applicable). We take the allowed revenue figures for RIIO-T1 for the years 2014/15 to 2020/21 then assume allowed revenues remain constant in 09/10 prices from 2021/22 onwards.
Value	Various – varies by financial year
Units	£m - 09/10 prices
Source	Ofgem, Final RIIO-T1 determination

SO allowed revenue	
Description	The System Operator allowed revenue to be recovered from NTS capacity and commodity charges (where applicable). We take the allowed revenue figures for RIIO-T1 for the years 2014/15 to 2020/21 then assume allowed revenues remain constant in 09/10 prices from 2021/22 onwards.
Value	Various – varies by financial year
Units	£m - 09/10 prices
Source	Ofgem, Final RIIO-T1 determination

Excluded services revenue	
Description	Services provided by the licensee as part of its business in respect of which the charges may be treated as falling outside the scope of the charge restrictions otherwise imposed by or under the licence.
Value	£3m - Fixed (09/10 price) assumption for all years
Units	£m - 09/10 prices
Source	Ofgem, Final RIIO-T1 determination

Pass through costs	
Description	Costs that are a pass-through under the charge restriction of the Transporter licence
Value	£19.5m - Fixed (14/15 price) assumption for all years
Units	£m - 14/15 prices
Source	National Grid charge setting report (Indicative Notice October 2014)

Pass through costs	
	http://www2.nationalgrid.com/UK/Industry-information/System-charges/Gas-transmission/Tools-and-Models/

Output incentive	
Description	Revenues earned by the Transporter under the financial incentives of the price control.
Value	£0m - Fixed assumption for all years
Units	£m - 14/15 prices
Source	National Grid charge setting report (Indicative Notice October 2014) http://www2.nationalgrid.com/UK/Industry-information/System-charges/Gas-transmission/Tools-and-Models/

K-Factor	
Description	Adjustment to allowed revenues to account for an under or over recovery in the previous year. The model determines the K-factor based on previous year over and under recoveries.
Value	£0m – for 2014/15 and then determined within the model based on previous year outputs.
Units	£m
Source	National Grid charge setting report (Indicative Notice October 2014) http://www2.nationalgrid.com/UK/Industry-information/System-charges/Gas-transmission/Tools-and-Models/

DN Pensions	
Description	Pensions deficit charge as allowed under the price control arrangements.
Value	£42.5m - Fixed (14/15 prices) assumption for all years
Units	£m - 14/15 prices
Source	National Grid charge setting report (Indicative Notice October 2014)

DN Pensions	
	http://www2.nationalgrid.com/UK/Industry-information/System-charges/Gas-transmission/Charging-Statements/

Metering	
Description	Revenue allowance under the Transporter price controls for metering costs.
Value	£1.7m - Fixed (14/15 price) assumption for all years
Units	£m - 14/15 prices
Source	National Grid charge setting report (Indicative Notice October 2014) http://www2.nationalgrid.com/UK/Industry-information/System-charges/Gas-transmission/Tools-and-Models/

Constraint management CM	
Description	Revenue allowance under the Transporter price controls associated with constraint management.
Value	£31.3m - Fixed (14/15 price) assumption for all years
Units	£m - 14/15 prices
Source	National Grid charge setting report (Indicative Notice October 2014) http://www2.nationalgrid.com/UK/Industry-information/System-charges/Gas-transmission/Tools-and-Models/

S0 external incentive adjustment (SOOIRC)	
Description	Revenue allowance under the Transporter price controls associated with System Operator incentives.
Value	£131m - Fixed (14/15 price) assumption for all years
Units	£m - 14/15 prices
Source	National Grid charge setting report (Indicative Notice October 2014) http://www2.nationalgrid.com/UK/Industry-information/System-charges/Gas-transmission/Tools-and-Models/

SO Transportation Support Services revenue adjustment (TSS)	
Description	Revenue allowance under the Transporter price controls associated with support services
Value	£8.7m - Fixed (14/15 price) assumption for all years
Units	£m - 14/15 prices
Source	National Grid charge setting report (Indicative Notice October 2014) http://www2.nationalgrid.com/UK/Industry-information/System-charges/Gas-transmission/Tools-and-Models/

Reductions for SO capacity	
Description	Revenue adjustments by three categories – non-obligated, legacy entry and legacy exit.
Value	£0.6m; £4.6m; £10.6m respectively - Fixed (14/15 price) assumption for all years
Units	£m - 14/15 prices
Source	National Grid charge setting report (Indicative Notice October 2014) http://www2.nationalgrid.com/UK/Industry-information/System-charges/Gas-transmission/Tools-and-Models/

Neutrality adjustment	
Description	Revenue adjustment for balancing neutrality charge and Capacity neutrality revenue(both allowance and revenue - so ignored)
Value	£6m - Fixed (14/15 price) assumption for all years
Units	£m - 14/15 prices
Source	National Grid charge setting report (Indicative Notice October 2014) http://www2.nationalgrid.com/UK/Industry-information/System-charges/Gas-transmission/Tools-and-Models/

Other SO revenue adjustments	
Description	Includes Buyback cost recovered via Capacity neutrality, St Fergus Compression and Short-haul.

Other SO revenue adjustments	
Value	£0m; £14.7m; £16.6m respectively; Fixed (14/15 price) assumption for all years
Units	£m - 14/15 prices
Source	National Grid charge setting report (Indicative Notice October 2014) http://www2.nationalgrid.com/UK/Industry-information/System-charges/Gas-transmission/Tools-and-Models/

4.6. Supply assumptions and data

UK Continental Shelf – annual supply capability	
Description	Total volume of gas available from the UKCS for each year in the model.
Value	Various
Units	GWh
Source	National Grid 2013 Gas Ten Year Statement http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Gas-Ten-Year-Statement/

UK Continental Shelf – mix of gas fields	
Description	Modelling of the value of constraint requires assumptions of the volume of gas that is sourced from Associated, Condensate and Dry Gas fields. The model currently is populated with numbers which assume 45% of volumes are Associated Gas based, 10% of volumes Condensate based and 45% Dry Gas field based.
Value	Fixed assumption but can be varied by ASEP
Units	Proportion factor
Source	CEPA assumption

Norway – annual supply capability	
Description	Total volume of gas available from Norway imports for each year in the model.
Value	Various
Units	GWh

Norway – annual supply capability	
Source	National Grid 2013 Gas Ten Year Statement http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Gas-Ten-Year-Statement/

Proportion of Norway contracted supplies to GB	
Description	Proportion of annual supply capability contracted to flow to the GB market.
Value	90%
Units	Proportion factor
Source	CEPA assumption – can be varied within the model Annual volumes are derived from National Grid 2013 Gas Ten Year Statement

Proportion of Norway arbitrage supplies available to flow to GB	
Description	Proportion of annual supply capability with flow optionality to the GB market subject to arbitrage rule.
Value	10%
Units	Proportion factor
Source	CEPA assumption – can be varied within the model Annual volumes are derived from National Grid 2013 Gas Ten Year Statement

Milford Haven daily supply capability	
Description	Maximum dispatch quantity on each day set equal to ASEP obligated capacity level.
Value	950 GWh/day
Units	GWh/day
Source	CEPA assumption – can be varied within the model

Isle of Grain daily supply capability	
Description	Initial maximum dispatch quantity on each day set equal to ASEP obligated capacity level. As the swing supply source, where Isle of Grain supplies greater than obligated capacity are required to balance supply and demand, this maximum capability assumption is relaxed to balance supply and demand.

Isle of Grain daily supply capability	
	This effectively assumes the triggering of investment in ASEP capacity and import capability.
Value	700 GWh/day
Units	GWh/day
Source	CEPA assumption – can be varied within the model

4.7. Booking strategy assumptions

Gas field profit margin	
Description	Upstream profit margin on the traded price at the beach associated with the ASEP.
Value	50% - Fixed assumption
Units	Percentage
Source	CEPA/TPA assumption – can be varied within the model – based on our judgement of the potential profit margin of gas traded at the beach

LNG profit margin	
Description	Upstream profit margin on the traded price at the ASEP for LNG supplies.
Value	59% - Fixed assumption
Units	Percentage
Source	CEPA/TPA assumption – can be varied within the model – based on a judgement of the potential profit margin of LNG imported gas traded at the ASEP

Gas price at ASEP	
Description	The traded gas price at an ASEP used to derive the expected value of a constraint.
Value	30 p/therm for Associated Gas; 35p/therm for Condensate Gas; 40 p/therm for Dry Gas; 50 p/therm for LNG
Units	p/therm
Source	CEPA/TPA assumption – can be varied within the model – again based on a judgement of typical prices that beach supplies and LNG can be traded at an ASEP

Value multiplier for beach supply gas source	
Description	Value multiplier achieved by the shipper from the traded spread between the NBP price and the ASEP price.
Value	95% for Associated Gas; 100% for Condensate Gas; 105% for Dry Gas
Units	Percentage
Source	CEPA/TPA assumption – can be varied within the model – based on a judgement of the traded gas value achieved by a beach supply at the ASEP

Value multiplier for LNG	
Description	Value multiplier achieved by the shipper from the traded spread between the NBP price and the ASEP price.
Value	100%
Units	Percentage
Source	CEPA/TPA assumption – can be varied within the model – based on a judgement of the traded gas value achieved by LNG supplies at the ASEP

Oil production assumption for Associated Gas fields	
Description	Oil production for a given volume of gas production (as determined by flow modelling).
Value	1000
Units	bb/MMscfd
Source	CEPA/TPA assumption – can be varied within the model

Liquids production assumption for Associated Gas fields	
Description	Liquids production for a given volume of gas production (as determined by flow modelling).
Value	0
Units	bb/MMscfd
Source	CEPA/TPA assumption – can be varied within the model

Liquids production assumption for Condensate Gas fields	
Description	Liquids production for a given volume of gas production (as determined by flow modelling).
Value	100
Units	bb/MMscfd
Source	CEPA/TPA assumption – can be varied within the model

Liquids production assumption for Dry Gas fields	
Description	Liquids production for a given volume of gas production (as determined by flow modelling).
Value	3
Units	bb/MMscfd
Source	CEPA/TPA assumption – can be varied within the model

Oil profit margin	
Description	Profit on the traded value of oil production from an Associated Gas field
Value	50%
Units	Percentage
Source	CEPA/TPA assumption – can be varied within the model - based on a judgement of the traded value achieved by a beach supply at the ASEP

Liquids profit margin	
Description	Profit on the traded value of liquids production from an Condensate and Dry Gas field
Value	50%
Units	Percentage
Source	CEPA/TPA assumption – can be varied within the model - based on a judgement of the traded value achieved by a beach supply at the ASEP

Liquids price	
Description	Traded value of liquids production from an Condensate and Dry Gas field
Value	100

Liquids price	
Units	$/bbl
Source	CEPA/TPA assumption – can be varied within the model – based on current observed price levels

Oil production price	
Description	Assumed traded value of oil production from Associated Gas fields.
Value	100
Units	$/bbl
Source	CEPA/TPA assumption – can be varied within the model – based on current observed price levels

MRS ASEP Supply Value multiplier	
Description	Value achieved on an underlying summer winter intrinsic value ("Margin Spread") of a gas storage facility trade
Value	220%
Units	Percentage
Source	CEPA/TPA assumption – can be varied within the model

MRS Margin Spread	
Description	Value achieved on an underlying intrinsic value summer winter hedge for a gas storage facility
Value	220%
Units	Percentage
Source	CEPA/TPA assumption – can be varied within the model – see Annex E for further details

5. MODEL OUTPUTS

In this section we discuss some of the outputs produced by the GTCR model. We also illustrate outputs from a number of initial illustrative model runs.

5.1. Graphs

The graphs sheet in the model presents a series of outputs that are based on running the model for each year from 2014/15 to 2028/29.

1. **Capacity – commodity split in TO allowed revenue** – shows the percentage split of Transportation Owner (TO) allowed revenue recovered from entry capacity and commodity charges.
2. **Revenue recovery by booking** – shows the percentage split of capacity revenues recovered from the QSEC bookings as compared to Short Term bookings (MSEC, DADSEC, WDDSEC and DISEC).
3. **Revenue recovery by user group –** shows the percentage split of revenue recovery by NTS supply source (beach (UKCS excluding Easington supplies), storage (including Rough), LNG, CAM point (interconnector) and Easington supplies (excluding Rough)).
4. **Revenue recovery by ASEP** – shows TO allowed revenue, TO recovered revenue and recovered revenue for a number of key entry points, including Bacton CAM, Bacton UKCS, Easington and Rough, Milford Haven, Isle of Grain and St Fergus.
5. **Financial dispatch by year** – shows the stacked dispatch from alternative supply sources for the current financial year in the model (this will be 2029/30 for a full dynamic model run).
6. **Scenario annual flows** – shows annual flows by supply source in the model calculations. The graph illustrates UKCS, LNG, IC importation and Norway supplies (i.e. excludes storage flows).
7. **NTS tariffs** – shows the TO commodity charge, Average Daily (day ahead and interruptible) NTS entry capacity charges. The averages are calculated as the mean average of all ASEP capacity charges.
8. **Annual capacity tariff by ASEP** – shows capacity charges (p/kWh/day) for a subset of NTS entry points, including Bacton CAM, Bacton UKCS, Easington and Rough, Milford Haven, Isle of Grain and St Fergus.
9. **Entitlement by product** – shows capacity entitlement by product split by Long Term entitlement (QSEC) and Short Term entitlement (MSEC, DADSEC, WDDSEC and DISEC) and Total Entitlement.

10. **Bacton UKCS – bookings and obligated capacity** – shows sold QSEC in Quarter 1 (of calendar year), peak day flow for financial year, and obligated capacity release for the Bacton UKCS entry point.
11. **Easington – bookings and obligated capacity** – shows sold QSEC in Quarter 1 (of calendar year), peak day flow for financial year, and obligated capacity release for the Easington entry point.
12. **Isle of Grain – bookings and obligated capacity** – shows sold QSEC in Quarter 1 (of calendar year), peak day flow for financial year, and obligated capacity release for the Isle of Grain entry point.
13. **Milford Haven – bookings and obligated capacity** – shows sold QSEC in Quarter 1 (of calendar year), peak day flow for financial year, and obligated capacity release for the Milford Haven entry point.
14. **St Fergus – bookings and obligated capacity** – shows sold QSEC in Quarter 1 (of calendar year), peak day flow for financial year, and obligated capacity release for the St Fergus entry point.
15. **Bacton CAM – bookings and obligated capacity** – shows sold QSEC in Quarter 1 (of calendar year), peak day flow for financial year, and obligated capacity release for the Bacton CAM entry point.
16. **Wholesale gas prices (p/kWh/day)** – shows wholesale day-ahead prices for NBP, TTF and ZEE for the financial year data used in the model (this will be 2028/29 for a full dynamic model run).
17. **Interconnector flows (price spread vs. flows)** – shows interconnector flows versus the NBP-Euro price spread (excluding marginal transaction charges). This will be 208/29 for a full dynamic model run.

5.2. Cross subsidy test

The GTCR model also includes (as an output) a simple cross-subsidy test for the selected financial year.

Currently the model includes the following:

- Take the LRMCs (KM) for each ASEP produced by the National Grid Transportation model (which are selected for the chosen National Grid scenario (e.g. Gone Green) in the GTCR model by the model user);
- Calculate costs (by ASEP) that are compared to recovered revenue (by ASEP) in the cross-subsidy test from one of the following:
  - costs by individual ASEP = initial LRMCs (KMs) by ASEP x expansion constant x annuitisation factor; or
  - costs by individual ASEP = capacity weighted initial LRMCs (KMs) by ASEP x expansion constant x annuitisation factor.
- Calculate revenues post application of secondary adjustments (including floating tariffs, inflation adjustments, multipliers and commodity charges).
- Calculate the cost and revenue pots as a percentage of total cost and total revenue recovered from individual entry points.

The same methodology is applied to calculate a cross-subsidy test that follows the principles of the cost allocation test in the ACER Framework Guidelines.

Instead of calculating the proportions by individual entry point (ASEP), the model groups the costs and revenues into CAM and non-CAM points. Two ratios are calculated within the GTCR model:

- the numerator for the first ratio is the revenue recovered from non-CAM points (including commodity charges and any secondary adjustments);
- the denominator for the first ratio is the incremental cost recovered from non-CAM points;
- the numerator for the second ratio is the revenue recovered from CAM points (including commodity charges and any secondary adjustments); and
- the denominator for the second ratio is the incremental cost recovered from CAM points.

Using the LRMCs in the cost subsidy test means that the quantum (£m) of allowed revenue recovered from each individual ASEP will differ from the quantum (£m) of the cost driver that is used in the test. Allowed revenue reflects the historical cost of the network, whilst the cost driver used in the cross subsidy test will reflect forward looking incremental cost by ASEP as derived by the Transportation model.[38]

However, by using the LRMCs as the cost driver within the test, this means that the tests focus on the cost reflectivity of the secondary adjustments that are being considered as part of the GTCR (as opposed to the underlying cost allocation methodology[39] which would be the case if alternative cost drivers were used than those applied currently in calculating reserve prices in the NGG Transportation model).

5.3. Illustration of model outputs

In this subsection we provide an illustration of the model outputs based on three illustrative policy scenarios.

We have modelled:

- a base case, based on the current structure of NTS entry pricing (i.e. including none of the GTCR policy options, whereby capacity prices are fixed and a TO commodity charge applies to all entry flows (except storage users);
- a policy scenario (scenario 1) where a form of floating regime is applied to all system ASEPs from 2017/18, short term product discounts are reduced and existing QSEC bookings are indexed to inflation from 2017/18;
- a second policy scenario (scenario 2) where the current structure of NTS charges is applied to all system ASEPs excluding CAM-points (except for reductions in short term product discounts) and a floating regime is applied at CAM-points.
- a third policy scenario (scenario 3) using the same floating regime and price indexation assumptions as scenario 2 but with multipliers (1.2x) applied to short term capacity products relative to long term products.

Table 5.1 describes the assumptions that have been used to structure each of these illustrative model policy options. We show a selection of:

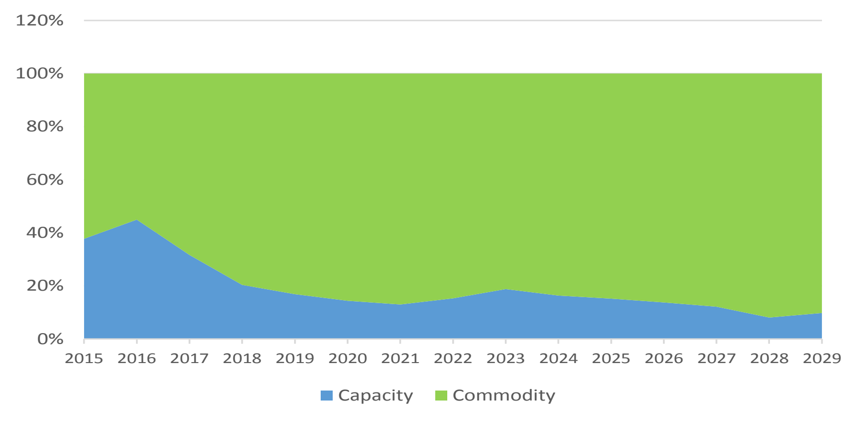
- tariff outputs from the model (including levels of TO commodity charges and capacity charges and the composition of entry charge applied at a subset of ASEPs);
- revenue recovery outputs, including the implied capacity/commodity split, revenue recovery at a subset of ASEPs and revenue recovery by user group; and
- illustrations of annual and peak day flows in the modelling and quarter one capacity bookings at a subset of ASEPs.

[38] Heavily influenced by the adopted expansion constant.
[39] Virtual Point (VP) Variant A under the ACER Framework Guidelines.

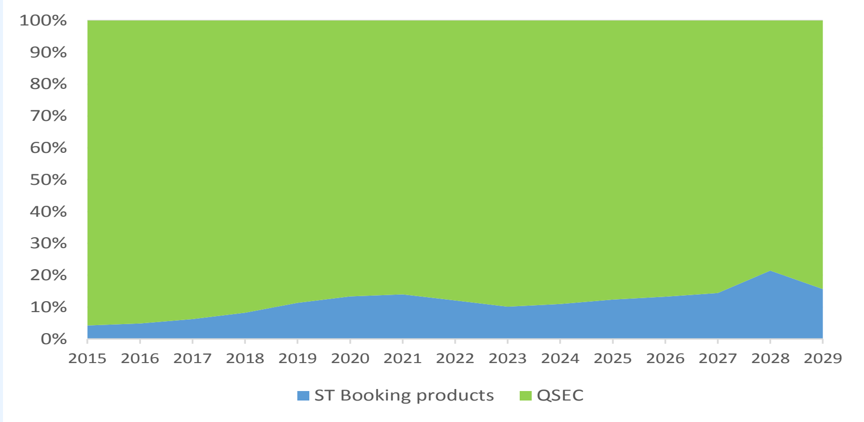
Table 5.1: Illustrative model policy scenarios

	Base case	Scenario 1	Scenario 2	Scenario 3
Description	Current charging regime – combination of capacity and commodity charges	A combination of policy options being considered by the GTCR, including changes to multipliers, inflation indexation of reserve prices and floating capacity tariffs	As per Scenario 1 but a floating capacity price regime applies only to CAM points	As per Scenario 1 but with multipliers (1.2x) applied to short term capacity products relative to long term products
Inflation indexation	N/A	Existing QSEC booking prices are indexed from start of financial year 2017/18	As per Scenario 1	As per Scenario 1 and 2
Floating capacity tariff regime	N/A	Option 9 – see annex B Fixed p/KWh/day secondary adjustment applies to all capacity products from 2017. This means the floating adjustment applies to new and existing capacity The floating adjustment is calculated after the application of multipliers to the original NTS Transportation model reserve prices The floating adjustment is assumed not to apply to storage users	Option 9 – see annex B BACTON (CAM point) tariff calculated under same principles as Scenario 1 Non-CAM ASEP tariffs are calculated under the same principles as Base Case	As per Scenario 2
Multipliers	QSEC – 1.0; MSEC – 1.0; DADSEC – 0.66; WDDSEC – 0; DISEC – 0	QSEC – 1.0; MSEC – 1.0; DADSEC – 0.66; WDDSEC – 0.66; DISEC – 0.66	As per Scenario 1	QSEC – 1.0; MSEC – 1.0; DADSEC – 1.2; WDDSEC – 1.2; DISEC – 1.2

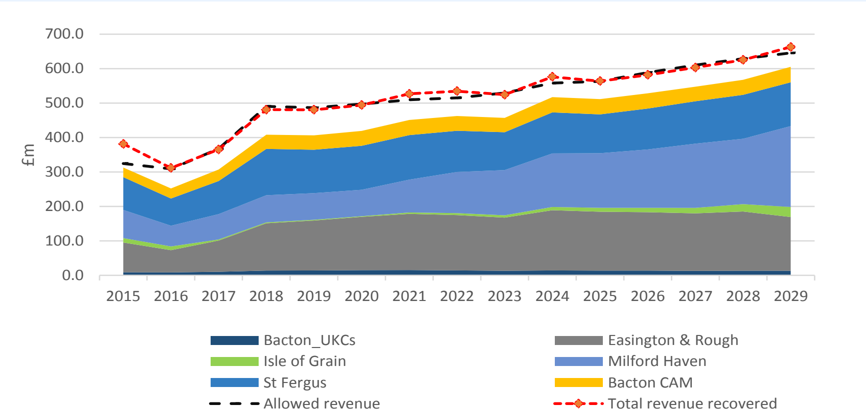
Base Case: Capacity / Commodity split in TO allowed revenue



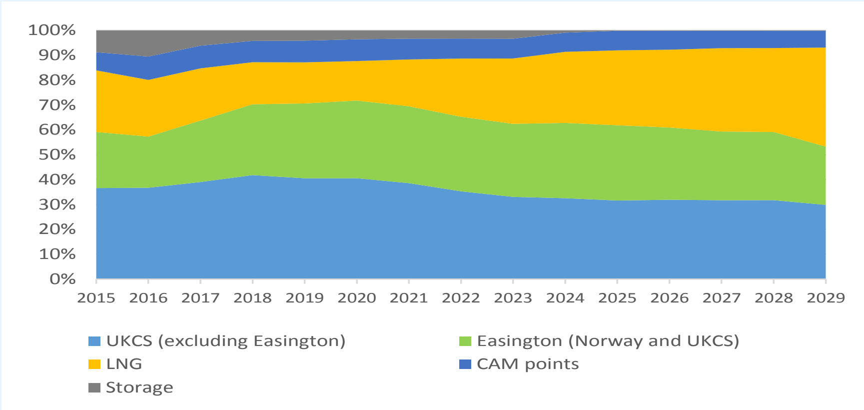
Base Case: Revenue recovery by capacity booking products



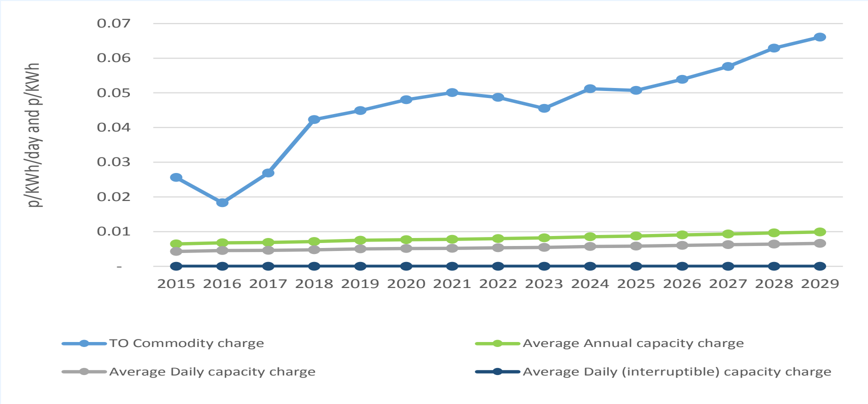
Base Case: Revenue recovery by key ASEP



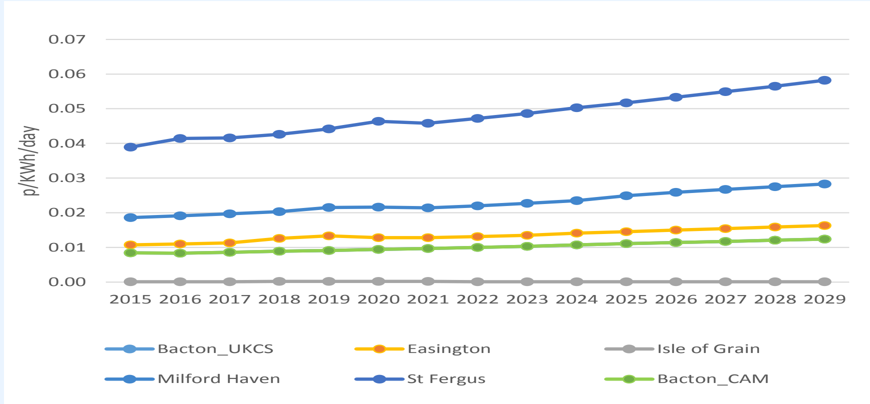
Base Case: Revenue recovery by user group



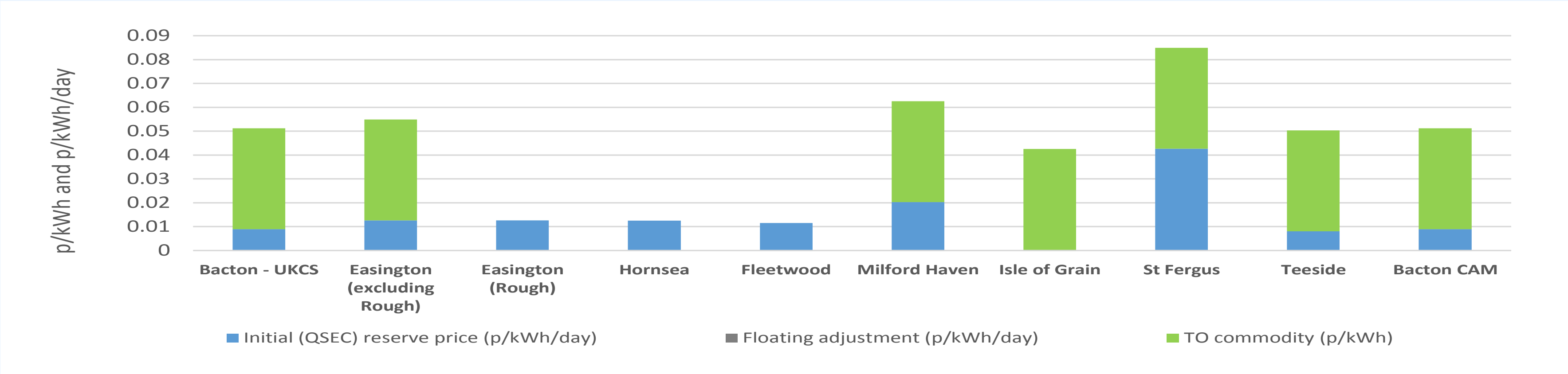
Base Case: Average NTS tariffs



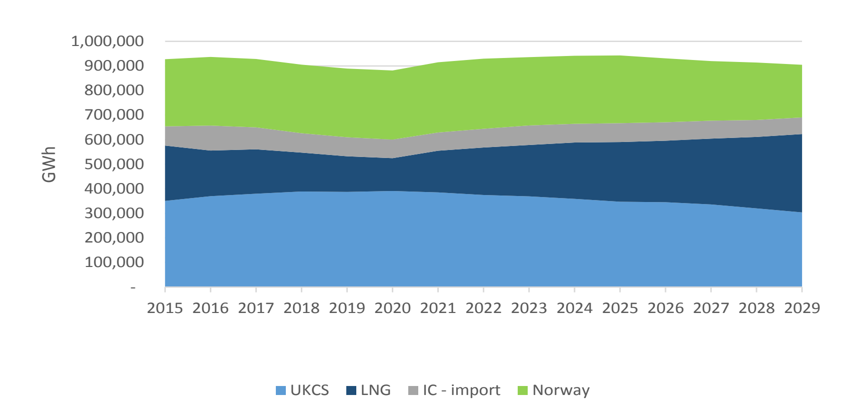
Base Case: Annual capacity charges at subset of ASEPs



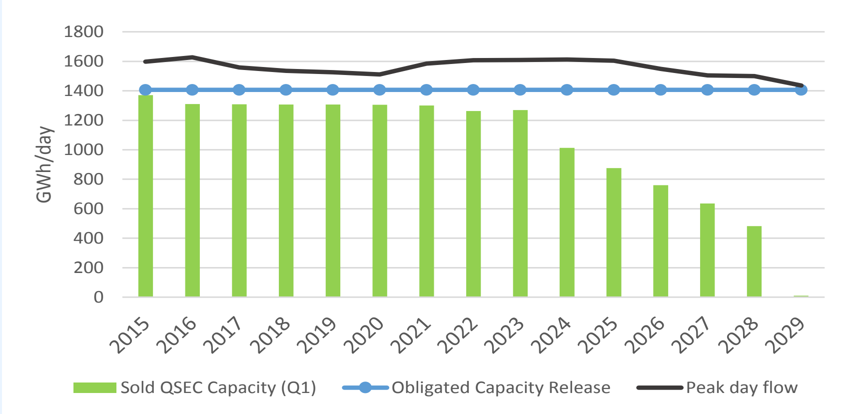
Base Case: Composition of total NTS charge at subset of ASEPs – 2017/18



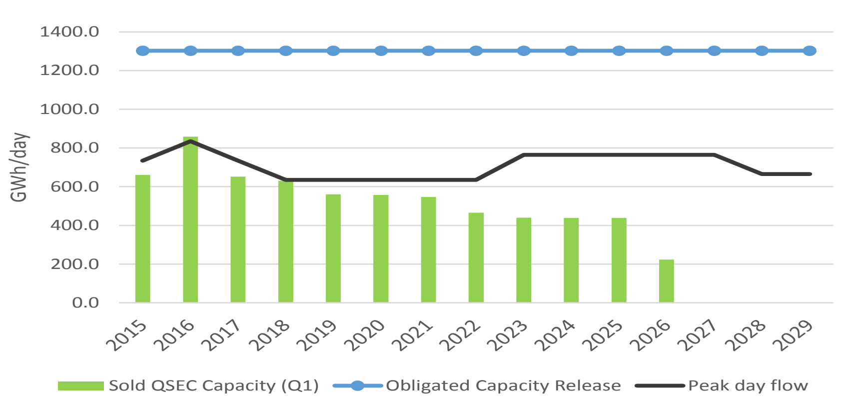
Base Case: Annual flows by supply source



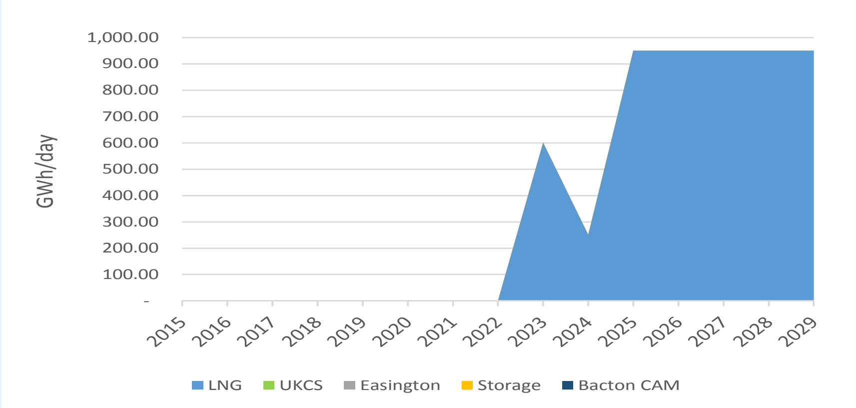
Base Case: Easington ASEP - peak flows and capacity bookings



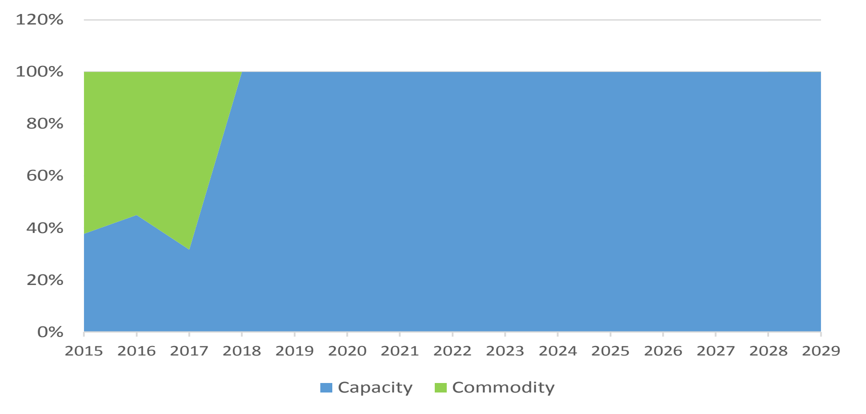
Base Case: Bacton CAM ASEP – peak flows and capacity bookings



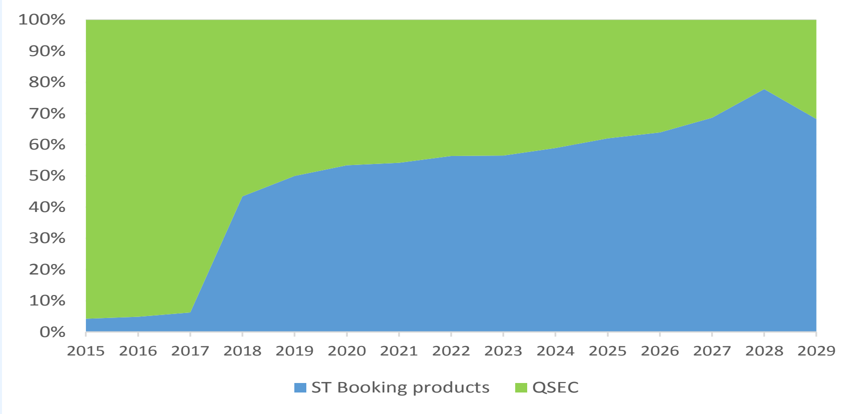
Base Case: New QSEC bookings



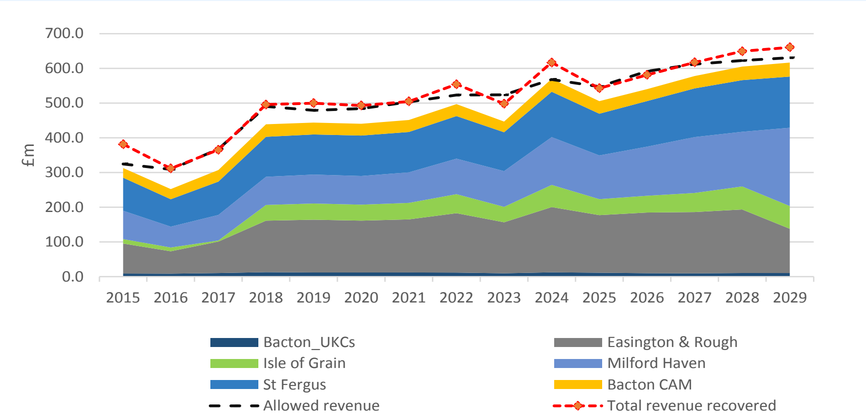
Scenario 1: Capacity / Commodity split in TO allowed revenue



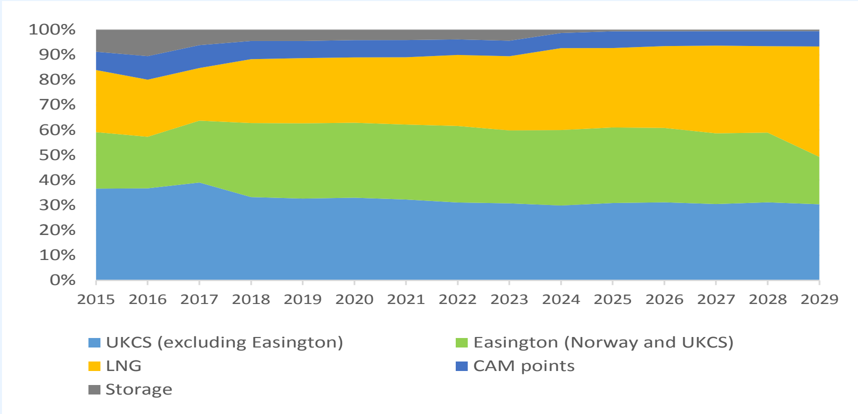
Scenario 1: Revenue recovery by capacity booking products



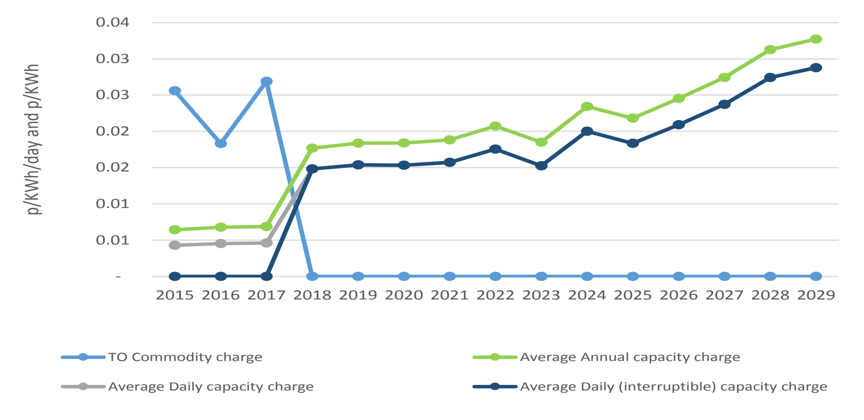
Scenario 1: Revenue recovery by key ASEP



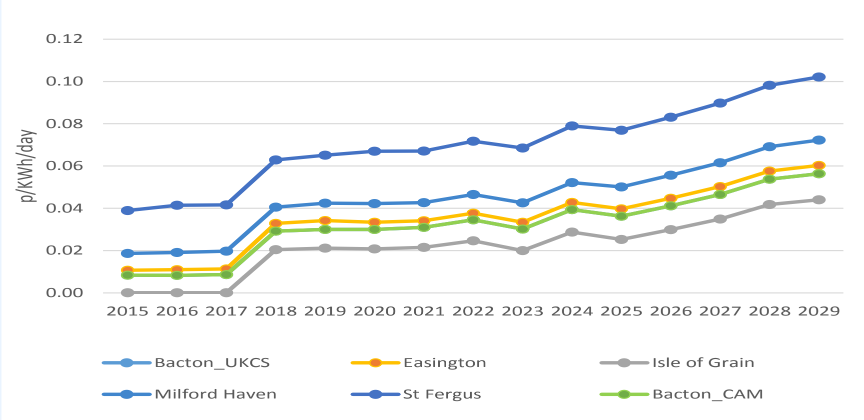
Scenario 1: Revenue recovery by user group



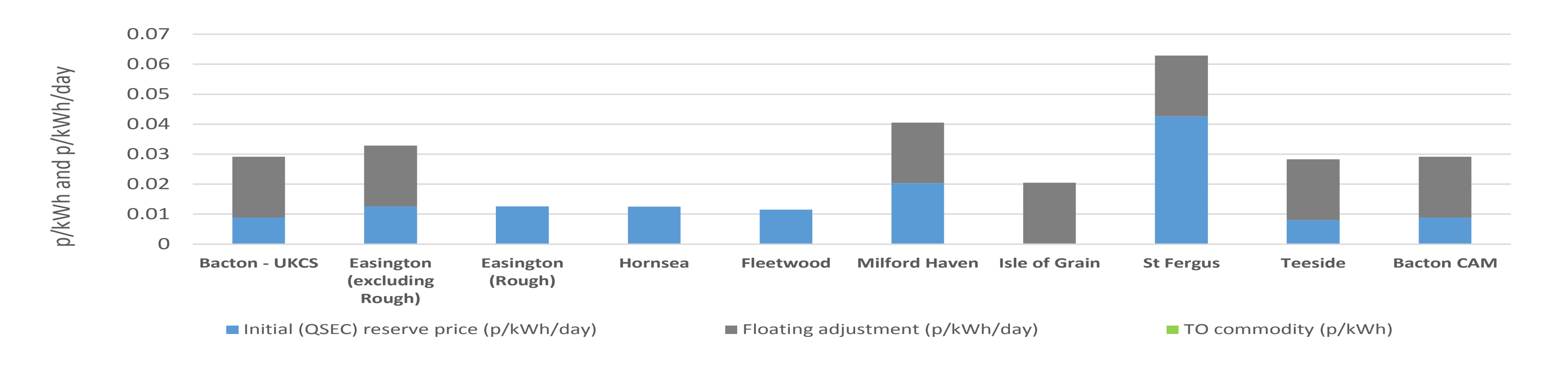
Scenario 1: Average NTS tariffs



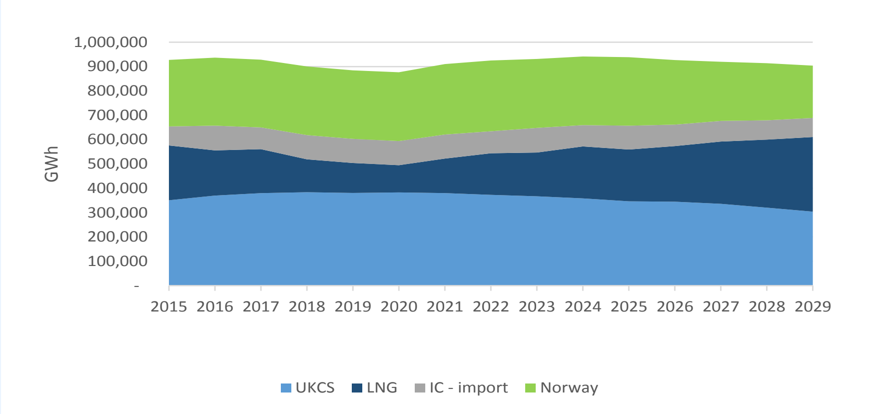
Scenario 1: Annual capacity charges at subset of ASEPs



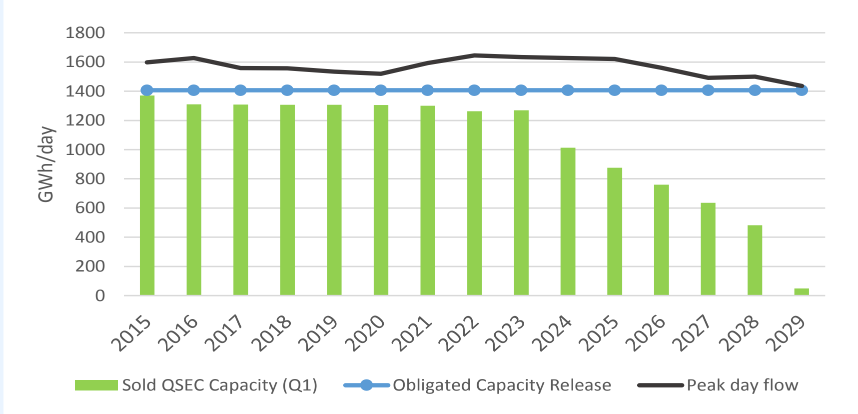
Scenario 1: Composition of total NTS charge at subset of ASEPs – 2017/18



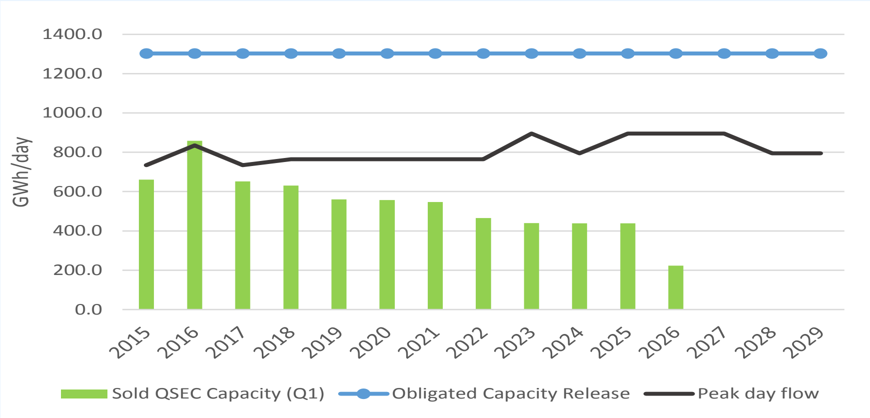
Scenario 1: Annual flows by supply source



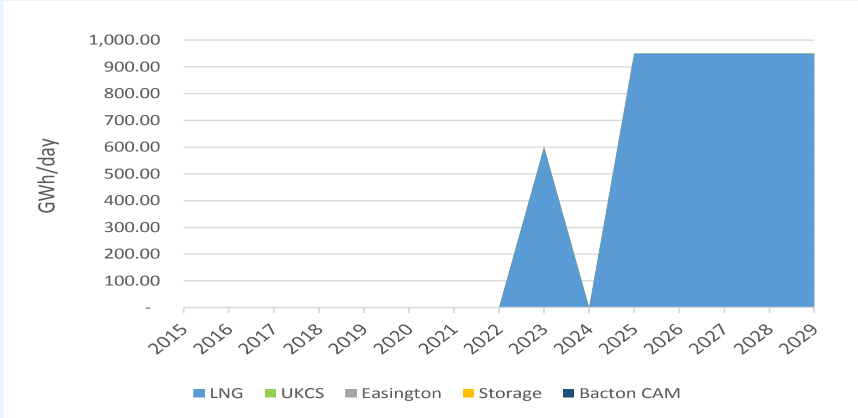
Scenario 1: Easington ASEP - peak flows and capacity bookings



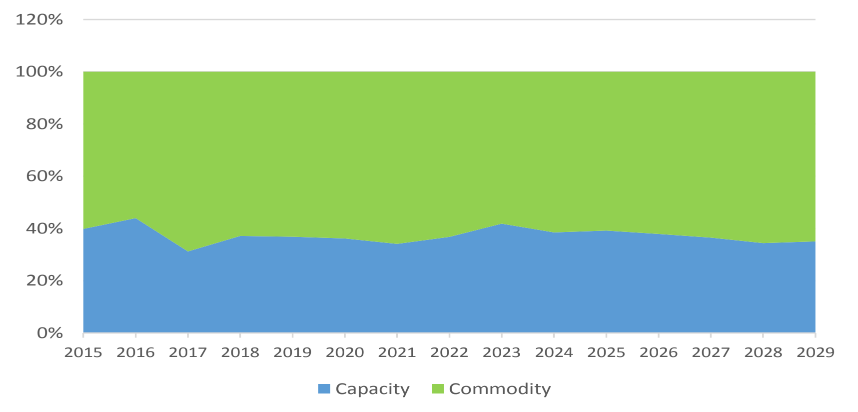
Scenario 1: Bacton CAM ASEP – peak flows and capacity bookings



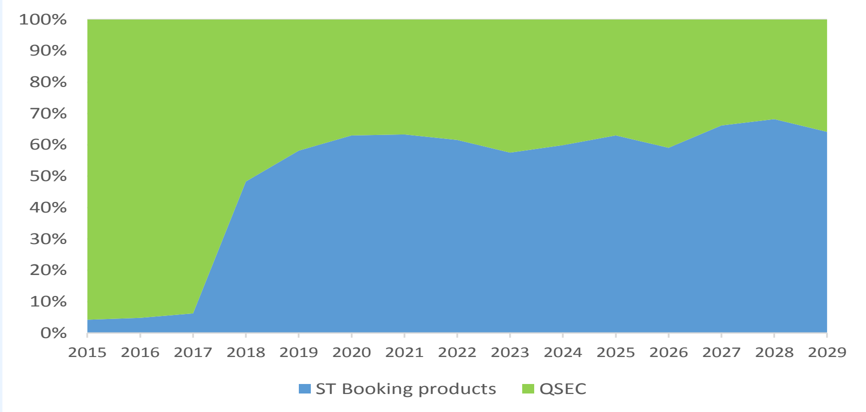
Scenario 1: New QSEC bookings



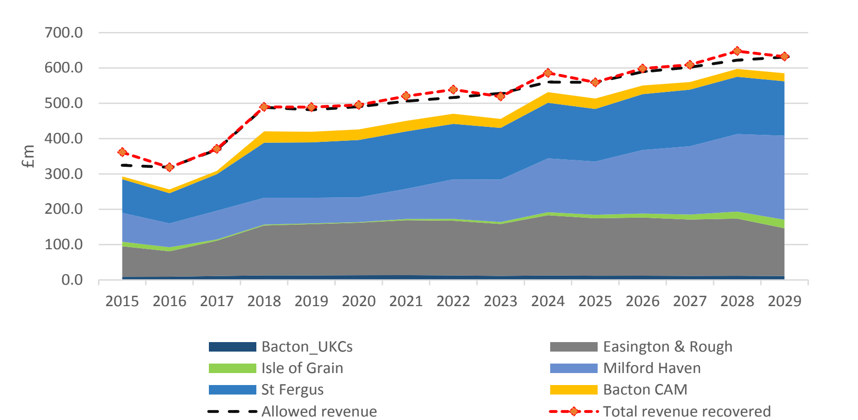
Scenario 2: Capacity / Commodity split in TO allowed revenue



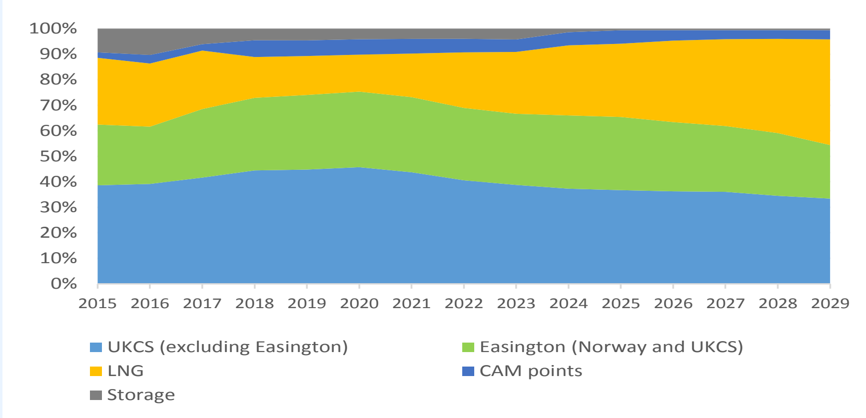
Scenario 2: Revenue recovery by capacity booking products



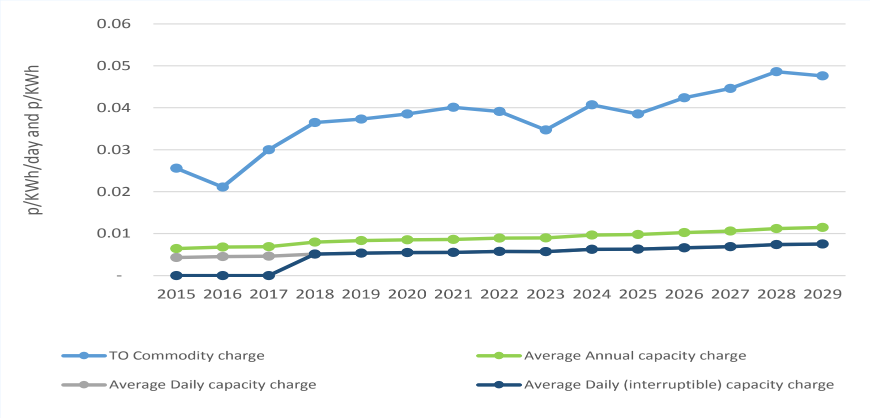
Scenario 2: Revenue recovery by key ASEP



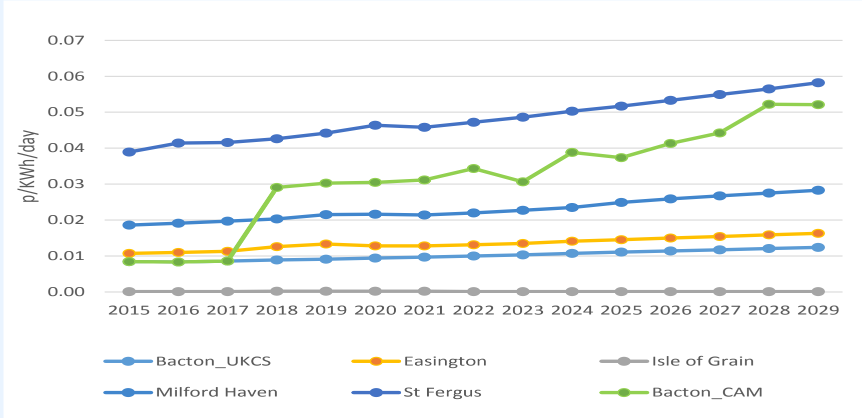
Scenario 2: Revenue recovery by user group



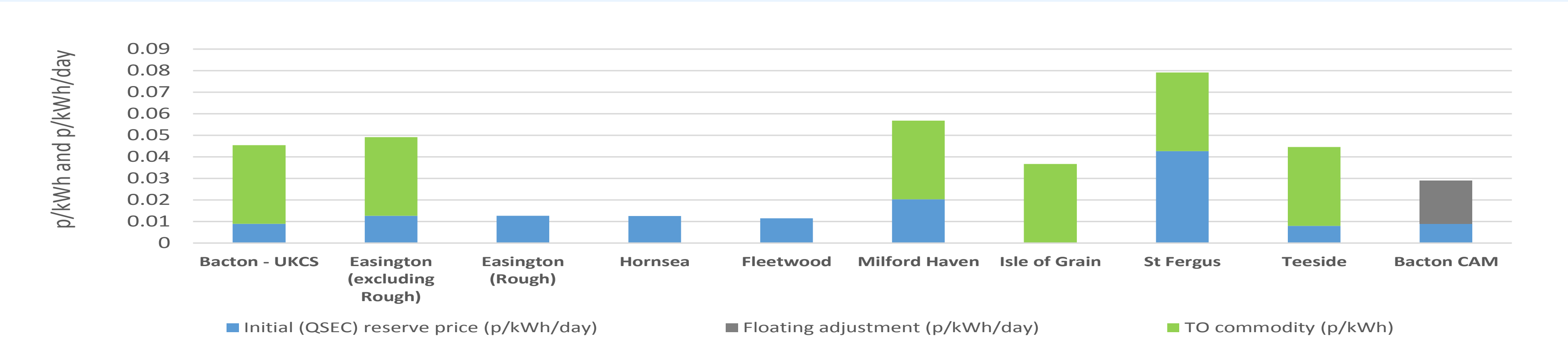
Scenario 2: Average NTS tariffs



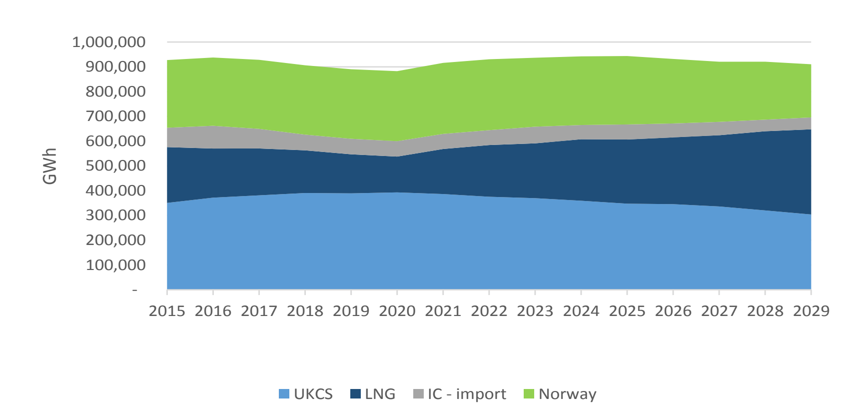
Scenario 2: Annual capacity charges at subset of ASEPs



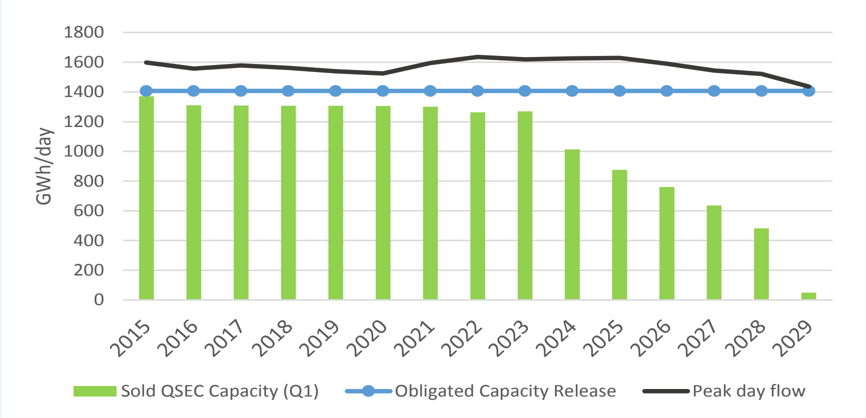
Scenario 2: Composition of total NTS charge at subset of ASEPs – 2017/18



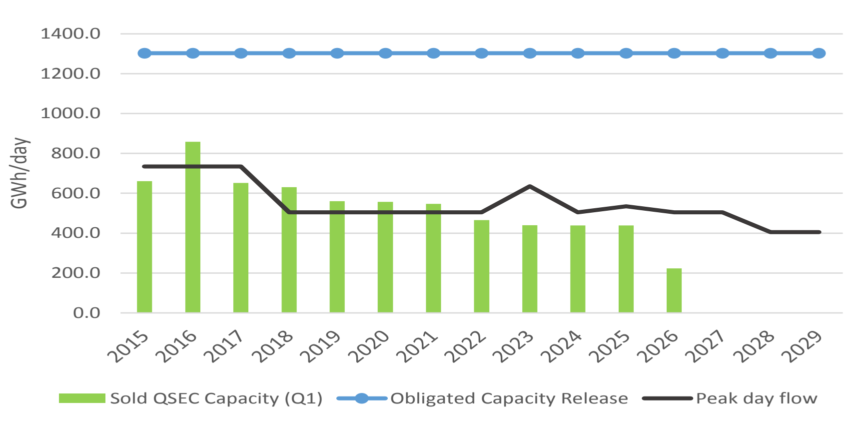
Scenario 2: Annual flows by supply source



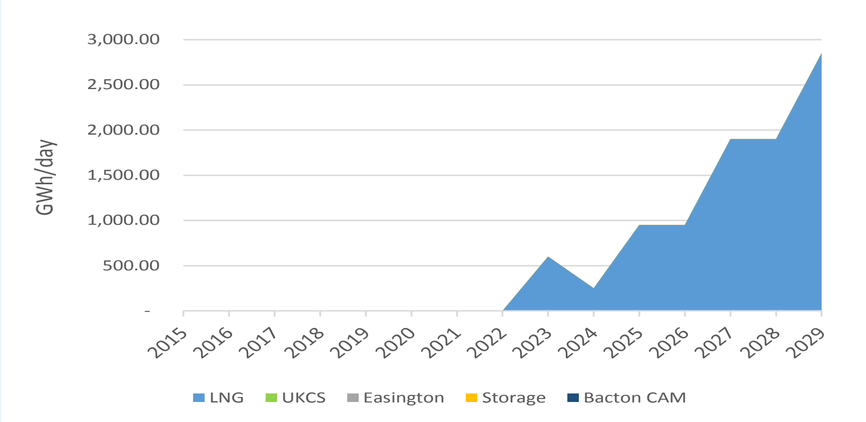
Scenario 2: Easington ASEP - peak flows and capacity bookings



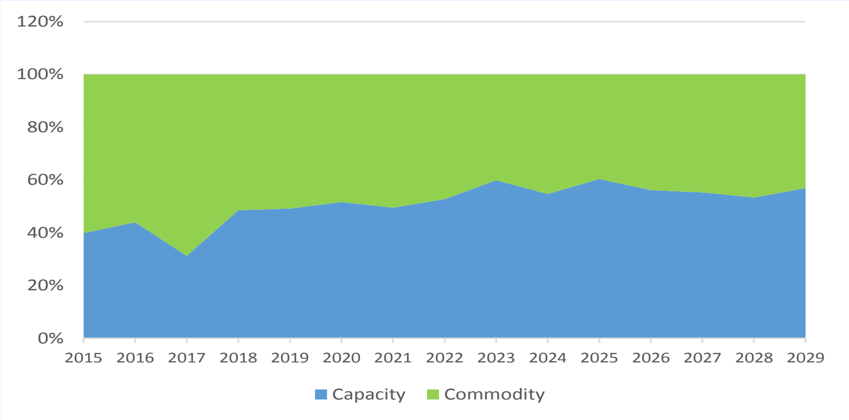
Scenario 2: Bacton CAM ASEP – peak flows and capacity bookings



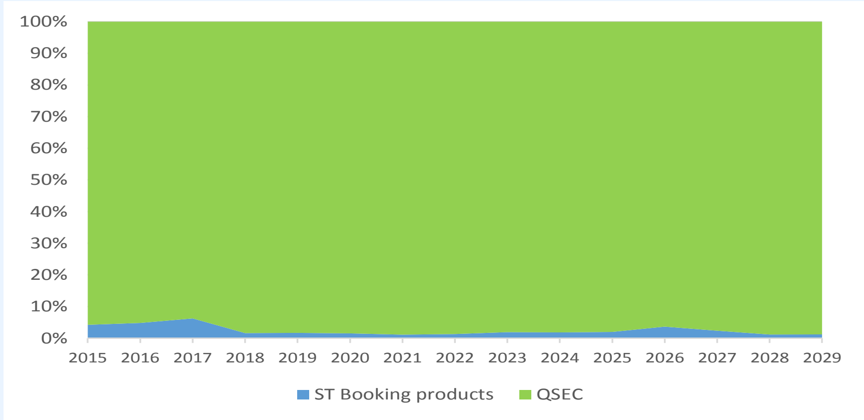
Scenario 2: New QSEC bookings



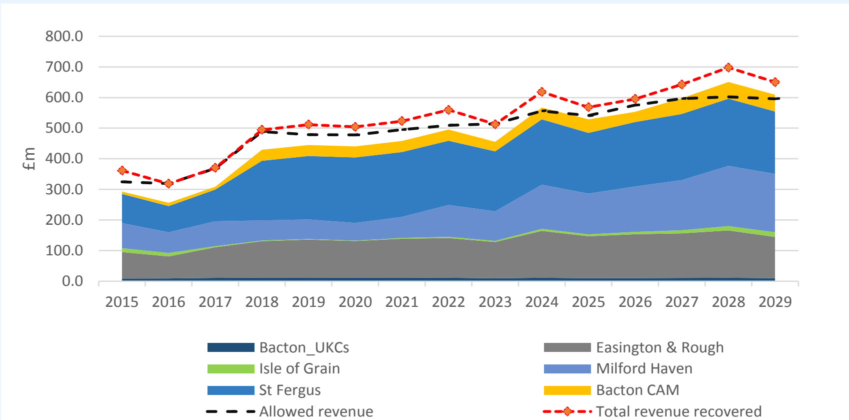
Scenario 3: Capacity / Commodity split in TO allowed revenue



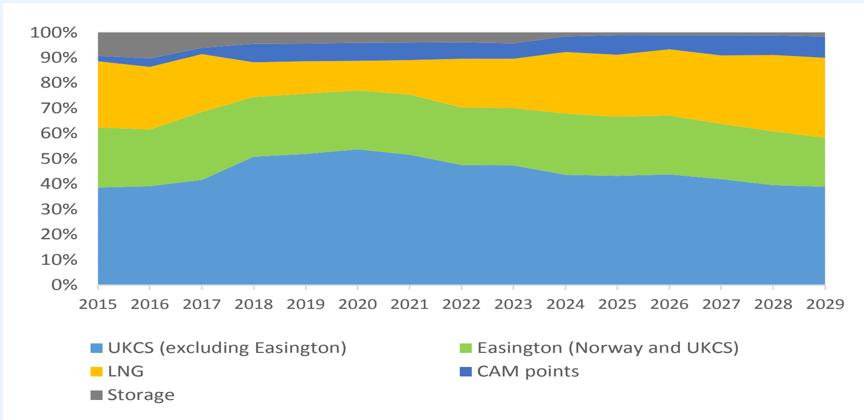
Scenario 3: Revenue recovery by capacity booking products



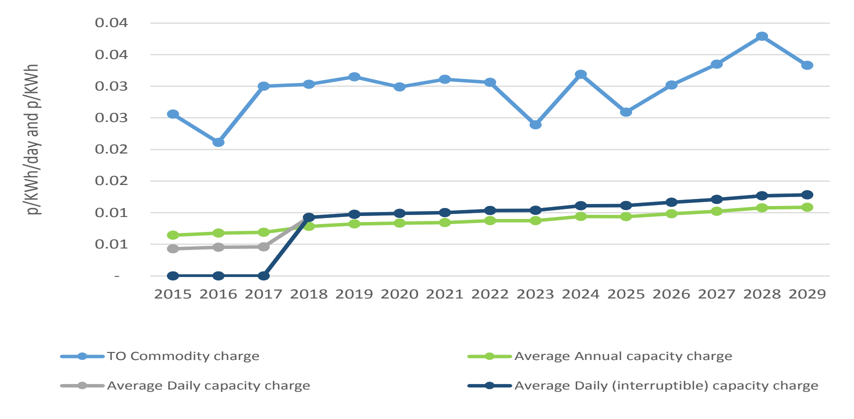
Scenario 3: Revenue recovery by key ASEP



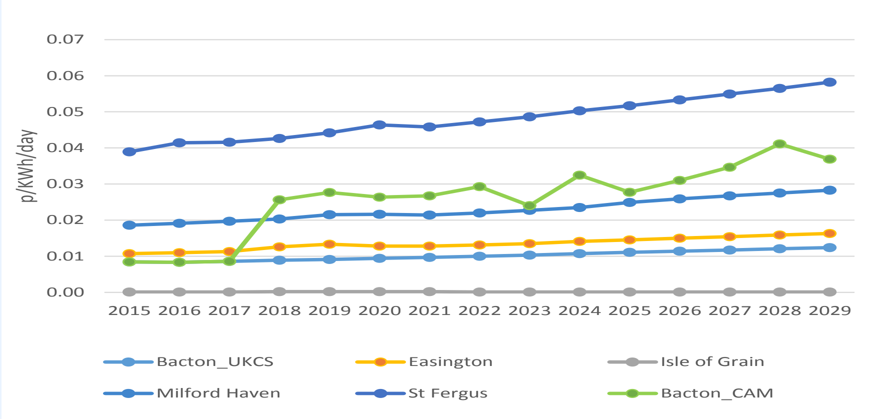
Scenario 3: Revenue recovery by user group



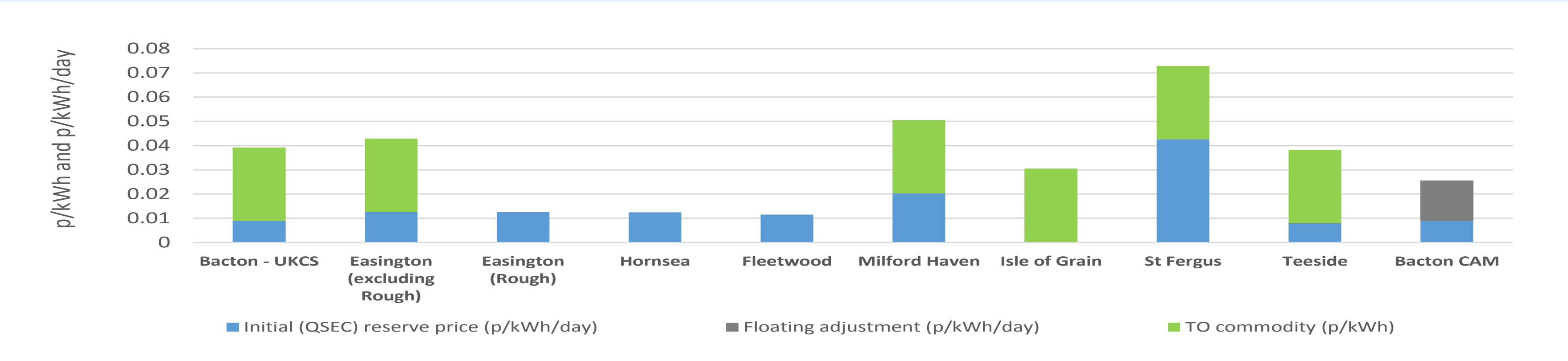
Scenario 3: Average NTS tariffs



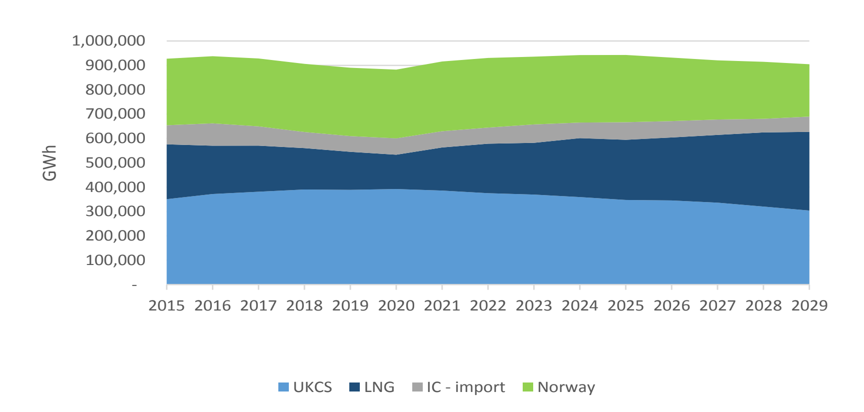
Scenario 3: Annual capacity charges at subset of ASEPs



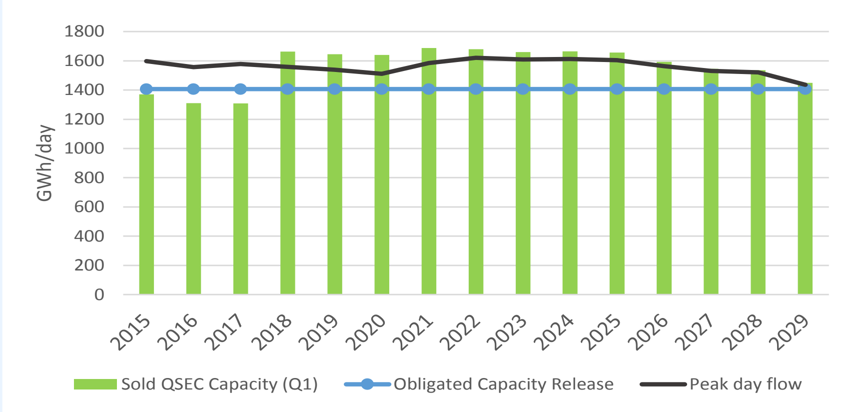
Scenario 3: Composition of total NTS charge at subset of ASEPs – 2017/18



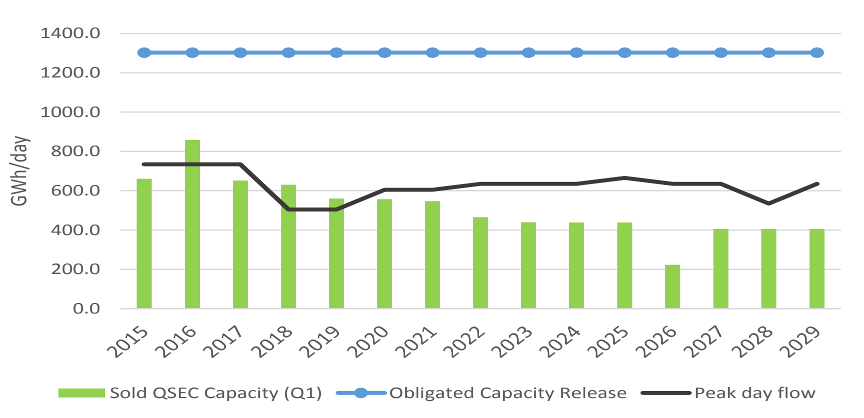
Scenario 3: Annual flows by supply source



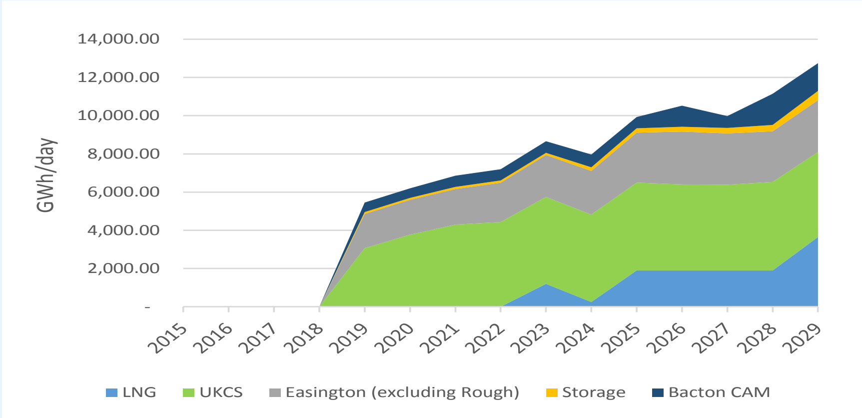
Scenario 3: Easington ASEP - peak flows and capacity bookings



Scenario 3: Bacton CAM ASEP – peak flows and capacity bookings



Scenario 3: New QSEC bookings



ANNEX A PRICE RESPONSIVENESS OF DEMAND FOR NTS CAPACITY

In this annex we consider what is meant by price responsiveness of demand for NTS entry capacity and its primary determinants. This forms the basis for the assumptions used in developing the GTCR model framework.

A.1. Determinants of price responsiveness of demand

The demand for gas transmission capacity is a derived demand: users require NTS capacity to flow to GB's wholesale gas market (or that of a neighbouring country where there is cross-border interconnector capacity).

Users' price responsiveness is, therefore, closely interlinked with wholesale market structure, the expected position of supply sources in the merit order and supply profiling / flow requirements given their reaction to, or role in setting, wholesale prices. The demand for NTS capacity may also be influenced by opportunities for trading in other markets in response to profitable trading opportunities (flow/dispatch optionality).

Consistent with economic theory, network users' willingness to make capacity commitments can also be expected to reflect their evaluation of NTS capacity scarcity, the extent to which they value capacity certainty (given supply arrangements) or anticipate short term capacity constraints and the prevailing level of discounts (or premia) for short term capacity. This valuation will be driven in part by their contracts with customers. The types of wholesale trading opportunities exploited by individual supply sources may also influence how particular users of the NTS respond to changes in NTS prices.

There are, therefore, a number of possible determinants of price responsiveness of demand for NTS capacity as detailed in the subsections below.

A.1.1. Wholesale gas market structure

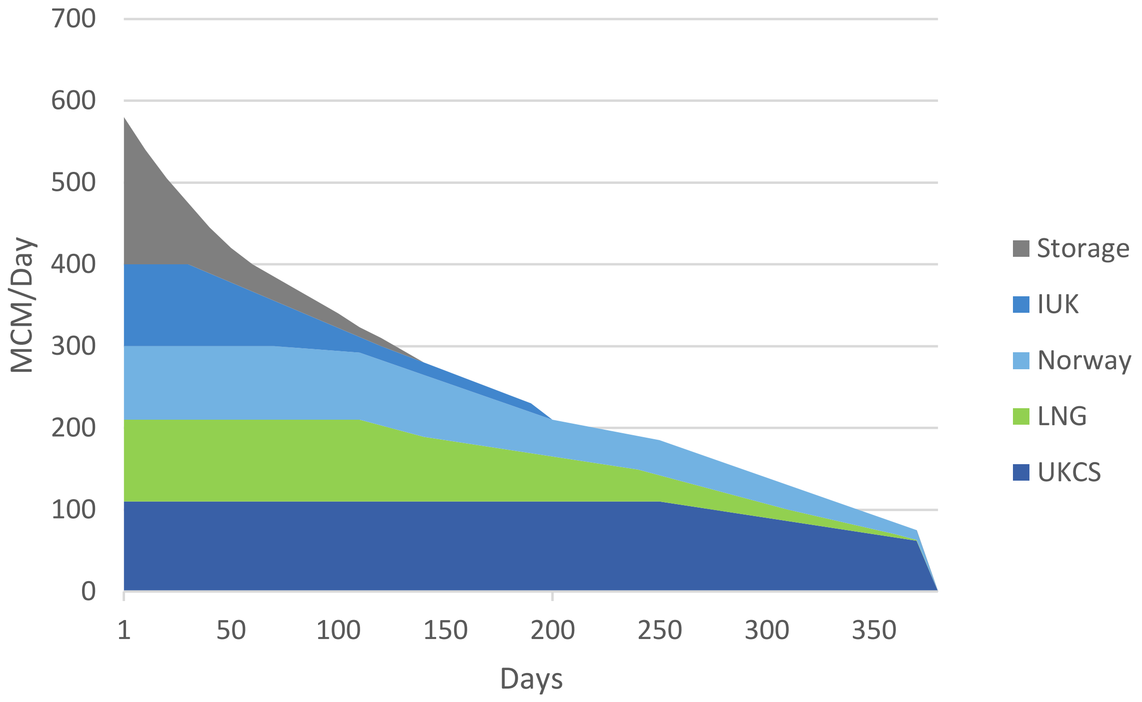
The structure of supply to the GB market has a major influence on the structure of demand for NTS capacity.

The GB wholesale market currently has many different sources of supply, including beach supplies; interconnectors, LNG importation; and various forms of short, mid and long term storage. As illustrated in Figure A.1 below, these sources are expected to be used at different times of the year as determined by the shape of the GB gas load duration curve.

For example, on peak days, more discretionary supplies – e.g. LNG spot or interconnector pipeline – can be required but these supplies can also be flexible to flow to other markets. Storage is another source available on peak days, but the discretion here is typically more temporal rather than supplying an alternative geographical market. At other times of the year demand may be met with less discretionary supplies – e.g. baseload contracted LNG imports or beach supplies from dry or (especially) associated gas fields.

The concept of discretionary and non-discretionary sources of supply – the former having flow optionality – is an important feature of the structure of demand for NTS capacity and how that demand structure responds to changes in NTS tariff structures. As the structure of the GB market changes, the mix of discretionary and non-discretionary supplies will change, as will the structure of demand for NTS capacity.

Figure A.1: Illustrative GB load duration curve



Source: CEPA and TPA

A.1.2. Scarcity of NTS capacity

The scarcity of entry capacity for the NTS in general and for individual ASEPs, will also be a determinant of price responsiveness of demand. It may also impact on incentives for long term and short term booking strategies. The possibility of entry capacity constraints can introduce opportunity costs for shippers and gas suppliers, including a loss of sale of gas at NBP, possible exposure to NTS imbalance charges and opportunity costs in related commodity markets (e.g. upstream oil production).

The value of a loss of sale, for example, is likely to be particularly important when capacity is constrained, especially at an important ASEP that can influence the NBP price.

The need to acquire capacity at that ASEP (rather than not flowing gas) will be a function of any contractual commitment (or own gas production) that can only be delivered via that ASEP. Many contractual commitments in the GB market today can be met at the NBP and do not dictate a particular route for gas supply, and shipper energy balancing exposure is also calculated nationally (again, this is where the differentiation between discretionary and non-discretionary sources of supply can become important). However, field specific sources such as an associated gas supply may require the buying shippers to take gas at a particular ASEP (typically St. Fergus) in order, for example, to maintain upstream oil production.

Although the current outlook at most ASEPs is for adequate entry capacity, barring unforeseen operational incidents or (more predictable) longer term substitution of obligated capacity between terminals by National Grid, the perceived risk (and value) of a capacity constraint at an ASEP – given the potential opportunity cost of the value of the sales forgone should NTS capacity not be available – can still be expected to influence the structure of demand for different forms (e.g. long and short term) capacity[40] and how responsive different users entry booking strategies for the NTS will be to the price of alternative capacity products.

As a general observation, NTS capacity in total is relatively inexpensive in relation to the sunk costs upstream and downstream of the onshore transmission system, and NTS entry capacity is hence a relatively low proportion of total gas value. Therefore, the risk of under purchasing entry capacity, even in the context of adequate supply, should in theory influence user decision making. The value of a particular booking strategy (for a given structure of NTS prices) must, therefore, be considered in the wider context of the value of transportation capacity within the wholesale gas market.

A.1.3. Role of transaction costs in cross-border flows

The GB market is expected to increasingly be supplied by imported gas as production from the UK continental shelf declines.

A number of possible importation supply sources may be committed to supplying (importing) to the GB market (e.g. through long term contractual commitments) and have no or limited option to flow elsewhere (i.e. to other markets). However, other sources of import supply will have clear flow optionality (e.g. certain forms of LNG and spot interconnector trades).

Gas that has flow optionality will be traded on the basis of the relative value of the supplies in the GB and neighbouring / international gas markets. For these supply sources, the price responsiveness of demand for NTS capacity will be determined by how NTS charges affect the relative value of dispatch to GB as compared to neighbouring markets. This may be influenced by a number of factors including:

- how particular forms of NTS entry tariff (capacity vs. commodity) are treated in trading decisions (e.g. sunk cost or a commoditised cost);
- whether on the day a particular source of supply can expect to influence the wholesale spot price at the margin; and

[40] Subject to decent sized multipliers on Short Term capacity.

- whether short term flow optionality is influenced by other trading factors than simply spot prices.[41]

Central concepts when considering the price responsiveness of demand for NTS capacity for importation supplies are, therefore, the differentiation between:

- largely committed (e.g. Norway);
- non-committed (e.g. interconnector) supplies; and
- the price formation processes which apply in GB and neighbouring markets which affect cross-border dispatch decisions.

The latter requires consideration of the supply and demand fundamentals of NBP and neighbouring European markets, influenced by the development of hub pricing in Europe, and how different forms of NTS charge (and changes in transaction costs and trading arrangements in neighbouring markets) may affect dispatch decisions.

Across hubs, the price of gas, which is a homogenous good, should in theory tend towards uniformity, (allowances being made for transportation and other transaction costs), only in the absence of regulatory distortions, physical barriers to trade and other barriers that prevent competition and arbitrage activities.

In a competitive context, arbitrage across the hubs should eliminate price differences apart from those due to transaction costs (such as NTS entry pricing and other transportation costs). This is often referred to by economists as the “relative law of one price” and the area within which the price of the homogenous good equalises, net of transaction costs, is referred to as a “geographic market”.[42]

We describe the assumptions and approach applied within the GTCR for modelling the responsiveness of cross-border flows to changes in NTS charges as part of Annex C.

A.1.4. Role of transaction costs in storage flows

The responsiveness of storage flows to NTS price changes (and therefore the demand for NTS capacity) may differ by type of storage facility.

For long duration storage (e.g. Rough) demand for entry capacity might be expected to be inelastic given the relatively high upstream investment in the storage facility, although an operator may be concerned that bundling full price LT capacity might erode underlying storage value from a customer perspective, especially where the customer perceives little risk of relying on (cheap) ST capacity.

In contrast, from our engagement with the GTCR Technical Working Group, we understand it is feasible that MRS storage could be more responsive to changes in NTS network charges

[41] For example, flows in summer may be influenced by expected trading opportunities in winter, available storage capacity and national supply obligations.
[42] Petrovich, P (2013): ‘European gas hubs: how strong is price correlation’

because they can seek to exploit smaller and shorter term arbitrage opportunities. Currently storage is exempt from commodity charges which can make it profitable to cycle in many circumstances and it is possible that a movement away from this (e.g. by introduction of a floating capacity tariff regime applied to all ASEPs in place of the current commodity charge) could diminish such opportunities. This may influence the approach taken to booking NTS capacity as well as the underlying level and frequency of storage flows themselves.

A.2. Application in the GTCR model

These determinants of the price responsiveness of demand for NTS capacity have been accommodated in the GTCR model as follows:

- interconnector and Norway (arbitrage) import and export flows are determined having accounted for the impact of changes in transaction costs under modelled NTS entry charge policy scenarios;
- as described in the main report, new entry bookings are determined in the model with reference to the expected value (opportunity cost) of NTS capacity given the probability of a constraint at an ASEP (scarcity of capacity); and
- entry bookings are determined for each year in the model based on modelled flows to each ASEP and therefore the structure of demand for NTS capacity (under a set of prices) changes with projected changes in GB wholesale market structure.

For simplicity purposes, the GTCR model does not consider flow responsiveness to changes in NTS prices for sources of supply (such as MRS or spot LNG) which at the margins could be affected by changes in the structure of charges. The model, however, does forecast how these sources of supply (by ASEP) could change their booking strategy for a given daily NTS flow requirement (by ASEP). As described in Section 3, this is a potential refinement to the model that could be considered by Ofgem.

In Table A.1 overleaf, we describe some of the dispatch features of the gas supply sources we have considered in the price responsiveness modelling, their swing capability, flow optionality and potential opportunity costs in the event of capacity scarcity/constraints at an NTS entry point. This analysis has also formed the basis for modelling the expected value of a constraint at individual ASEPs by GB supply source (see Annex E).

Table A.1: Supply sources and dispatch decisions

Supply source	Flow optionality?	Source of swing supply?	Expected NTS capacity price responsiveness of demand?	Flow NTS price responsiveness and opportunity cost considerations in the event of capacity scarcity at a given system entry point
Beach supplies - dry gas field	Low Option exists for buyer of Take of Pay contract to reduce offtake (to zero) especially when prices are low in summer	✓	Low	Low flow responsiveness to changes in NTS prices in the wider context of the gas value chain. However, in considering the form of capacity product that is booked, a shipper *as buyer* will be considering the costs of the loss of the gas sale from this supply source. A shipper as *owner* of the gas field will be considering the potential loss of revenue net of avoided marginal production costs on gas. Small quantities of liquids production (condensate gas) may also involve an additional opportunity cost in the event of a constraint at an NTS ASEP.
	Dispatch features: Traditionally has been a relatively high swing (low load factor) source of supply under long term take or pay contracts with lengthy plateau period – shipper buyer can nominate up to maximum daily quantity with possibility of excess gas availability at a premium. Declining peak supplies have meant that the UK can no longer meet winter demand without the help of other supply sources.			
Beach supplies - associated gas field	✗	✗	Low	Low flow responsiveness to changes in NTS prices in the wider context of the gas value chain. In booking capacity, the shipper as *buyer* is typically contractually obliged to accept the producer's nomination for an associated gas field and may therefore be expected to consider the costs of not being able to meet that contractual commitment. The shipper who is an owner of an associated gas field will have a high preference for maintained gas flow, since highly valuable oil and liquids production may be at risk. This may be a key opportunity cost consideration.

Supply source	Flow optionality?	Source of swing supply?	Expected NTS capacity price responsiveness of demand?	Flow NTS price responsiveness and opportunity cost considerations in the event of capacity scarcity at a given system entry point
	Dispatch features: Gas produced as a by-product of oil. Traditionally sold at a modest discount under a seller's nomination contract where the buyer has a daily obligation to take delivery so as to protect the more valuable oil production (in the absence of flaring rights). Typically sold as "flat gas" at standard NBP prices, but ultimately (in extremis) still a distress product that needs assured entry capacity (or will pay a premium in a constrained capacity market to ensure continued oil flow).			
LNG importation - contracted or spot	✓	✓	Low to medium	Spot LNG flows may (at the margin) in certain circumstances be affected by differentials in transaction costs (such as network charges) between traded European markets, but for simplicity purposes we assume this is not the case. In booking capacity, the expected opportunity cost of a constraint at an ASEP may be valued at the loss of full day revenue based on the upstream profit margin achieved by the LNG supply on the wholesale price at the ASEP. In reality it may be possible for this loss to be mitigated due to the storage facility optionality inherent in most LNG importation facilities. As relatively new terminals, LNG related ASEPs[43] will have been required to meet user commitment test by booking sufficient long term (QSEC) capacity to underwrite at least 50 per cent of system reinforcement costs[44] (hence, again potential for low NTS price responsiveness of demand). However, a booking decision may need to be made in future years when these existing bookings fall away.
	Dispatch features: Typically base-load supply which may be subject to long term contractual commitment to another party (at the terminal or NBP) or sold forward/spot at NBP by the operator (even where not contracted it is likely that supply chain logistics and producer strategy mitigate in favour of a substantial level of "base load" supply). However, spot LNG supplies as			

[43] e.g. Milford Haven and Isle of Grain.

[44] Which can for example be achieved by booking 100% for winter QSECs and zero for summer QSECs.

Supply source	Flow optionality?	Source of swing supply?	Expected NTS capacity price responsiveness of demand?	Flow NTS price responsiveness and opportunity cost considerations in the event of capacity scarcity at a given system entry point
	swing source to GB market can mean that LNG supplies have flow optionality to neighbouring markets in response to wholesale (and therefore potentially NTS network charge) price signals.			
Interconnector – arbitrage	✓	✓	Medium to high	Flows are responsive to changing NTS prices as compared to other transaction costs involved in market arbitrage. In booking capacity, the expected opportunity cost of a constraint at an ASEP may be valued at the loss of full day revenue based on the expected profit margin achieved from an arbitrage trade on a given gas day.
	Dispatch features: Shippers using an arbitrage interconnector (such as IUK) are continually comparing the relative merits of export or import in both forward and spot markets, net of the differences in transportation costs. Long term supply contracts may mean that interconnector capacity may not be used to full arbitrage potential.			
Interconnector – committed	✗	✗	Low	
	Dispatch features: Typically high load factor (low swing). Supply dispatch reflects long term contractual commitments that may influence the incentive to use the interconnector for arbitrage purposes even where price differentials would suggest there is an incentive to enter into arbitrage trade.			
Storage – LRS	✓	✓	Low	Low flow responsiveness to changes in NTS prices in the wider context of the LRS trade. In booking capacity, the expected opportunity cost of a constraint at an ASEP may be valued at the loss of revenue based on the profit margin achieved by a Q2/Q3 vs. Q1 (summer/ winter) arbitrage trade.
	Dispatch features: Users of LRS capacity (such as storage facilities at Rough) typically look to exploit a seasonal spread in prices between the winter and summer months. This is initially achieved by an "intrinsic trading strategy" whereby the storage capacity owner will seek to "lock in" price spreads at the start of the year by entering into forward contracts and setting an			

Supply source	Flow optionality?	Source of swing supply?	Expected NTS capacity price responsiveness of demand?	Flow NTS price responsiveness and opportunity cost considerations in the event of capacity scarcity at a given system entry point
	injection and withdrawal plan for delivery against those contracts. Further "rolling intrinsic" and extrinsic value can then be achieved by optimising withdrawals over the trading period.			
Storage – MRS	✓	✓	Medium	Potential flow responsiveness to changes in NTS prices in the context of the MRS trade. For simplicity purposes, the model assumes no flow responsiveness. In booking capacity, the expected opportunity cost of a constraint at an ASEP may be valued at a multiple of the loss of revenue based on the profit margin achieved by a Q2/Q3 vs. Q1 (summer/ winter) arbitrage trade, to reflect the extra (extrinsic) value which can be achieved by an MRS compared to LRS facility.
	Dispatch features: For MRS and SRS facilities, the holders of the storage capacity in the GB market can seek to exploit shorter term arbitrage opportunities than LRS through trading strategies that are more aimed at exploiting the volatility in daily or weekly vs. weekend prices. This can increase profits significantly from the intrinsic value of storage trading (capturing the extrinsic value), but involves much greater trading uncertainty.			

Source: CEPA and TPA

ANNEX B CAPACITY CHARGE REGIMES

Option 1

Design element	
Does the floating adjustment involve an adjustment to the reserve prices?	No floating tariff
What measure of capacity is used to calculate the size of the floating adjustment?	N/A
How is the floating adjustment calculated with known multipliers for different capacity products?	No floating adjustment – multipliers are applied to current methodology derived 50:50 adjusted reserve prices

Option description:

Based on current methodology.

Capacity charges for new bookings are based on the 50:50 adjusted reserve prices from the Transportation model.

Multipliers are applied to these reserve prices to arrive at prices for individual capacity products.

Option 2

Design element	
Does the floating adjustment involve an adjustment to the reserve prices?	Yes – a km adjustment is applied to the LRMCs
What measure of capacity is used to calculate the size of the floating adjustment?	Forecast peak capacity
How is the floating adjustment calculated with known multipliers for different capacity products?	Multipliers applied after the floating adjustment

Option description:

A fixed floating adjustment is applied (KM) to LRMC KMs for each entry point to recover allowed revenue assuming annual bookings at forecast peak capacity.

This takes no account of existing bookings – i.e. every user at an ASEP is assumed to be charged the same prices as calculated by the methodology and doesn't account for ASEP users who may have secured a lower price in previous auction rounds.

The floating adjustment is also applied before multipliers and can therefore be expected to result in an under-recovery of revenue.

Option 3

Design element	
Does the floating adjustment involve an adjustment to the reserve prices?	Yes – a £/kWh adjustment is applied
What measure of capacity is used to calculate the size of the floating adjustment?	Forecast peak capacity
How is the floating adjustment calculated with known multipliers for different capacity products?	Multipliers applied after the floating adjustment

Option description:

Apply a p/KWh/day adjustment to the reserve prices for each entry point to recover allowed revenue assuming annual bookings at forecast peak capacity.

This takes no account of existing bookings – i.e. every user at an ASEP is assumed to be charged the same prices as calculated by the methodology and doesn't account for ASEP users who may have secured a lower price in previous auction rounds.

The floating adjustment is also applied before multipliers and can therefore be expected to result in an under-recovery of revenue.

Option 4

Design element	
Does the floating adjustment involve an adjustment to the reserve prices?	Yes – a km adjustment and second p/kWh adjustment
What measure of capacity is used to calculate the size of the floating adjustment?	Forecast and booked capacity
How is the floating adjustment calculated with known multipliers for different capacity products?	Multipliers applied after the floating adjustment

Option description:

The same steps are followed as per Option 2. A second secondary adjustment is then also made to the tariffs to recover target allowed revenue given forecast booked levels of capacity by ASEP.

This methodology (whilst taking account of booked capacity) does not take account of the terms on which existing bookings (e.g. tariff levels) are based. It assumes all users pay the current year reserve prices with the two staged floating adjustment.

The floating adjustment is also applied before multipliers and can therefore be expected to result in an under-recovery of revenue.

Option 5

Design element	
Does the floating adjustment involve an adjustment to the reserve prices?	Yes – a two staged £/kWh adjustment is applied
What measure of capacity is used to calculate the size of the floating adjustment?	Forecast and booked capacity
How is the floating adjustment calculated with known multipliers for different capacity products?	Multipliers applied after the floating adjustment

Option description:

As per Option 3, but a second secondary adjustment is also made to the tariffs to recover target allowed revenue applying booked capacity in the floating adjustment calculations.

This methodology (whilst taking account of booked capacity) does not take account of the terms on which existing bookings (e.g. tariff levels) are based. It assumes all users pay the current year reserve prices with the two staged floating adjustment.

The floating adjustment is also applied before multipliers and can therefore be expected to result in an under-recovery of revenue.

Option 6

Design element	
Does the floating adjustment involve an adjustment to the reserve prices?	Yes – a km adjustment and second p/kWh adjustment
What measure of capacity is used to calculate the size of the floating adjustment?	Forecast and booked capacity
How is the floating adjustment calculated with known multipliers for different capacity products?	Multipliers are applied to initial reserve prices before the floating adjustment is added to the final tariff

Option description:

As per Option 4, but the second secondary adjustment (p/kWh) is made to the tariffs after multipliers are applied to calculate initial capacity product tariffs.

This means that the forecast floating adjustment accounts for the discount/multiplier that, for example, is applied to short term products compared to the annual tariff

This p/kWh adjustment applies on top of the original tariff for a given capacity product that reflected the capacity product multiplier.

Option 7

Design element	
Does the floating adjustment involve an adjustment to the reserve prices?	Yes – a two staged £/kWh adjustment is applied
What measure of capacity is used to calculate the floating adjustment?	Forecast and booked capacity
How is the floating adjustment calculated with known multipliers for different capacity products?	Multipliers are applied to initial reserve prices before the floating adjustment is added to the final tariff

Option description:

As per Option 5, but the second secondary adjustment (p/kWh) is made to the tariffs after multipliers are applied to calculate initial capacity product tariffs. This means that the forecast floating adjustment accounts for the discount/multiplier that, for example, is applied to short term products compared to the annual tariff.

This p/kWh adjustment applies on top of the original tariff for a given capacity product that reflected the capacity product multiplier to derive a final tariff.

Option 8

Design element	
Does the floating adjustment involve an adjustment to the reserve prices?	Yes – a km adjustment and second p/kWh adjustment
What measure of capacity is used to calculate the size of the floating adjustment?	Forecast and booked capacity
How is the floating adjustment calculated with known multipliers for different capacity products?	Multipliers are applied to initial reserve prices before the floating adjustment is added to the final tariff

Option description:

As per Option 6, except the second stage in the floating adjustment calculations is as follows: take target TO revenue, deduct known QSEC booking revenue, deduct revenue from forecast Short Term bookings (at modelled reserve prices including multipliers) and divide the remaining revenue across total forecast bookings.

Option 9

Design element	
Does the floating adjustment involve an adjustment to the reserve prices?	Yes – a two staged £/kWh adjustment is applied
What measure of capacity is used to calculate the size of the floating adjustment?	Forecast and booked capacity
How is the floating adjustment calculated with known multipliers for different capacity products?	Multipliers are applied to initial reserve prices before the floating adjustment is added to the final tariff

Option description:

As per Option 7, except the second stage in the floating adjustment calculations is as follows: take target TO revenue, deduct known QSEC booking revenue, deduct revenue from forecast Short Term bookings (at modelled reserve prices including multipliers) and divide the remaining revenue across total forecast bookings.

Option 10

Design element	
Does the floating adjustment involve an adjustment to the reserve prices?	Yes – a single p/kWh adjustment
What measure of capacity is used to calculate the floating adjustment?	Booked capacity
How is the floating adjustment calculated with known multipliers for different capacity products?	The size of the floating adjustment applied to the annual tariff is calculated to account for multipliers to capacity products

Option description:

Take the final reserve prices from under the existing methodology (50:50 adjusted prices). Calculate a floating adjustment to apply to the annual tariff so that when multipliers are applied to short term products, revenue recovery from forecast new and existing capacity bookings recover target allowed revenue.

This implies if a short term product is discounted to zero, there would be no floating adjustment applied to the short term product. Only products with a multiplier greater than zero contribute to allowed revenue recovery. Shorter term product acquires pay a multiplier of the annual floating adjustment.

The size of the floating adjustment is calculated assuming that all bookings pay the reserve price calculated in that year.

Option 11

Design element	
Does the floating adjustment involve an adjustment to the reserve prices?	Yes – a single £/kWh adjustment is applied
What measure of capacity is used to calculate the size of the floating adjustment?	Booked capacity
How is the floating adjustment calculated with known multipliers for different capacity products?	The size of the floating adjustment applied to the annual tariff is calculated to account for multipliers to capacity products

Option description:

Take final reserve prices as under the existing methodology. Calculate a floating adjustment to apply to the annual tariff so that when multipliers are applied to short term products, revenue recovery from forecast new and existing capacity bookings recover target allowed revenue.

This implies if a short term product is discounted to zero, there would be no floating adjustment applied to the short term product. Only products with a multiplier greater than zero contribute to allowed revenue recovery. Shorter term product acquirers pay a multiplier of the annual floating adjustment.

The size of the floating adjustment is calculated accounting for the prices paid by existing bookings.

ANNEX C INTERCONNECTOR FLOW MODELLING

This annex provides further details on the modelling approach for cross border flows. We consider in turn:

- assumptions applied in the modelling in terms of the structure of European gas markets;
- key steps in the calculations, including the assumptions made to model short-haul volumes at Bacton Beach.

C.1. Assumptions

C.1.1. Market structure and price levels

Modelling of cross-border flows for the model period (2015 to 2030) assumes no change in the structure of European wholesale gas markets.

Trading is assumed to take place between NBP, TTF and ZEE hubs as of today and the transportation capacity that must be bought to flow gas between markets also remains unchanged from the situation today. The *price* of transmission entry in GB of course does change year by year in the model.

The model calculates cross-border flows in response to price spreads calculated from Bloomberg day-ahead prices (as described in the main report) and marginal transaction costs incurred from shipper nominated flows from one European hub to the other. The model assumes the importation of gas (either from NBP to TTF or ZEE or from TTF or ZEE to NBP) has no impact on the wholesale price level and that utilisation of either interconnector is determined solely by the size of the price differential (day-ahead).

The fact that in reality importation or export of a large quantity of gas flow could influence wholesale price levels, and that utilisation could also be influenced by shipper contractual commitments, is implicitly captured in the shape of the supply elasticity curve applied to the two interconnectors (with the greater the price differential, the greater the flow up to a maximum import/export capacity).

As described in the main report, network tariff levels in GB and on the continent (e.g. GTS entry and exit charges) are linked to inflation. Therefore, in the absence of inflation adjustments to the wholesale prices used applied the model, this is likely to result in a distortion of the modelling of cross-border (arbitrage) flows. This is addressed within the model by applying a simplifying assumption to uplift NBP, ZEE and TTF prices by 3 per cent per year. Whilst this may not be the rate of price inflation projected for international wholesale gas prices in reality, it ensures the main objective of the GTCR model (to model impacts of changes in NTS charging *policy* (as opposed to the relative changes in network charges and wholesale prices)) is met.

The model user also has the option of choosing to run the model in real (2014/15 prices) by setting the inflation uplift assumptions to zero for all model inputs and calculations. This approach, however, will not derive the size of potential (nominal) tariff adjustments (e.g. floating tariff adjustments) for future years within the model.

C.1.2. GB / Netherlands flows

The transaction costs included in the NBP-TTF price spread calculations include assumptions for: BBL fuel charges; NTS exit commodity charge; GTCR modelled SO and TO entry commodity charges (where applicable under the policy scenario); Bacton CAM entry capacity charges, GTS entry capacity charge (indexed to inflation for future years).

C.1.3. GB / Zeebrugge flows

The transaction costs included in the NBP-ZEE price spread calculations include assumptions for: IUK fuel and electricity charges (pre-2018); additional cost of acquiring capacity for IUK (post-2018)[45]; NTS exit commodity charge; and GTCR modelled SO and TO entry commodity charges (where applicable under the policy scenario); and GTCR modelled Bacton CAM entry capacity charges.

To access the Zeebrugge hub from IUK, no entry tariff is charged by Fluxys because the hub is situated at the flange, not within Fluxys entry/exit system. There is, therefore, no transaction cost at the Zeebrugge end of IUK.

C.2. Key steps in calculations

C.3. Balgzand Bacton Line

For BBL, interconnector utilisation is determined using the user-defined S curve set out in the main report.

Modelled utilisation of the interconnector in GB import mode (NBP > TTF) reflects the price spread day ahead with deducted BBL fuel charges, GB entry commodity charges and GB entry capacity charges at Bacton CAM point[46].

Modelled utilisation of the interconnector in GB export mode (NBP < TTF) reflects the price spread day ahead with deducted BBL fuel charges, GB exit commodity charges and GTS entry capacity charges at Julianadorp.

C.4. IUK

For IUK, interconnector utilisation is determined using the user-defined S curve set out in the main report. Modelled utilisation of the interconnector in GB import mode (NBP > ZEE)

[45] See Section 4 – assumption provided by IUK as part of response to GTCR Technical Working Group.
[46] If not a sunk cost.

reflects the price spread day ahead with deducted IUK fuel /compressor charges, GB entry commodity charges and GB entry capacity charges at Bacton CAM point[47].

Modelled utilisation of the interconnector in GB export mode (NBP < ZEE) reflects the price spread day ahead with deducted IUK fuel/compressor charges and GB exit commodity charges (no transaction cost at Zeebrugge hub).

C.5. Short-haul volumes

Short-haul volumes consider the import-export decision for a shipper with gas at Bacton Beach rather than at NBP or ZEE hubs. As there must be a source for gas potentially available for short-haul at Bacton Beach, we assume that the total volume available for short-haul is constrained to BBL imports or UKCS gas field pipeline supplies to Bacton on the day. This means that there is a physical volume of gas available for potential short-haul export from Bacton Beach to Zeebrugge (via IUK).

The relevant marginal transaction charges for short-haul volumes are different to gas bought at NBP as market participants face a lower network charges as a result of paying the short-haul charge rather standard NTS entry capacity and commodity charges.

The price spread considered in this case is as follows:

(NBP (day ahead price) – NTS entry capacity and commodity charge) – (ZEE (day ahead price) – Short Haul Tariff – IUK Fuel/Compression charges)

C.6. Price data tickers

The following price data tickers from Bloomberg were used in developing the interconnector flow functionality in the GTCR model:

- NBPGDAHD Index
- ZEEBDAHD Index
- TTFGDAHD Index

[47] If not a sunk cost.

ANNEX D STORAGE MODELLING

D.1. Introduction

This annex describes in further detail the modelling functionality that can be applied within the GTCR model for LRS (Rough) storage.

D.2. Intrinsic value modelling

The first step in the modelling derives an initial hedging strategy for the LRS facility (to lock-in intrinsic value) based on buying the full storage capacity inventory for Q2 and Q3 (calendar year) based on forward prices at the start of the modelled financial year.

For Rough, we assume that given limits on the injection of gas each day the total storage space is filled up over the full 183 days in Q2 and Q3 (summer 2013/14). We assume the gas is then withdrawn from the facility over 90 days (in Q1 2014) at a locked in forward price for Q1. This provides for a hedged position (against the forward curve) for the storage gas trader and captures the basic value of the seasonal arbitrage

The storage gas trader, however, has the flexibility to increase profitability closer to winter 2013/14 by benefiting from the “rolling intrinsic value” of the storage facility through rebalancing withdrawals arising from favourable changes in NBP prices as monthly forward contract prices are published closer to Q1 delivery.

D.3. Rolling intrinsic value modelling

Therefore, the second step is to model how the storage gas holder in practice adjusts its daily withdrawals to capture the rolling intrinsic value of the storage gas. This intrinsic value can be captured because monthly prices published closer to the winter vary from the Q1 price used to establish the initial hedge.

The GTCR model applies the following:

- The forward curve from Bloomberg for the 1st September which is used to establish the initial withdrawal schedule for the winter.
- Withdrawal of the total storage inventory is profiled to the months with the highest ranked forward prices.
- Each month scheduled withdrawal is profiled within the month starting backwards from the end of the month.

The process of the storage gas inventory owner rebalancing its withdrawals on each gas day is modelled by comparing the daily day-ahead spot price to the forward prices of monthly contracts in the remaining months of the winter.

If the spot price is greater than the forward price in months, where there is known inventory, the storage gas owner is assumed to substitute volumes from the future month to dispatch (subject to daily withdrawal constraints) on the gas day in question.

This assumes that the storage gas holder trades its storage gas today to increase its locked in profit relative to the purchase price of the gas and the initial hedge. It then locks in to a future purchase in that future month to fulfil the initial hedged delivery liability.

We model a simple linear relationship of the spread between the daily NBP price and the forward month price to determine the total daily volume of gas chosen to displace dispatched gas in future months. This allows for dispatch for a given gas day to be less than total withdrawal capacity of the storage facility.

D.4. Injection modelling

The GTCR model contains a simple linear program (applied through Excel Solver) to solve for a least cost solution to fill the LRS storage facility space over the summer period. Daily injections to the facility are optimised given known wholesale (day-ahead NBP) prices for the first two quarters of the financial year in the modelling.

D.5. Alternative scenario based approach

As described in the main report, the GTCR model also includes the option to use historical flows as the basis for LRS (Rough) dispatch (rather than the calculations above) consistent with the approach that is applied for modelling MRS and SRS flows.

D.6. Price data tickers

The following forward NBP price data tickers from Bloomberg were used in developing the LRS flow functionality in the GTCR model:

- FN1 Comdty (1 month ahead)
- FN2 Comdty (2 months ahead)
- FN3 Comdty (3 months ahead)
- FN4 Comdty (4 months ahead)
- FN5 Comdty (5 months ahead)

To run the LRS storage withdrawal functionality, the model user must input this forward price data from the start of 1 October of the financial year (reflecting the forward prices for each month stating in November for 1st October).

This forward price data used in the modelling should be matched with the NBP daily spot price data series used (e.g. forward price series should match the daily price series used, e.g. for a historic financial year).

ANNEX E NTS USER BOOKING MODELLING

E.1. Introduction

This annex considers how we estimate the elements needed to model the price responsiveness of demand for capacity, and in particular the cost or value of a constraint from the perspective of various types of network user who have already decided to rely fully or in part on the availability of shorter-term (ST) NTS entry capacity at an ASEP.

E.2. Probability of a constraint

In the absence of detailed network modelling we have developed a relatively simple approach to the probability of constraints emerging.

As described in the main report, we assume that the probability of a relevant commercial constraint can be expected to correlate inversely with the surplus of technical (proxy by obligated) capacity and projected daily flows at an ASEP, taking into account existing booked capacity at the relevant ASEP.

E.3. Opportunity cost of constraint

As described in the main report, the GTCR model calculates the opportunity cost of a constraint at an ASEP and, therefore, values NTS capacity (by valuing the cost of an ASEP constraint) for the following supply sources by ASEP:

- dry gas fields;
- associated gas fields;
- condensate gas fields;
- LNG;
- storage;
- committed import pipeline; and
- interconnector (arbitrage) pipeline.

In Figures E1 and E2 overleaf, we describe the assumptions and stages in the calculations which are then used to arrive at the opportunity cost and booking strategy calculation for each of the supply sources above.

Figure E1 shows the calculations and assumptions used for estimating opportunity cost for UKCS supplies, whilst Figure E2 shows calculations and assumptions for the other supply sources that are used in the modelling.

The subsection which follows explains why a number of the inputs have been applied in the economic cost calculations for individual supply sources.

Figure E1: Opportunity cost calculations and assumptions for UKCS flows

1) Determine daily gas flow to arrive at ASEP (GWh)

2) Split daily gas flow by production from associated gas field, condensate gas field and dry gas field

3) Calculate loss of full day revenue at ASEP (shipper as owner of gas field) = Gas price at ASEP x Upstream profit margin x Production

4) Calculate loss of full day liquids and oil production = Oil (liquids) price x Oil (liquids) production x oil (liquids) Upstream profit margin

5) Calculate shipper (as buyer) margin loss = (Value multiplier x (NBP – ASEP price)) – (SO + TO commodity charge + ST capacity charge) x Production

6) Sum outputs from steps 3), 4) and 5) = total (economic) loss of full day revenue from ASEP constraint

7) Determine expected value of constraint = output of step 6) x daily probability of constraint at the ASEP

8) Determine LT booking strategy deficit = Cost of LT capacity – Cost of ST capacity – Expected value of constraint

9) If output from Step 8 is greater than zero then ST capacity should be booked, otherwise LT capacity

10) If more than two thirds of days in quarter are days where LT capacity is more valuable than ST capacity (on expected value basis) then book QSEC to maximum quarter flow

Figure E2: Opportunity cost calculations for non-UKCS supply sources

1) Determine daily gas flow to arrive at ASEP (GWh)

If MRS flow then determine NBP-ASEP margin loss

Take expected withdrawal at ASEP

Multiply by NBP – ASEP margin =
Source value multiplier (220%) x ((Q1 winter price – average of Q2 and Q3 summer price) – (ST capacity charge – SO and TO commodity charge)

Loss of margin is therefore a multiplier of the underlying intrinsic summer – winter storage value

If LRS flow then determine NBP-ASEP margin loss

Take expected withdrawal at ASEP

Multiply by NBP – ASEP margin =
Source value multiplier (100%) x ((Q1 winter price – average of Q2 and Q3 summer price) – (ST capacity charge – SO and TO commodity charge)

Loss of margin reflects the underlying intrinsic value of the storage facility

If LNG then determine loss on full day gas at ASEP

Take gas price at ASEP

Multiply by Upstream profit margin

Multiply by value multiplier at source

Multiply by production

If pipeline or arbitrage importation then determine loss of margin revenue

Take expected flow

Multiply by NBP – Eurohub trading spread =
Eurohub trading spread – avoided pipeline cost – ST capacity charge – TO entry commodity charge – SO entry commodity charge

This margin loss calculation is used for interconnector and Norway pipeline flows to the GB market

2) Sum outputs from above (depending on supply source) = total (economic) loss of full day revenue from ASEP constraint

3) Determine expected value of constraint = output of step 6) x daily probability of constraint at the ASEP

4) Determine LT booking strategy deficit = Cost of LT capacity – Cost of ST capacity – Expected value of constraint

5) If output from Step 4 is greater than zero then ST capacity should be booked, otherwise LT capacity

6) If more than two thirds of days in quarter are days where LT capacity is more valuable than ST capacity (on expected value basis) then book QSEC to maximum quarter flow

E.4. Key assumptions

The assumptions used in the economic (opportunity) cost calculations for each of the supply sources are listed in Section 4.

For UKCS gas:

- A value multiplier assumption is applied in the loss of NBP – ASEP margin calculations to reflect that value achieved from production for different types of gas fields may be less or more than the price differential (to reflect source flexibility).
- An upstream profit margin is applied to loss of revenue at the ASEP calculations to reflect that the cost for the owner of the gas is the margin on the day from sale at ASEP relative to costs of production.
- Oil and liquids production by ASEP are calculated from forecast gas production at ASEP using a fixed flow rate units conversion rate from Million standard cubic feet of gas per day to barrels oil per day (see assumption in Section 4).
- MRS and LRS value of constraint methods both apply a relatively simple assumption that the economic loss was equal to the amount paid for storage i.e. no mitigation. This simple approximation could be replaced by a daily calculation which compares the NBP price on the day of constraint with a (lower) price further down the price duration curve to reflect a more nuanced loss of value appropriate to different storage facility injection cycles.

As regards the value multipliers used for LRS and MRS facilities:

- The value multiplier for LRS is set equal to 110% to reflect the typical premium that Rough commands above the basic intrinsic value.
- The 220% value multiplier for MRS is based on typical Hornsea values relative to Rough of a few years ago.

Both are parameterised inputs in the model. Lower values for MRS facilities might for example be investigated to reflect the fact that flexibility values are generally somewhat lower in recent market conditions.

For LNG the calculation of value of constraint was developed to be broadly consistent with some now rather dated upper end calculations by Deloitte (requested by Ofgem) for loss of full economic value for a prolonged delay in accommodating LNG at Milford Haven. [48]

[48] Analysis of the economic costs of disrupting LNG supply chains from "Proposed Incentive Arrangements for the Provision of NTS Entry Capacity at Milford Haven" (April 2006) - https://www.ofgem.gov.uk/ofgem-publications/56364/13516-6306.pdf

These estimates assumed that whole LNG cargoes were diverted (and in worst case unable to find an alternative market). The model might be adapted in future to consider a more subtle calculation based on deferred use of storage inventory at the LNG terminal – essentially a calculation based on the difference between the NBP price on a day of constraint vs a (lower) price later in the withdrawal schedule.

This would assume a certain latitude to defer export before the next LNG cargo needs to be accommodated and a sustained constraint would jeopardise this assumption and presumably increase the value of lost opportunity.

For all interconnector pipeline imports, the NBP – Eurohub trading spread is based on the NBP – ZEE spread, as a simplifying assumption.