Call for input

Energy price cap: technical approach to Market Wide Half-Hourly Settlement

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We are consulting on our initial thinking on how the default tariff price cap may need to develop to accommodate Market Wide Half-Hourly Settlement (MHHS). MHHS will result in changes in how suppliers are settled when purchasing electricity to match their customers' demand.

In this call for input, we consider that to adapt the cap, we need to update how we set the single-rate cap level, design at least one time-of-use cap variant and consider whether further risk mitigations are required to address differences between groups of customers and supplier customer bases.

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Executive summary

In November 2025, we published our Markets Regulatory Vision and Strategy for the retail market. It sets out the outcomes we want to achieve in energy retail markets by 2030 and how we plan to get there. We seek energy markets that deliver for all customers through regulation that provides confidence and protections to consumers, whilst enabling innovation and investability, supporting Clean Power 2030 goals and economic growth.

The default tariff cap ('cap') forms a fundamental part of the regulatory framework for the domestic retail market. How we set the cap has a significant bearing on the investability of the sector, incentives for innovation and the move towards greater flexibility in how consumers use their energy.

This call for input is primarily concerned with how we cap wholesale costs for default tariff customers. In recent weeks we have seen significant movement in gas markets in reaction to the war in Iran and the implications for global supply of oil and liquified natural gas (LNG). It is too early to forecast how this may affect consumers in Great Britain, which will depend on how acute disruption to supply is and how long it persists. We are monitoring the situation closely and will keep under close review whether it requires any changes to our approach to the price cap and adjacent policy. However, it is not the focus of this call for input which is focused on adapting to the structural changes to the electricity market in Great Britain.

The market is undergoing significant change with the introduction of Market Wide Half-Hourly Settlement (MHHS). Settlement accounts for the differences in demand and supply in the energy system. MHHS plays a key part in delivering Clean Power 2030 and the transition to net zero. It incentivises suppliers to offer tariffs to customers that reward them for using energy outside peak periods (periods of high demand and prices).

In future, we want to see a market that is moving away from a simple commodity model, towards a more diverse set of products and services aimed at unlocking system value. In our Markets Regulatory Vision and Strategy, we said we will focus on reforms to ensure the cap is fit for purpose in a world of MHHS. We seek to ensure the cap is not a barrier to voluntary consumer-led flexibility. In doing so, we will ensure the cap continues to protect consumers from the loyalty penalty. Our review of the wholesale allowance in the cap considers what changes we may need to make to the cap methodology to support this vision.

Under MHHS, suppliers will be charged based on their customers' actual usage patterns as opposed to the notional profiles previously used. This will expose suppliers to a greater variation in costs depending on their customer base. Overall, in the short term we expect there will be small differences in suppliers' costs as they move from using the notional profiles to customers' actual demand (though note the impact from non-wholesale charges that are allocated based on peak consumption could be higher). However, despite small initial changes in cost at an aggregate level, we expect there to be a greater variation in costs across suppliers where their customer bases differ.

There is greater uncertainty about the longer-term impacts due to variability across factors such as data consent, take-up of different tariffs, policy changes, roll out of low carbon technologies and the role of new participants like aggregators. However, we consider these cost impacts could be significant, coupled with greater cost variation between suppliers as customers change their usage and move across different products. We consider it is important that we start to adapt the cap now to these emerging pressures and opportunities.

Overall, there are three approaches we could take to updating the cap wholesale allowances in response to MHHS. Firstly, under incremental reform, we could retain the current cap structure of having a single rate cap and a multi-register cap that allows for time of use (ToU) default tariffs with multiple unit rates. Secondly, we could move the cap to ToU only, which would result in all default tariff customers being put on a ToU tariff. Lastly, we could change the structure of the cap itself (for example by setting caps for each half-hourly block of energy that then allow suppliers to structure their own tariffs). We intend to proceed with the first approach and retain the current cap structure. We consider this incremental approach to change is appropriate given the shorter term and immediate market changes we are observing. In the longer term, we may reconsider how we set and structure the wholesale allowances within the cap but would have to be mindful of any distributional impacts.

To adjust the cap, we propose the following three broad directions:

- Firstly, we need to set a wholesale allowance that allows the cap to track and reflect the costs of serving default tariff customers as this group evolves over time.
- Secondly, we need to consider whether and how we account for some diversity across suppliers' cost bases. As cost diversity increases, so do the challenges that arise in setting one cap level across the market. We may want to reflect some of these differences, but this does not mean that every supplier will see its costs covered in all circumstances.
- Thirdly, we need to develop the cap for customers who want to change their usage patterns (ie pay by time-of-use). This would support the growth of default ToU tariffs and contribute to delivering Clean Power 2030. The cap cannot deliver all consumer-led flexibility, but it can serve as an important enabler.

To achieve these three areas, we consider we need to update how we set the single-rate cap level, design at least one ToU cap variant and consider whether further risk mitigations are required to address differences between supplier customer bases. Over these areas there are several design choices we will need to consider depending on how we think the market may evolve over time. These include:

- how we benchmark a demand profile for setting the wholesale allowance;
- whether the demand profiles need to vary across cap parameters;

- how many ToU variants we want to set to cover different types of customers and technologies (for example electric vehicle charging);
- how prescriptive we want to set the ToU variant(s) when considering the unit rates and time bands they apply to; and
- the approach for updating the demand profile used to set the allowances.

This call for input is open until 27 April 2026. We welcome comments from all stakeholders, especially where these are supported by evidence. We also welcome bilateral meetings with stakeholders to discuss this document. Please get in touch if you want to arrange a meeting.

In parallel, we have collected and are analysing detailed supplier data on customer demand, which will form the basis of our evidence in setting the wholesale allowances. Following this call for input, we will consider publishing a technical working paper over the summer that seeks to explore the methodology by which we would set the cap allowances (for example the shaping allowance) incorporating the data we have collected.

1. Introduction

In this chapter we set out the objective of the Market Wide Half-Hourly Settlement phase of the price cap wholesale allowance review, the purpose of this call for input and related publications.

Purpose of this call for input

1.1 The purpose of this call for input is to set out our initial thinking and seek views on how the default tariff cap ('cap') may need to develop to accommodate the changes in how suppliers are settled when purchasing electricity to match their customers' demand. Under Market Wide Half-Hourly Settlement (MHHS), suppliers will be settled based on their customers' actual half-hourly usage rather than an estimate as currently used. This means the cost suppliers face will be reflective of how and when their customers use electricity.

1.2 In the paper, we set out an introduction to the wholesale allowance, our views on the case for change and potential options we may need to consider in updating the cap. We seek evidence-backed, written stakeholder feedback to inform our thinking.

Context and related publications

1.3 We recently published our long-term strategy for energy retail markets, aiming for regulation that ensures consumer protection, fosters innovation, and supports investment in line with the UK government's Clean Power 2030 objectives and economic growth. Achieving this vision requires both investability and innovation in retail markets, as these factors lead to improved outcomes for consumers and the wider economy. The cap remains a central regulatory tool, significantly influencing investment and innovation, and must be adapted to align with our strategic goals, whilst continuing to fulfil its objective of protecting default tariff customers.

1.4 The cap was introduced in 2019 to tackle inefficiency and the "loyalty penalty" for less engaged customers. Government removed its planned end date in 2022, making the cap an enduring feature of the regulatory landscape. However, significant events such as the COVID-19 pandemic and the energy crisis have since placed substantial strain on the cap, necessitating reactive interventions to maintain market stability with the majority of customers temporarily having moved onto capped default tariffs.

1.5 As market conditions have started to stabilise, switching levels and the number of customers on fixed tariffs have returned to normal levels, though the market now features fewer suppliers and ongoing challenges from elevated prices and consumer debt. The sector still faces considerable risks from market volatility, highlighted by recent events, and wider shifts towards clean energy, including the implementation of MHHS. Supporting this transition is vital for achieving climate goals and long-term bill stability.

1.6 Flexibility in how energy is used is key to hitting the Clean Power 2030 goal of delivering a clean electricity system by 2030, which will protect consumers, create jobs, and transform the UK's energy system while paving the way to net zero by 2050. We seek to develop an energy system that is more flexible as we meet the needs of homes and businesses through harnessing the intermittent nature of renewable energy. The approach of the UK government and Ofgem to supporting consumer-led flexibility will allow all consumers to see the benefits of both lower energy bills and greater control over their bills.

1.7 In July 2025 the Department for Energy Security and Net Zero (DESNZ) published the Clean Flexibility Roadmap, developed by DESNZ, Ofgem and the National Energy System Operator (NESO), which sets out the UK government's vision for flexibility and how we will deliver it. The commitments Ofgem made in this roadmap will unlock barriers to consumer-led flexibility, greater flexibility capacity and a governance framework to monitor delivery, adapt, and identify new actions. Additionally, in our Markets Regulatory Vision and Strategy, we said we will focus on reforms to ensure the cap is fit for purpose in a world of MHHS. In doing so, we will ensure the cap continues to protect consumers from the loyalty penalty. The objective of the cap as set out by the Domestic Gas and Electricity (Tariff Cap) Act 2018 ("the Act") is to protect existing and future default tariff customers. We will seek to ensure it continues to do that as we consider methodological changes through this review. While the cap plays a role in consumer-led flexibility, it is not the only contributing factor. Therefore, how we set the cap forms just one, albeit an important, part of our overall vision for enabling greater energy flexibility.

1.8 This call for input mainly focuses on how MHHS will impact supplier commodity costs, particularly in how they purchase energy contracts. For this reason, we focus on discussing the wholesale allowance in the cap. However, we are mindful that there are certain non-commodity costs (Capacity Market, Transmission Network Use of System and Distribution Use of System charges) where charges are allocated fully or in part based on customer usage during peak times. We consider these non-commodity costs to also be in scope of this review as the way they are allocated may change with the availability of half-hourly demand data.

1.9 In parallel to our review of the MHHS impacts and as part of our wider review of the cap's wholesale allowance, we are also reviewing other wholesale costs referred to as additional wholesale allowances. We published two calls for input last year: one on setting an enduring Unidentified Gas (UIG) allowance and the other on updating the Contracts for Difference (CfD) methodology. We expect to update stakeholders on these areas in the coming months. In response to this call for input, we also welcome any views on areas we have not focused on here but are covered by the wholesale allowances (for example the cost of transacting energy).

1.10 Across this document, we set out the parameters of the review, optionality to consider and our intended direction of travel.

Related publications:

- Ofgem: Markets Regulatory Vision and Strategy
- DESNZ: Clean Power 2030 Action Plan
- DESNZ, Ofgem and NESO: Clean Flexibility Roadmap

Call for input stages

Stage 1 Call for input open: 25 March 2026

Stage 2 Call for input closes. Deadline for responses: 5 May 2026

Stage 3 Responses reviewed and published: Spring/Summer 2026

Stage 4 Further stakeholder engagement: Summer 2026

How to respond

We want to hear from anyone interested in this call for input. Please send your response to the person or team named on the front page of this document before the response deadline.

We have asked for your feedback in the questions listed at the end of chapters 2 and 3. Please respond to each one as fully as you can.

We will publish non-confidential responses on our website.

Your response, data, and confidentiality

You can ask us to keep your response, or parts of your response, confidential. We will respect this, subject to obligations to disclose information. For example, under the Freedom of Information Act 2000, the Environmental Information Regulations 2004, statutory directions, court orders, government regulations, or where you give us explicit permission to disclose. If you do want us to keep your response confidential, please clearly mark this on your response and explain why.

If you wish us to keep part of your response confidential, please clearly mark those parts of your response that you do wish to be kept confidential and those that you do not wish to be kept confidential. Please put the confidential material in a separate appendix to your response. If necessary, we will contact you to discuss which parts of the information in your response should be kept confidential and which can be published. We might ask for reasons why.

If the information you give in your response contains personal data under the General Data Protection Regulation (Regulation (EU) 2016/679) as retained in domestic law following the United Kingdom's withdrawal from the European Union ("UK GDPR"), the Gas and Electricity Markets Authority will be the data controller for the purposes of

GDPR. Ofgem uses the information in responses in performing its statutory functions and in accordance with section 105 of the Utilities Act 2000. Please refer to our Privacy Notice on consultations, see Appendix 4.

If you wish to respond confidentially, we will keep your response confidential, but we will publish the number, but not the names, of confidential responses we receive. We will not link responses to respondents if we publish a summary of responses, and we will evaluate each response on its own merits without undermining your right to confidentiality.

How to track the progress of a Call for input

1. Find the web page for the Call for input you would like to receive updates on.
2. Click ‘Get emails about this page’, enter your email address and click ‘Submit’.
3. You will receive an email to notify you when it has changed status.

A Call for input has two stages: ‘Open’ and ‘Closed’.

2. Background and case for change

In this chapter, we set out the background of how settlement is changing and highlight the impacts we consider this will have across customers, suppliers and the cap.

The role of MHHS

2.1 Consumer-led flexibility refers to voluntary actions consumers may take to reduce or increase the amount of electricity they use at a particular time, in response to a signal (such as a price signal). It can help consumers save money and improve system efficiency, by using electricity at times that are beneficial to the system and being rewarded for doing so. Improving system efficiency in this way also brings down costs for all consumers. In particular, consumer-led flexibility can harness the full value of low carbon technologies (LCTs) like electric vehicles (EVs) and heat pumps.

2.2 Retail markets need to transform in the next few years to support the required 10-12 GW of consumer-led flexibility capacity by 2030, across domestic and non-domestic customers, estimated by the Clean Flexibility Roadmap. We want to see investment in new products and services that improve customer outcomes and make it simple for consumers to engage with flexibility such as time-of-use (ToU) tariffs, where electricity prices vary at different times of the day and night. For example, customers can be offered cheaper off-peak rates to charge their EV at night time. Suppliers and third parties like aggregators can also develop attractive propositions for consumers on single rate tariffs to help them use electricity more flexibly, for example, by giving them a discount on their bill in return for reducing use of household appliances like dishwashers during winter evenings.

2.3 MHHS is a key enabler of consumer-led flexibility and therefore will play a key part in delivering Clean Power 2030 and the transition to net zero. It does this by enabling the specific “time-of-use” costs of supplying different customers, based on what time of day or night they use electricity, to be allocated to their supplier. Suppliers will thus be incentivised to reduce their costs by sending price signals to customers to shift their demand to cheaper off-peak periods. For example, when customers choose to adopt ToU tariffs, suppliers can charge them less when using electricity outside peak periods and more for using electricity during peak periods, to better reflect the cost of serving them.

What is settlement and how is it changing

2.4 The electricity settlement process, which is run by Elexon, ensures the financial and operational integrity of the electricity market. Broadly, there are two aspects to the settlement process: (1) the physical system balancing where generators are instructed to increase or decrease output to balance the system; and (2) market clearing, where the wholesale contracts suppliers have purchased to supply energy to their customers are matched against the customers' demand. MHHS primarily impacts the latter of these two mechanisms.

2.5 To facilitate market clearing, Elexon works out each supplier's net position by reconciling the electricity supply volumes it purchased in the wholesale market with what its customers used. When there is a mismatch (or imbalance), suppliers are either paid for excess volumes or charged for any shortfalls at a price referred to as the imbalance price. These positions are calculated on a half-hourly basis, referred to as settlement periods, which means there are 48 daily settlement periods in total. Suppliers pay or receive a different imbalance price in each settlement period.

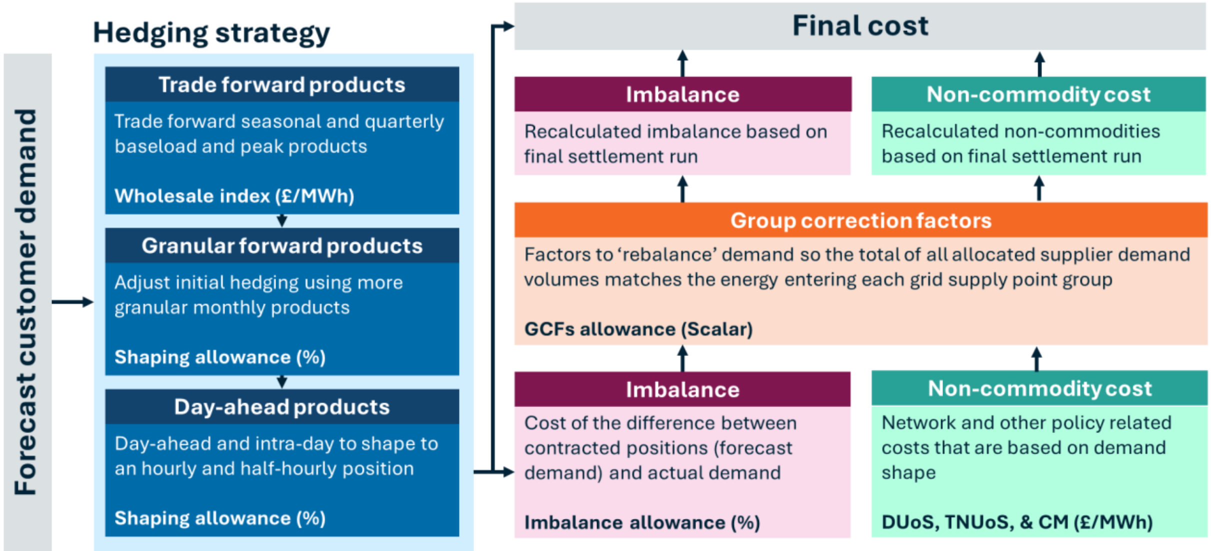
2.6 Before the introduction of MHHS, half-hourly consumption data has not been available to use in the settlement process for domestic customers. Elexon, instead, has estimated domestic customers' half-hourly consumption using assumed notional "profile classes" (profile class 1 and 2) for settlement purposes, in a process described as non half-hourly settlement. These profile classes represent an assumed consumption profile for each half-hourly period in a day for an average domestic customer and are updated annually based on a historic view of a sample of industry-wide customer consumption data.

2.7 In practice, this means suppliers try to match the demand profile set by the profile class so that the volume of energy purchased in each settlement period matches the demand from their customers. By doing so they limit their exposure to the imbalance price which creates an element of cost recovery uncertainty (which can be a benefit or a cost to suppliers, depending on whether the imbalance price is higher or lower than the price paid by the supplier if it purchased volumes in the day-ahead market).

2.8 Suppliers refine their wholesale position through buying and selling from less granular to more granular energy contracts; this process is referred to as shaping. For example, a supplier may purchase a quarterly contract covering energy delivery through October – December. Demand is typically greater in December due to colder weather and shorter days so the supplier may then refine its position by selling some October delivery and purchasing more December delivery. Suppliers will carry out these transactions in the day ahead market to match the shape they are settled against.

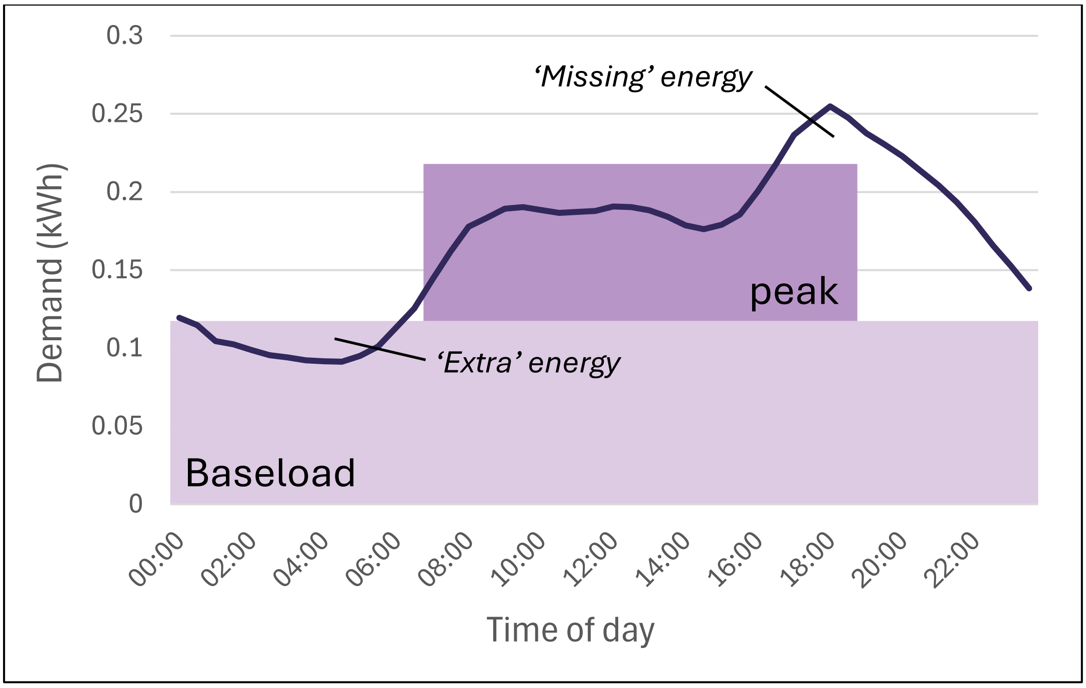
2.9 Figure 1 below shows how the different allowances fit together. The visualisation aims to link the actions suppliers take with steps set out within the cap's methodology. However, these steps are not always directly comparable. For example, the cap's wholesale index assumes suppliers purchase only quarterly products, while they may decide to trade both seasonal and quarterly products on the forward market instead. We further explain how we set the wholesale allowances for the steps within Figure 1 in Appendix 1. Figure 2 shows a simplistic view of how suppliers seek to shape demand from peak and baseload contracts to a half-hourly demand profile.

Figure 1 – Visualisation of demand profile related allowances



Note: Line losses have been omitted from the visualisation for clarity.

Figure 2 – Shaping from peak and baseload contracts to a half-hourly demand profile



2.10 The key change to the market clearing process that MHHS causes is the usage of actual half-hourly demand data to calculate imbalance positions rather than the use of notional profile classes. In contrast to traditional meters, smart meters measure customers' actual half-hourly electricity consumption. Suppliers have been able to choose to use this data in settlement, but until now there has not been a requirement to do so. The introduction of MHHS will require, for the first time, this half-hourly demand data to be used for settlement for customers with smart meters who consent to share their data. This means that instead of customers being settled against their assumed consumption under the profile classes, these customers will instead be settled against their actual consumption for each half-hour period of the day. In this way, MHHS will make the settlement process more accurate and expose suppliers to the actual demand position of their customers.

2.11 For customers who have been migrated to the new settlement arrangements but are not settled based on their actual half-hourly demand, Elexon will replace its profile classes with its new load shaping service (LSS). The LSS estimates half-hourly demand using actual half-hourly data shared via smart meters across the market, aggregated by specific customer cohorts (such as region). Similar to the profile classes, the LSS will be used to estimate the half-hourly consumption of customers who do not share their half-hourly data but is expected to be much more accurate than current non half-hourly settlement, which is based on a much smaller sample size.

2.12 Under the LSS, most domestic customers not settled on their half-hourly data will be settled on a single load shaping category (LSC) specific to their region. Each region represents 1 of the 14 grid supply point (GSP) groups for each of Great Britain's 14 regional distribution network operators. These load shaping categories are broadly comparable with profile class 1.

2.13 Customers on traditional ToU tariffs like Economy 7 and Economy 10, and who are on a smart meter, will not be settled according to the load shaping category equivalent of profile class 2. Instead, these smart meter customers will be settled against the LSC equivalent of profile class 1, alongside most other domestic customers. As a result, MHHS will reduce the future number of customers settled on the equivalent of profile class 2. Customers with a traditional meter on Economy 7 and Economy 10 tariffs will be settled against a different LSS profile.

2.14 For customers who have been migrated to MHHS, the timetable for final settlement for suppliers is being shortened from the current 14 months process in stages. By the end of 2027, once all customers have been migrated to MHHS, final settlement is scheduled to take 4 months.

2.15 The permanent migration of customers to half-hourly settlement began on 28 October 2025. From this date, customers who transition to MHHS will either be settled on their half-hourly data or the LSS. The migration is staggered, with individual suppliers transitioning customers at set intervals throughout the programme. The full migration is expected to take 18 months and be complete by

7 May 2027. However, Elexon anticipates that approximately 80% of meters will have been migrated by October 2026.

Impact on suppliers

2.16 The cost impact on suppliers ranges over several areas. While the availability of half-hourly demand data through MHHS is primarily linked to changes in the settlement process, it will also be used to allocate other charges that are based on usage during peak period. This means MHHS impacts both commodity and non-commodity costs.

2.17 We consider the impacts of MHHS on suppliers operating the cap can be broadly divided into short-term and medium/long-term. The short term, or “Day one impact”, can be defined as the period between the start of a supplier’s migration of its customers to MHHS and the immediate period following completion of its migration. In the initial stages, when only small numbers of customers have been migrated and the majority are still being settled on a non half-hourly basis, we do not expect MHHS to have a significant influence on a supplier’s overall cost to serve. We only expect any potential MHHS impacts to start to occur once a supplier has migrated a critical mass of its customers. Given that suppliers have different migration schedules, which will impact in which order different cohorts of customers are migrated, the number of migrated customers needed to form this critical mass will be different across suppliers.

2.18 We consider the medium/long-term impacts to be defined as the period where there is adoption of diverse tariffs and LCTs. At this point, we would expect a much greater level of consumer-led flexibility, potentially with additional market participants such as aggregators. There is much greater uncertainty about medium/long-term impacts of MHHS given that the scale and timing depend on a variety of factors such as adoption of smart meters and consent to data sharing, take-up of ToU tariffs and the policy approach to consumer-led flexibility.

2.19 Throughout this document, we discuss the demand profile of customers. This is important for determining the costs that suppliers face when purchasing energy and determining the allocation of non-commodity costs. In this chapter, we talk about demand profiles in relation to how they may change and the impact that could have on suppliers and customers. In the following chapter, we discuss options for setting the demand profile used in the cap.

Cost diversity and changes in incentives

2.20 MHHS will expose suppliers to the actual costs of their customers rather than the notional profiled costs currently used for settlement. This means that, in practice, they will be incentivised to accurately estimate their customers’ actual demand when purchasing energy contracts, to avoid exposure to imbalance prices. In doing so, where their customers use more electricity at peak times (and hence can be described as "peaky") than the profile class previously assumed, they will incur a higher cost (the opposite applies where customers are less peaky).

2.21 We expect suppliers will face greater incentives to price the differences in cost to serve generated by differences in their customers' actual demand. Prior to MHHS, a supplier would be indifferent about whether a customer consumed during peak periods or off-peak periods given they would be settled against the profile class, regardless of when they consumed energy. However, exposure to customers' actual demand will incentivise suppliers to shift customer usage away from peak periods to reduce their costs. Suppliers can try to achieve this through ToU tariffs to encourage customers to shift their demand away from peak periods or by rewarding customers that already use electricity during off-peak periods with discounts on their bills.

2.22 In future, suppliers could compete on their ability to assist customers in shifting their demand patterns. This means that the average "peakiness" of a supplier's customer base may be, to a degree, within its control. We may in future consider suppliers' ability to incentivise consumer-led flexibility as part of overarching efficiency. However, there are likely to be other factors outside a supplier's control that also have an impact. This is similar to how we consider both efficiency and non-efficiency factors when benchmarking costs elsewhere in the cap (for example operating cost allowances).

Commodity cost impacts

2.23 Commodity costs relate to the wholesale costs suppliers incur for supplying energy to their customers. One key element of commodity costs that are impacted by MHHS are shaping costs. Shaping costs are incurred when suppliers buy and sell more granular contracts closer to delivery to refine their position. Where their position was previously based on profile classes, with MHHS it will be based on actual demand.

2.24 In the short term, in aggregate, we expect there to be minimal differences between the average half-hourly demand shape under the current profile classes and that based on actual demand. This is because we do not think that customers' underlying actual demand will initially change. As a result, we expect only a small impact on commodity costs from MHHS across the market in the short term. However, actual demand may expose suppliers to differences in costs between groups of consumers. We consider supplier costs will vary depending on their customer base. We do not anticipate these differences to initially be large enough to create competitive distortions among suppliers or undermine investability.

2.25 To assess the short-term impacts on commodity costs, we issued a voluntary data request to analyse the movement from profile class to actual demand. Nine suppliers provided data comparing wholesale commodity costs for default tariff customers settled on half-hourly consumption against traditional non-half-hourly settlement (profile class 1). The analysis was carried out using 12 months of smart meter data and day-ahead pricing.

2.26 While the general methodology employed by all suppliers was the same, there were small differences between suppliers which would reduce the consistency of the analysis. This included differing levels of data cleaning, granularity (half-hourly or hourly), sample sizes, and dates used in the analysis. We intentionally sought the analysis in this way to keep the ask proportionate and where possible, we have controlled for these differences.

2.27 Through the voluntary analysis, we found the weighted average impact on commodity costs across the nine suppliers was less than £1 (approximately £0.30 reduction in cost). Furthermore, for most suppliers, the impact of customers being settled on half-hourly data was small, between ± £1 per typical customer. The range across suppliers was approximately £3.90 with an approximate £2.70 increase for the supplier who saw the highest cost increase.

2.28 The analysis also highlighted the extent to which customers' wholesale commodity cost to serve differs depending on when they consume electricity. The weighted average difference in cost between the 10th and 90th percentile cost to serve customers was approximately £22. The average weighted difference between the 10th percentile and average cost to serve customer was typically £10-11. These figures were consistent across most suppliers.

2.29 We also ran a similar preliminary analysis on a subsample of supplier demand data we collected. That analysis found a slightly higher weighted average impact of a £1 increase in costs. Differences are likely due to factors such as weightings across the sample, counter-factual positions and the wholesale prices used to calculate cost.

2.30 This data would suggest that ToU tariffs would not be priced significantly cheaper than the default tariff for such customers, on the basis of their lower commodity cost to serve alone (although these savings do not take into account any additional savings they would make from a ToU tariff by shifting their consumption). We would therefore expect to see only a gradual increase in the cost to serve of default tariff customers after MHHS, if relatively small numbers of customers with a flatter demand profile initially switch to ToU tariffs. However, there are several factors, such as uptake of LCTs and consumer-led flexibility policy, that provide further uncertainty to the scale of incentives.

Cost and demand uncertainty

2.31 A supplier incurs imbalance costs when there is a difference between its net demand position and the amount of electricity that it has purchased in a given half-hour. Imbalance costs depend on a supplier's ability to accurately forecast their customers' demand, considering variables such as changes in customer numbers and weather conditions. There may be greater uncertainty in imbalance positions as suppliers move from using profile classes to actual demand. Profile classes used in non half-hourly settlement inherently incorporate a degree of averaging and so are easier to forecast. However, under actual half-hourly settlement, suppliers could have different demand shapes which would be subject to more variation.

2.32 We expect the risk of forecast error resulting from MHHS to decrease over time, as suppliers gain access to more demand data and have greater experience in estimating actual demand. Overall, greater imbalances create uncertainties for supplier cost recovery. While imbalance prices are not punitive relative to day-ahead prices, it may still be riskier for a supplier to leave its shaping to the imbalance mechanism. This is because balancing actions closer to real time may incur additional costs. This might not matter if a supplier was equally likely to be out of balance in either direction relative to the system. However, common factors that impact overall demand level and shape (such as weather) may increase the chances that suppliers are out of balance in the same direction (in a given half-hour), and this in turn may increase the chances that the system is also out of balance in the same direction.

2.33 In the longer term, we expect greater cost variations across suppliers. For example, greater adoption of ToU tariffs will further incentivise suppliers to move customers off single-rate tariffs (including the cap) and onto appropriate ToU tariffs to lower their costs. If cheaper cost to serve customers with flatter profiles move off the cap onto ToU tariffs, then the residual default tariff customers will be more costly to serve. This may lead to suppliers with an above average proportion of default tariff customers facing a higher cost to serve. However, the extent to which such impacts outturn will depend on several factors, including suppliers' commercial strategies.

Non-commodity cost impacts

What are the costs and how do they affect the cap

2.34 Non-commodity costs relate to the costs of energy supply other than the energy itself (ie the wholesale or commodity element of a customer's bill) such as delivering the energy, maintaining the infrastructure and administering the system and support schemes. These include operating, policy and network costs which suppliers incur to deliver customer service, government schemes, transmission and distribution network infrastructure and other system functions.

2.35 In this section of the document, we refer to the three non-commodity charges which vary based on the level of consumption during half-hour demand time bands. The three non-commodity charges that are allocated by peak usage fully or in part are: Transmission Network Use of System (TNUoS), Distribution Use of System (DUoS), and Capacity Market (CM) charges. We explain in more detail how these costs are defined and calculated in Appendix 1.

2.36 The original focus of this review was to consider the impact on the wholesale allowance of MHHS. We have broadened the scope to include the impacts of MHHS on non-commodity costs within the cap which we are still investigating. What we set out in this call for input are our initial views and hypotheses based on our understanding so far. We welcome further engagement with stakeholders on this complex issue.

2.37 Prior to MHHS, demand has been settled using profile class assumptions to estimate customers' electricity consumption across different time periods of the day. As a result, we understand that suppliers are billed for these non-commodity charges based on assumed average half hourly consumption shapes, rather than customers' actual usage. Within the cap, as with commodity costs, non-commodity charges for single-rate customers are calculated using a profile class 1 profile, while charges for multi-register customers are calculated using a profile class 2 profile.

2.38 As with commodity costs, we understand migration to MHHS will change this approach to setting non-commodity charges by settling customers on their actual half-hourly consumption. This is expected to expose suppliers to costs that reflect real peak-time usage, rather than assumed average demand, and to result in charges that are more closely aligned with customers' actual consumption during peak periods.

2.39 On an aggregate basis, non-commodity charges with a half hourly shape accounted for approximately £190 per customer for the January to March 2026 cap period. Costs are allocated in line with how suppliers are charged: fixed costs are recovered through the standing charge, while those that vary with consumption are recovered through the unit rate. Approximately half of non-commodity charges are recovered through the volumetric element of the cap, and the majority of these costs are driven by peak time consumption. As a result, we expect these non-commodity charges to be impacted by MHHS to the extent that actual demand is different to the demand profile used under non half-hourly settlement.

Forecasting demand

2.40 Under the current arrangements, suppliers submit estimates of their customers' expected peak demand so their non-commodity charges can be calculated. Under MHHS, we expect suppliers will be exposed to actual peak-time demand rather than a blended average of each customer (where settled half-hourly), increasing the potential variability of costs between suppliers and among customer groups where peak usage differs materially.

2.41 Network tariff rates charged to suppliers are determined using a model which calculates costs, in part, based on suppliers' forecast of consumption. This allows network companies to set tariff rates for the upcoming delivery year. Under MHHS, we understand these forecasts will be based on customers' actual expected demand rather than on assumed average profile classes as under non half hourly settlement. As noted above, there may be greater risk of inaccuracies in suppliers' forecasts, at least in the short term.

2.42 Suppliers submit consumption forecasts for such non-commodity costs at regular intervals; these are used to set tariff rates up to 15 months in advance of them coming into effect. However, given suppliers must also submit forecasts for billing purposes and are expected to submit revised forecasts to reflect changes in their portfolio, they could also be exposed to new costs within a couple of months of changes in peak demand.

2.43 Network companies (ie Distribution Network Operators for DUoS charges, and Transmission Operators for TNUoS) are subject to revenue caps set by Ofgem and are only allowed to earn a specific amount of revenue each year through their charges. There are a number of variables which impact network companies' revenues; one of these is if customer actual demand (especially during peak periods) differs from forecast demand. In this event, the total revenue collected from DUoS and TNUoS charges may be above or below the allowed revenue under each network price control. Any mismatch in cost recovery would be carried forward to future periods to ensure network companies recover the correct level of revenue.

2.44 There is a similar mechanism for Capacity Market charges. If suppliers collectively pay more than is required for that year's obligations, the excess is returned to suppliers via the Residual Supplier Amount (RSA) mechanism.

2.45 As a result of these mechanisms, network companies and other charging companies recover the required revenue in the event of an initial under or over recovery. However, as these mechanisms work in aggregate, it is unlikely that they mitigate the impacts of cost diversity across suppliers which may relate more closely to the mix of customer types within a supplier's customer base.

2.46 Overall, the interplay between changes in settlement and how non-commodity costs are structured and calculated is complex. As noted earlier, further analysis and engagement is required to fully understand this relationship and what consequential changes may be needed to the cap. In response to this call for input, we are seeking evidence from stakeholders that clearly sets out what they expect the impacts of MHHS to be. We will supplement this with further engagement.

Analysis of impact on non-commodity costs

2.47 We have carried out a preliminary analysis of the average impact on non-commodity costs, using a cross-market subsample of 20,000 MPANs (electricity meter points) depending on supplier size, from the total demand data we have collected from suppliers. This analysis will be superseded by our detailed modelling once we have robustly validated and aggregated supplier data.

2.48 To understand the impact on non-commodity costs of moving to MHHS, we compared profile classes to actual demand by replacing the demand profile assumptions in the non-commodity costs cap model with a demand profile based on actual demand. We compared the costs associated with the average actual demand profile of profile class 1 and profile class 0 default tariff customers (excluding those on ToU tariffs) against the standard Elexon profile class 1. Profile class 0 customers are those who are already settled half-hourly on an elective basis. We include these default tariff customers in our analysis as they are cap customers charged against the single-rate cap level. To the extent that their demand profile is cheaper to serve on average, suppliers with these customers will already be realising that benefit. For suppliers who have not opted into elective half-hourly settlement, these customers are likely mixed in with profile class 1 customers.

2.49 The weighted average impact across the market is an approximate £0.50 increase in cost per typical customer. The distribution of average impact ranges between an increase in cost of £3.50 and a reduction in cost of £1.10 per customer. This suggests that at least in the short term, the impact across the market will be small on average. However, some suppliers may see somewhat higher costs highlighting some of the challenges with setting one cap across the market. To note, we used the full sample of data to run the supplier specific analysis (based on the subsample of 10,000-25,000 MPANs per supplier and noting this differs to the sample used to calculate the cross market average impact).

2.50 When looking at the cost distributions, we found the 10th percentile cost across the market incurred a reduction of £17 while the 90th percentile resulted in an increase of £16. On this basis, we could see larger average impacts if cheaper cost to serve customers were incentivised to move onto ToU tariffs, leaving more costly customers on the cap.

2.51 Several suppliers have raised particular concerns around the impact of MHHS on non-commodity costs. While we consider the impact across the market will be small on average based on our initial analysis, further engagement is required to understand the dynamics of any expected impacts.

Interaction with the Cost Allocation and Recovery Review

2.52 The Cost Allocation and Recovery Review (CARR) is looking at whether there are fairer and more efficient ways of allocating and recovering energy system costs from consumers, reflecting our duties including those to support net zero and economic growth. This includes varying charges based on the amount of energy used or charges linked to use at peak times.

2.53 Any reallocation of costs between fixed/variable costs or other charges following CARR could affect the distribution of costs across suppliers and different customer groups. We are currently considering the distributional impacts of alternative cost recovery approaches and intend to engage with stakeholders in spring 2026 on our options, analytical framework, and initial findings. We intend for CARR to bring together our reforms on retail pricing and network charging in one coordinated programme, to ensure that pricing reforms remain consistent with the evolution of underlying costs.

2.54 When considering changes to the cap allowances as a result of MHHS, we will need to be mindful of any resulting changes in peak charging or how non-commodity costs are allocated across peak usage.

Impact on customers

2.55 In the short-term, we expect MHHS to have little direct impact on customers. They may start to see a growing offering of ToU tariffs that are more accessible to a wider variety of customers. ToU tariffs have existed for some time; most commonly these have been Economy 7 and Economy 10 tariffs offering 7 hours and 10 hours of cheaper off-peak electricity respectively. The more recent introduction of “smart” ToU tariffs (mostly fixed contract term) are enabled by MHHS and only available for those with a smart meter and those who share their half-hourly data; they allow for greater variation in prices over different time bands.

2.56 In the longer term, completion of MHHS migration, higher adoption of LCTs and more electrification of heat, are likely to result in a greater and more diverse range of tariff offerings in the market. The additional choice of and reliance on technologies may facilitate greater consumer-led flexibility benefitting customers who are able to move their demand, and ultimately helping to keep system costs lower.

2.57 A greater diversity of tariffs and bills is likely to have distributional impacts across customers. If customers with a higher proportion of peak consumption who are able to shift their demand outside of peak periods are incentivised to move to ToU tariffs, they will see a benefit relative to current prices which are set on an average demand profile across all customers. By comparison, customers with a higher proportion of peak consumption but who do not shift their demand may pay relatively higher prices as they incur a greater proportion of costs during peak periods. This could be through a more expensive single-rate tariff reflecting a greater cost to serve or through a ToU tariff in not realising benefits of shifting demand. Customers who start off with a flatter demand profile may not be able to shift much of their demand but would still likely benefit from moving to ToU tariffs that reward their flatter demand shape.

2.58 There are different types of customers who do not shift their demand. They include both those who can but choose not to shift their demand and those who are unable to shift their demand. The weight we would place on impacts across these two groups may differ when considering consumer protection.

2.59 A further distributional implication between customers shifting or not shifting demand is that if more default tariff customers with a flatter demand shape left the cap over time, this would gradually increase the average "peakiness" of the remaining default tariff customers and therefore the average cost to serve them.

Case for change

Impact on the cap

2.60 There are several impacts on the cap from the changes in settlement; from these we can infer that changes to the cap will be required.

Changes in data inputs

2.61 The move away from profile classes and to the use of both actual demand data and the LSS impacts the data inputs used in the cap. The cap currently uses a breakdown of quarterly demand by profile class to allocate charges across several cost components (for example weighting quarterly wholesale products in calculating the wholesale cost index).

2.62 To the extent that profile class information will no longer be available in future, we will need to find a data source that serves as an appropriate alternative. The data source will need to be regularly available for update.

Diversity in costs

2.63 As discussed earlier in this chapter, we expect the diversity of costs between suppliers may increase. The speed at which this happens will depend on suppliers' commercial strategies as well as how quickly customers adopt ToU tariffs and respond to price signals. Under the Act, we cannot set a separate cap level per supplier. We account for this by setting the cap based on a notional efficient supplier that is representative of the market. With greater cost variation between suppliers, it may become more challenging to define a notional efficient supplier. We consider that the demand shape of a supplier's customer base may be, to a degree, within its control as it can be impacted by the supplier's commercial strategy. However, there is likely to be less direct control, at least in the short term, so long as take up of ToU tariffs and consumer-led flexibility more generally remain relatively low. In the longer term, as the market evolves, we may consider a supplier's ability to encourage their customers to shift demand as a part of efficiency.

2.64 Continuing to set the cap based on the costs associated with an average demand profile could risk increasing the gains and losses suppliers make on their own position relative to the cap level. Cost recovery risks for an efficient supplier could undermine investor confidence and negatively impact the investibility of the sector. When considering investability, we must keep in mind that many customers are facing financial pressures at present. However, we also consider that it is in customers' interests that the retail market is able to attract the investment required to provide them with good service, innovative products and resilient suppliers.

2.65 An investable market supports default tariff customers in two main ways. First, an investable market improves suppliers' financial positions (relative to an uninvestable market). This increases their ability to make investments, including through attracting capital from investors (suppliers may also make investments from retained earnings). These investments can benefit default tariff customers, for example by improving customer service.

2.66 Second, the attractiveness of the market affects incentives for suppliers to enter the market and grow, and therefore the degree of competition. Competitive pressure can drive service improvements, innovation, and customer engagement. Increased engagement can support customers to move to fixed tariffs which are cheaper than the cap. Competition can also help to support increased engagement, as suppliers seek to attract and retain customers. This can help customers to move to fixed tariffs which are cheaper than the cap.

Interaction with flexibility

2.67 The current cap may risk acting as a barrier to greater consumer-led flexibility. Under the single rate cap design, default tariff customers pay the same rate for electricity regardless of when they use it. This means that "peakier" default tariff customers who are settled half-hourly, like other customers on single rate tariffs, will be sheltered from higher bills following MHHS, because they will not be exposed to higher peak prices.

2.68 While this approach may diminish the incentives for customers who can shift their demand, the cap does provide a degree of protection to those that are unable to. In that respect it provides a similar effect to single rate fixed tariffs in giving a predictable price that customers can expect to incur for their energy usage.

2.69 As the number of fixed ToU tariff offerings in the market grows along with consumer take-up, it is important to ensure that there are adequate protections in place to support consumers as they engage with them. This includes engaging with suppliers to ensure that there are appropriate default tariff arrangements for customers who do not select a new tariff at the end of their fixed term contract ToU tariff.

2.70 Alongside appropriate default tariff arrangements, we also need an appropriate ToU variant for the cap. We do not think the absence of one would currently deter customers from adopting ToU tariffs. However, we consider that setting the cap at an appropriate level for ToU customers is important to ensure they pay a fair price and retain some incentive to use energy outside of peak periods.

2.71 Finally, allowing an efficient supplier to recover its costs is important to enabling innovation in the market. We do not think that cap in and of itself hampers the introduction of ToU tariffs in the fixed market. However, we understand the risk that if the cap is set too low and risks supplier cost recovery, there may be less incentive for suppliers to compete for customers by offering ToU tariffs. Overall, we seek to facilitate a move towards greater consumer-led flexibility, but we consider it the cap's core role to ensure SVT and default tariff customers are paying a fair price.

Direction of travel

2.72 The impacts of MHHS on suppliers will develop over time, but broadly we expect it will increase a supplier's uncertainty about its costs of serving default tariff customers, and it may increase diversity of costs across suppliers. We consider the cost impacts could be significant over the longer term, coupled with greater cost variation between suppliers as customers change their usage and move across different products.

2.73 Overall, the timing of the longer-term impacts across the market are uncertain. There are factors that will impact the costs suppliers and customers face such as the peakiness and volatility of wholesale prices and the way in which network costs are recovered over peak demand periods. Additionally, there are several factors that affect the level and shape of demand more generally such as the level of data consent and smart meter penetration, adoption of ToU tariffs and policy changes to encourage demand side response.

2.74 These uncertainties are not uniform across different types of customers and therefore it's possible that the landscape changes in different ways for cap customers relative to the average customer. For example, suppliers' commercial strategy and customer incentives will play a big role in how the market may develop in future.

2.75 We do not consider that it is feasible to wait until the impacts of MHHS become clearer before starting to make changes to the cap. This could risk financial pressures on suppliers which could start to affect resilience, ultimately creating a negative impact on customers.

2.76 Given the impacts on the cap and the uncertainties in how quickly the market will change, we propose that the following direction of travel is appropriate:

- Approach to setting the cap – The cap should follow market dynamics rather than trying to project and pre-empt them. However, this will require a staged incremental approach in how we set the cap as the market evolves over time rather than waiting for the market to change completely and then updating the cap. We consider that a clear approach and framework that follows the market dynamics is important.
- Cost diversity – When updating the cap demand profile to account for MHHS, we may need to consider the impact of greater cost diversity and lagged cost

recovery from setting demand on an ex-post basis. We will consider these factors when deciding how we benchmark a demand profile.

- Flexibility incentives – Alongside the single rate cap level, a ToU cap variant that reflects benefits to those that are able to change their usage pattern is necessary. This is key to ensuring the cap does not become a barrier to greater levels of voluntary consumer-led flexibility.

2.77 We do not anticipate large immediate effects that would risk the resilience of the market. However, given the potentially significant cost impacts over the longer term, we consider it is important that we start to adapt the cap now to these emerging pressures and opportunities. As noted above, we see changes to how we set the cap needing to be applied in incremental stages.

2.78 Our analysis outlined suggests that the average cost to serve default tariff customers is not going to materially change over the coming year. Furthermore, we consider that the electricity wholesale risk allowance (1% of the electricity wholesale index) and our recent cap methodology decisions to improve cost recovery across allowances will provide a buffer against any small immediate variances in average costs across suppliers before we implement our changes to how we set the cap. Therefore, given MHHS migration is ongoing through 2026 and the full suite of settlement changes are not expected to apply until the end of 2027, we expect any initial changes to how we set the cap to be in place from 2027.

2.79 Through engagement, stakeholders have raised greater concerns regarding the impact on non-commodity costs. While our analysis implies a small impact in the short-term, if further evidence is provided to suggest that MHHS will have a more significant impact on non-commodity costs we may consider it appropriate to make a change to the cap methodology sooner. We are actively engaging with stakeholders to build a view of when these changes may happen and what consequential changes we may need to make to the cap.

Detailed modelling and analysis

2.80 Our current assessment is based on preliminary, high-level analysis. While we have collected extensive supplier demand data, we have not yet undertaken the detailed cost assessment and scenario modelling needed to reflect future market conditions. As a result, the analysis in this chapter is indicative only. Further modelling will be required and will supersede this analysis, informing the trade-offs between the policy options set out in the next chapter. There are several areas of uncertainty where we do not hold strong evidence and further work will be required.

2.81 We currently lack sufficient evidence on how future demand profiles may evolve. In particular, we need to establish how the rollout of LCTs, such as EVs, alongside consumers' willingness and ability to shift consumption will affect the shape of demand. While ToU tariffs may enable greater consumer-led flexibility, we do not yet know the likely scale of uptake or behavioural response. Further analysis and information gathering is needed to assess how different demand outcomes would affect suppliers' costs across customer groups, including default tariff customers.

2.82 A clearer understanding of how the continued rollout of smart meters and their use for settlement purposes by suppliers will affect future aggregate settlement profiles is also key. As more customers are settled using their half-hourly demand data, the proportion of suppliers' customers settled using half-hourly data and those settled using the LSS will change. We need this information to determine how this transition may alter the average half-hourly demand profile faced by suppliers for their default tariff customers settled on a non half-hourly basis, and whether this has implications for how demand profiles should be set in the cap.

2.83 On the supply side, we lack robust evidence on how changes in the generation mix will affect wholesale price patterns, particularly daily and intraday prices. Increased deployment of intermittent renewable generation may lower prices at certain times but increase volatility across the day. Further analysis is required to understand how these changes translate into wholesale cost risk for suppliers under MHHS. We will need clear scenarios of what prices the market may see in future. We intend to carry out price analysis to inform a range of scenarios but are mindful that stakeholders may already have their own assumptions, which we would be interested in understanding.

2.84 Finally, we will need to understand how evolving demand and supply dynamics interact to shape wholesale prices over time. In particular, we need to assess whether future conditions could intensify existing peak pricing patterns or shift cost pressures to different times of day, alongside how this may widen differences in costs to serve across customers.

2.85 Addressing these evidence gaps will require further modelling and scenario-based analysis, developed through continued engagement with stakeholders. In some cases, it might require additional data gathering. We seek views and evidence on any of these topics via responses to this call for input.

Chapter 2 questions

Q1. Do you agree that the short-term commodity cost impacts relating to default tariff customers are small on average but that the longer-term dynamic impacts could be much greater? When do you expect material impacts to take effect?

Q2. What are your views on how non-commodity costs relating to default tariff customers could change due to MHHS? Please be specific on which cost you are referring to and explain where you agree/disagree with our assessment.

Q3, Are there any specific groups of default tariff customers we should think about distributional impacts for when trying to understand the impacts of MHHS across the market?

Q4. Which uncertainties are best captured through scenario-based analysis, and what scenarios do you consider most relevant for assessing future costs under MHHS?

Q5. How might future changes in demand and supply dynamics affect the timing and severity of peak prices, including the potential for pinch points to shift away from the traditional evening peak period?

Q6. How might the rollout of LCTs (such as EVs and heat pumps) and increased consumer-led flexibility change the aggregate and customer-level demand shape over time?

Q7. At what speed and scale do you expect ToU tariffs to influence customer consumption behaviour, and how differentiated do you expect demand profiles to become across different groups of customers?

3. Options assessment

In this chapter, we set out the key optionality for the approaches we intend to proceed with. We consider how we could set the allowances and the impacts those choices may have.

3.1 We consider that there are three broad options for changing how we update the cap:

a) incremental reform, where we retain the current cap structure and update the single-rate and multi-rate or ToU cap levels

b) move all single rate default tariff customers onto a ToU default tariff

c) structurally change how we set the wholesale allowance (for example by setting caps for each half-hourly settlement period)

3.2 Options (b) and (c) would involve more significant changes to how we set and operate the cap. At this stage, we consider it appropriate to proceed with option (a) given that the MHHS migration is still ongoing and we expect a gradual increase in consumer-led flexibility over the coming years.

3.3 As noted in Chapter 1, we have set out our vision for consumer-led flexibility and the steps we have taken so far. This call for input forms part of our approach to facilitating consumer-led flexibility rather than the full answer. It provides an initial step in reforming the cap and a clear direction of travel on which we can build as the market develops.

3.4 In the future, we may wish to further consider options (b) and (c). We outline our initial assessment below. Given the significant change entailed and number of customers who would be impacted, we would need clear analysis of the distributional impacts across different groups of customers to support our future decision making.

3.5 While we are not pursuing development of these two options currently, we are not ruling them out in the future. Our immediate focus does not prejudge our approach to these approaches which may become more appropriate in future as the market evolves, ToU pricing becomes more widespread and we develop our policy on consumer-led flexibility. However, at this stage we are focusing on more immediate incremental reforms to the cap design.

3.6 Option (b) (moving the cap onto a ToU basis for all default tariff customers) would increase opportunities for customers to benefit from using electricity when underlying costs are lower. It could also mitigate the impact of cost diversity between suppliers' customer bases.

3.7 However, such an approach would risk forcing customers onto unfamiliar tariff structures before they are ready. It may also not lead to significant or sustained flexibility benefits, as customers on default tariffs are more likely to be disengaged. Furthermore, customers on default tariffs are more likely to be on lower incomes, and it may therefore be harder for them to afford smart technology to help them flex their demand. In addition, the smart meter rollout is ongoing, and customers with single rate traditional meters would not be able to have a ToU tariff. Careful consideration of the distributional impacts and necessary customer protections would be needed before adopting option (b).

3.8 Instead of mandating ToU pricing for all default tariff customers, we could only mandate it for specific customer groups, such as EV owners. This would be on the basis that these customers may drive higher system costs if their demand was concentrated at peak times. This could improve cost reflectivity and ensure that these customers pay for the system cost of their consumption patterns. However, there could be significant practical challenges, including the reliable identification of customers with EVs.

3.9 Option (c) would involve significant structural changes to the cap, for example, setting wholesale allowances for each half-hourly settlement period. This would avoid having to set multiple cap levels for different tariffs, as the approach would be flexible enough to cover all types of default tariff. It could therefore reduce the risk of the cap acting as a barrier to innovation on the design of default tariffs. However, this option would take time to design and implement. It could also make it more complicated to reassure default tariff customers that they were still protected.

3.10 Reflecting our focus on more immediate incremental reforms to the cap design, and our direction of travel set out in the previous chapter, we consider we need a cap that sets (1) a single-rate level based on default tariff customers' demand profile and (2) at least one ToU cap variant that appropriately reflects the benefits of changing usage. Within these two cap levels, we will need to consider how we account for a potential increase in cost diversity across the market.

3.11 Over this chapter, we discuss the options and choices behind designing the single-rate and ToU cap levels. The optionality covers:

- how we benchmark a demand profile for setting the wholesale allowances
- whether the demand profiles need to vary across cap parameters
- how many ToU cap variants we want to set to cover different types of customers and technologies (for example EV charging)
- how prescriptive we want to be when setting the ToU cap variant, including the unit rates and time bands they apply to
- the approach for updating the demand profile used to set the allowances

3.12 We focus discussion on setting demand profiles to reflect different groups of customers. In aggregate it is the profile against which suppliers purchase energy for a group of customers. A demand profile is also a key input to setting several of the non-commodity costs, such as Capacity Market charges, and wholesale allowances such as the wholesale index, shaping and imbalance. We don't cover a review of the methodology for these allowances at this stage, but we intend to discuss this in future rounds of engagement.

Setting a flat or static cap level

3.13 Currently, most (over 90 per cent) default tariff customers are served by the single-rate cap level for electricity. As smart ToU tariffs gain greater traction with the introduction of MHHS and greater use of LCTs, we expect some customers who can make greater savings may move away from the default tariff cap. As these customers who can load shift or have flatter demand profiles move off the cap, the actual half hourly average demand profile of a cap customer may not reflect the current assumed demand profile (profile class 1) used to set the single rate allowance. Additionally, MHHS may expose suppliers to different levels of cost depending on its customer base, which creates challenges given we must set one cap level across suppliers. Both factors suggest that we may require a different approach to setting the wholesale allowances in the cap.

Setting the demand profile

3.14 We set the cap to reflect a notional supplier's efficient costs of serving its default tariff customers. Historically, it has been sufficient to use the notional profile classes to reflect the costs of serving customers on the cap. Even though the demand data includes customers on fixed term tariffs, not just those on the cap, it still broadly reflects the costs of serving them. However, to reflect notional efficient costs in setting the wholesale allowance going forward, we consider that it may become appropriate to set the demand profile based only on default tariff customers' demand.

3.15 Setting a default tariff customer specific demand profile means that the cap will continue to track the costs suppliers face for serving default tariff customers, particularly if customers with a flatter demand shape move off the cap and onto fixed tariffs. We expect this may happen as tariff diversity increases with MHHS and with growing take-up of LCTs.

3.16 This approach is not without challenge. Currently, for the purposes of calculating imbalance positions, default tariff and fixed tariff customers are treated equivalently (ie both sets of customers are measured against the same profile class without distinction of tariff type). To the extent that the demand profile for default tariff customers becomes relatively more costly over time, setting the cap based only on a default tariff demand profile would expose cap customers to a higher price. We anticipate that initial differences will be small, at least in the short term while take-up of ToU tariffs is relatively low.

3.17 If ToU fixed tariffs are priced to attract default tariff customers with flatter demand profiles and some of these customers move away from the cap, the average demand profile for default tariff customers is likely to increase in peakiness. In a scenario with significant churn away from the cap, this could have a significant impact on default tariff customer bills. However, such changes are likely to be gradual and emerge over the medium to long term. This is because we do not expect significant numbers of customers to be incentivised by ToU tariffs to switch away from the cap in the short term.

3.18 Furthermore, there are different meter arrangements for different groups of customers that would be settled against different demand profiles. Data specifically on default tariff customers and more broadly on the parameters we use to set different cap levels will not be available in each case. Customers could broadly be in the following three sets of circumstances:

- those with smart meters who have consented to share their half-hourly demand data and have been migrated to the new settlement arrangements are settled half-hourly and on their actual demand. We will have sampled data that will be split by tariff type for these customers
- customers who do not have a smart meter or have not consented or have opted out of sharing their half-hourly demand data will be settled against the appropriate LSS on a non-half-hourly basis. The LSS profiles are not split by tariff type. We expect this group of customers to reduce as consent increases and the smart meter rollout nears completion
- customers who have a smart meter and who have consented or have not opted out of sharing their half-hourly demand data, but who have not yet been migrated to the new settlement arrangements, will continue to be settled against the current assumed profile classes (also on a non half-hourly basis). We expect this group will fall to zero once MHHS migration has completed in 2027

3.19 Overall, we do not intend to set separate cap levels for half-hourly and non half-hourly settled customers. Therefore, we would need to consider whether we set a single demand profile for both sets of default tariff customers based purely on half-hourly settled default tariff customers. This may be more appropriate in future as data consent increases but may risk not reflecting costs in the shorter term. Such an approach would allow us to set the cap purely based on default tariff customers, as it would not rely on the LSS.

3.20 Alternatively, we could use either a combination of half-hourly data and the LSS to reflect an average across both groups of customers, or the LSS profile alone. The former approach would be a mix of default tariff customers who are settled on their half-hourly demand and all customers settled non half-hourly against the LSS profile. To combine these two profiles, we could attempt to weight it by the relative proportions of those who are and are not settled half-hourly.

3.21 The LSS demand profiles are based on average half-hourly demand data for different groups of customers who are settled on their actual half hourly demand. Therefore, we do not anticipate issues in incorporating this data to set the demand profile.

3.22 Using the LSS profile solely would create an easier update process that would be less dependent on our own data collection. However, it would limit our ability to set a default tariff customer specific profile and to split the profile by cap parameters. Therefore, we would have to consider whether to adjust the LSS profile to better reflect default tariff customers and any differences that arise by cap parameter based on the supplier data we have collected.

3.23 Our detailed modelling will provide an indication of the types of scenarios that could outturn, which will inform whether we consider the balance of risk for this approach is appropriate across default tariff customers.

Benchmarking demand and varying by cap parameter

3.24 In the section above, we talk about setting a demand profile for default tariff customers based on the average. However, with greater diversification in tariffs and customer profiles, as well as suppliers being exposed to the actual demand profile of their customers, we may see a greater variation in wholesale costs across suppliers relative to their customer bases.

3.25 As discussed earlier, we have to set one cap across the market, meaning the cap cannot account for variations in individual suppliers' costs. This creates a risk where there is greater variation in efficient costs across suppliers. The diversification in customers' electricity usage across suppliers increases the risk that the spread of costs increases, meaning the average trends further away from the extremes.

3.26 Where a supplier has customers that are peakier than average, it would incur greater costs. The opposite would be true for a supplier that has less peaky customers than average. Our initial analysis suggests that the spread in demand across most suppliers is currently small. For example, the difference in the average wholesale cost to serve of a typical customer for most suppliers was between ± £1. Furthermore, the weighted average difference in cost between the 10th and 90th percentile cost to serve customers across suppliers was £22.25. This is equivalent to approximately ±5% of the average wholesale commodity cost to serve under the cap. However, the spread of costs may increase in future as the flexible practices in the market develop. This could create investibility and resilience challenges for certain groups of suppliers.

3.27 Additionally, through stakeholder engagement, a few suppliers have said that forecasting customer demand will become a greater challenge in future. To understand the impacts, it is important to separate the static and dynamic effects. The static impacts are those driven by the technical changes in settlement approach brought about by MHHS. The dynamic impacts include changes in consumption behaviour by consumers who are settled on their half hourly demand to take advantage of lower costs (for example by adopting ToU tariffs). These static impacts enable rather than directly cause such dynamic impacts. We consider these dynamic impacts are more likely to occur in the longer term.

3.28 In the short term, the move to using actual demand to settle suppliers could create a greater risk of forecast error, particularly for customers that they have recently had a smart meter installed. This is a static impact which creates cost uncertainty as we expect demand patterns to remain unchanged in the short run. We expect these impacts to reduce as suppliers grow accustomed to forecasting actual demand.

3.29 In the long term, consumption trends may become less predictable leading to demand uncertainty as customers respond to price signals. A greater proportion of energy being sourced from renewable generation may also lead to a potential increase in price volatility. This is another example of dynamic impacts and depends on several factors such as the level of consumer-led flexibility response.

3.30 To mitigate against these areas of uncertainty, we will need to consider the level at which we benchmark the demand profile for default tariff customers. Reflecting the average level of peakiness would reflect default tariff customers' cost in aggregate but could lead to some suppliers under-recovering their costs and others over-recovering depending on the degree of cost variation between suppliers in future. Alternatively, we could consider setting an above average level of peakiness for the demand profile which would provide some resilience to suppliers with customers that are more costly than average. The data we have collected gives us an indication of the distribution of demand profiles over a sample of customers.

3.31 Another way to mitigate cost recovery risks is to reflect differences in groups of customers that are identifiable and recognised under the cap (payment type, meter type, fuel type and region). For example, in the operating cost allowance review, we found Standard Credit customers are more costly to serve than Direct Debit customers. Reflecting these differences between groups reduced the risk of a supplier with an above average proportion of Standard Credit customers not recovering its efficient costs.

3.32 We may consider taking a similar approach to setting the wholesale allowances if our analysis determines that there are identifiable groups of customers that have peakier demand profiles. However, we will need to be mindful of the impact such an approach would have on those customer groups' bills. We expect our cost modelling will allow us to quantify the impact on both customers and suppliers.

3.33 Our approach depends on how clearly we can identify different consumption patterns across customer groups. Overall, we will need to balance reflecting these patterns directly in the cap (to the extent that it is possible) and using a more accommodating demand profile that covers all customers whilst reducing the risk of under recovery for suppliers whose customers differ from the average.

Update approach

3.34 As we outlined in the case for change, we expect the market and how customers engage with energy usage to change as LCTs become more prevalent. This means that the average demand profile is unlikely to remain static over time as customers move between products and technologies.

3.35 As part of our review of the wholesale allowance, we will need to consider how frequently we review and update the demand profile and associated elements of the wholesale allowance. Currently we update the wholesale index every quarter, but we have not reviewed the approach or data used to set the shaping and imbalance allowance since we introduced the cap. Alongside this, the profile class data used to set demand weights across several allowances within the cap is updated annually.

3.36 We expect any changes in demand to be gradual over time. Therefore, we consider the minimum time between demand profile updates would be one year, with two years being more appropriate. We consider any process for updating demand in the cap should be a mechanistic data update rather than a review of the methodology by which we set the wholesale allowances. It's likely that an update would be based on supplier data we collect on an ongoing basis, similar to what we have collected to carry out our detailed modelling for this review. However, as noted earlier some design choices such as using the LSS as the demand profile would reduce the reliance on supplier data and increase transparency.

3.37 In setting and updating a demand profile, we will also need to consider whether we can standardise the demand profile to remove intra-year impacts and if so how. This is particularly important for when we initially set the allowance and have a limited amount of historical data. If we do not normalise the data, there may be a risk that we capture demand trends relating to things like unseasonal weather or exceptional weather events. The shaping allowance in the cap is currently calculated on a 10-year normalised view of demand. Standardising the demand profile may be particularly challenging as we have at most two full years of half-hourly data rather than a longer time-series.

Setting a ToU cap variant level

3.38 We already have a ToU cap variant for customers with multi-register electricity metering arrangements who are settled against profile class 2. This cap variant was primarily designed for customers on traditional meter with tariffs that have more than one unit rate (such as Economy 7 and Economy 10). It also covers other customers on more recent smart ToU tariffs. However, it's unlikely that the current multi-register level of the cap will continue to reflect the cost of serving customers that may benefit from such tariffs. In addition, there are aspects of the multi-register cap that do not currently reflect the benefits of off-peak consumption expected from Economy 7 and other such tariffs. We consider that further work is needed to reform the multi-register level of the cap and develop a suitable ToU default for the future market.

3.39 It will become increasingly important to have an appropriate ToU cap variant as take up of ToU tariffs increases. As we explain in more detail below, customers coming to the end of a fixed term ToU tariff who do not select a new tariff should be defaulted onto the multi-register level of the cap. A ToU cap variant therefore needs to be cost reflective to be an appropriate tariff for fixed ToU tariff customers to default onto. This is in part to ensure that the right level of protection remains but also to ensure we are considerate of the necessary benefits and incentives for consumer-led flexibility.

3.40 Several important considerations involved in establishing the single rate cap are equally relevant when determining the ToU cap variant level, such as setting and benchmarking the demand profile and the update approach. In addition to these factors, the following outlines specific design considerations related to determining the ToU cap variant level:

- the number of ToU variants we set for the cap;
- how prescriptive we set the unit rates and time bands;
- default tariff arrangements;
- how we set the demand profile for the ToU cap variant.

Number of ToU cap variants and unit rates

3.41 In setting a ToU cap variant, we can decide how prescriptively we set the design across three key parameters:

- the number of variants we set
- the number of time bands within each variant
- how strongly we specify the unit rates and time bands they apply to.

3.42 Setting a greater number of ToU cap variants and specifying the unit rates would lead to a more prescriptive set of allowances, which would give greater control of outcomes and incentives. However, it would provide less flexibility to the market to determine how best to price default tariffs and develop products that are in consumers' interests (for example what sort of differences between different consumption time bands would be needed to incentivise consumer-led flexibility).

3.43 Currently, the cap has one multi-register level against which we measure compliance of any tariffs with more than one unit rate. As with the single rate cap, the multi-register level of the cap does vary by the different cap parameters such as region and payment method. However it does not set different demand profiles to calculate the wholesale index or shaping allowance for these other cap parameters. This gives suppliers the flexibility to determine how best to structure multi-rate tariffs under the cap. However, to note, within the shaping allowance the multi-register cap level assumes the same demand profile shape (ie customer usage patterns over settlement periods) as the single-rate cap level. This means that despite suppliers being able to set the structure of the tariff, the underlying costs are partially reflective of single-rate customers. Therefore, the multi-register cap level doesn’t capture the full benefits of profile class 2 customers having greater off-peak usage on average (see Appendix 1).

3.44 As the market develops, we will need to think carefully about the different types of users we may need to reflect in the cap. We will also need to consider whether customers on traditional meter Economy 7 tariffs who are settled against a different LSS profile are covered by a central ToU cap variant or require a specific cap level. Overall, we will need to bear in mind that we are considering the cap specifically, rather than tariff designs for the market as a whole.

3.45 When deciding how many ToU cap variant levels to set, there’s a balance between having a greater reflection of costs by incorporating different types of users and increasing the complexity of setting a cap by having a greater number of cap levels. We must carefully consider what kinds of incentives are appropriate, balancing customer protection with the need to reflect price signals to different groups. The level of complexity that is appropriate for a ToU cap variant will require careful thought and consideration. While customers may be defaulting onto the ToU cap variant from complex ToU fixed term contracts with potentially multiple time bands and flexible prices, such complex pricing structures may not be appropriate for the ToU cap variant.

3.46 In principle, we consider we should limit the number of variants we set to ensure they remain understandable and easy to navigate for customers and administering the cap continues to be manageable. To do this, we consider setting one central ToU cap variant is appropriate to reflect costs across different types of customers.

3.47 There may be certain cases in which setting an additional ToU cap variant to cover a particular group of customers would be beneficial in reflecting costs or providing greater flexibility incentives. Where the underlying demand profile differs for a specific group of customers, we would need to set a specific variant with an associated demand profile to reflect their underlying usage patterns and costs. This would ensure that the cap level more appropriately reflects any benefits or costs of that specific usage for customers and would reduce any cost recovery risks for suppliers that have an above average proportion of that customer type.

3.48 When considering flexibility incentives, we may want to set a tariff that incentivises usage that is beneficial for the energy system. If we were to adopt this approach we would need to be particularly mindful of the default tariff arrangements and customer impact. For example, we may define a cap level that is more expensive for a group of customers than other ToU cap variants based on their usage patterns with the aim to incentivise usage during specific periods.

3.49 If the underlying demand profile does not differ but we only want to influence consumption incentives, we could use the same demand profile with more prescriptive unit rates. Any such specific ToU cap variant would require clear identification of the relevant customer and associated demand profile (as we note below), as well as appropriate default tariff arrangements, to ensure customers are on tariffs that work best for consumers and the system.

3.50 One example of where we may consider setting such a specific ToU cap variant is for EV customers. EV customers charging their vehicles during peak periods put an additional load on the system and potentially increase costs for all customers. Setting a separate ToU cap variant for these customers would allow us to put stronger price signals in place for them to incentivise charging during off-peak periods.

3.51 A key challenge with setting an EV specific ToU cap variant is identifying which default tariff customers own EVs. It would be clearer where a customer defaults from a fixed EV tariff to the cap. However, in the absence of an asset register allowing suppliers to identify EV owners, an EV customer may still end up on the single rate cap if they have not defaulted from a ToU tariff.

3.52 Suppliers could analyse customer demand shapes to try to identify which customers may own an EV. However, attributing a particular demand shape to EV owners could capture other customers with a similar demand shape who do not own an EV. Mistakenly placing these customers on an EV variant risks sending inappropriate price signals for flexibility and undermining consumer-led flexibility. For example, we may want to price the EV variant to discourage EV charging during peak times. If we did so, customers with a different LCT to an EV who had been placed on this tariff would face these same price signals when we may want to incentivise different usage of their particular LCT.

Level of prescription

3.53 Alongside considering the number of ToU cap variants we set, we also need to consider whether we want to be prescriptive in setting the level and number of unit rates for any ToU cap variants. A more prescriptive approach would facilitate setting clear flexibility signals underpinned by a particular policy direction. It could also boost consumer trust and potentially take up of ToU tariffs more generally. Some customers, especially those who are more uncertain about ToU tariffs, may be more likely to switch to a fixed term contract ToU tariff if they know that they are protected by a ToU default set in a prescriptive way under the price cap.

3.54 Additionally, specifying the unit rates would reduce any potential risk of gaming, where the mix of unit rates could be set in a way that is more favourable to a supplier rather than the customers covered by the tariff. However, we consider compliance checks and clear guidance can reduce this risk rather than resorting to a more prescriptive approach immediately.

3.55 More generally, we consider that a prescriptive approach would reduce the freedom a supplier has to price its own rates based on the assumed demand splits of its customers for a given tariff. As with setting the number of ToU cap variants, we do not think being prescriptive in setting the unit rates and the time bands they apply to is generally preferable. There is a greater risk that there may be certain groups of customers that lose out as a result (for example where their usage pattern does not match the overarching group used to set the rates). However, there may be certain edge cases in which setting direct incentives may help to achieve a desired outcome (we cover one such example above for EV customers where we could set rates to incentivise greater night charging/disincentivise day charging).

Default tariff arrangements

3.56 Default tariff arrangements set out the obligations suppliers have regarding customers whose fixed-term tariffs expire and who are subsequently moved onto default tariffs, subject to the cap. In our latest issued guidance to suppliers, we set out that at the end of a fixed tariff, the supplier should move a customer to the equivalent default tariff. In the case of fixed term ToU tariffs, the customer should be moved onto the multi-register level of the cap.

3.57 We are currently engaging with suppliers on their requirements as set out in the licence on this area. Our interpretation of SLC 22C.7 is that when a fixed term tariff expires and a customer takes no action, the supplier must default the customer onto the Relevant Cheapest Evergreen (or Relevant Fixed Term Default) tariff that corresponds to their Relevant Meter Type. Meter types are determined by a customer's contractual arrangement, for example a single rate (category A meter) or ToU (category B to E meter, depending on the type of ToU tariff), and not by the meter's technical capabilities. Therefore, under SLC 22C.7, customers on a single rate fixed term tariff should be placed onto a single rate default tariff, and customers on a ToU fixed term tariff should be placed onto a ToU default tariff. If suppliers have more than one relevant tariff, customers should be placed on to whichever is the cheapest relevant evergreen tariff for them based on their estimated annual consumption. We consider this approach works alongside any changes to the wholesale allowances.

3.58 In general, the fixed market will remain as an option for customers to move around if they feel they are not on a tariff that suits them and seek savings relative to the cap. Overall, customers can see greater savings by moving to fixed tariffs as they are usually cheaper than the cap. The cap should not stop customers moving onto fixed tariffs. However, clear default tariff arrangements are important to support customers as they move between tariffs and enable incentives that benefit the system. A clear approach will ensure that a customer is able to seek the right level and arrangement that is suitable for them.

Setting a demand profile

3.59 One key challenge in setting the ToU cap variant is there may not be a clear profile that reflects all customers that would be on, or benefit from, ToU tariffs, particularly as the market develops and there is greater variation between customers. Unlike the non half-hourly settlement process where the profile class 2 demand profile has been used to estimate the cost of customers with restricted meters, customers will instead be settled against their actual demand. As a starting point, there are a few different options we could consider for constructing a demand profile for the ToU cap variant.

3.60 We could use the same demand profile as the single rate cap level where this reflects the average (or above-average) consumption profile of default tariff customers, including those settled half-hourly. The key difference would be that suppliers would be able to price tariffs with multiple unit rates, when averaged with the consumption associated with those periods, complied to the cap level – similar to how the current multi-register cap works.

3.61 The main issue with adopting the same demand profile between single-rate and ToU customers is that it is likely to undervalue the benefits for ToU customers who typically have a flatter demand profile. When we control for total consumption, we expect fixed-term ToU customers who default onto the ToU cap variant to be cheaper to serve than single-rate default tariff customers, mainly because they tend to be less peaky. This difference is likely to grow over the longer term as tariff diversity increases and incentives for consumer-led flexibility strengthen. However, it is likely that multi-register customers would continue to have higher levels of electricity consumption as they are more likely to use electricity for heating or LCTs and therefore would magnify any impact on supplier costs. Furthermore, the cap is an upper limit on the level a supplier can charge its customers and therefore suppliers are able to price the ToU cap variant below the cap level where customers are less costly to serve.

3.62 This approach could result in the ToU cap variant being set at a higher level than if we set a specific demand profile. However, it may partially mitigate the risk of rising costs for customers who are unable to shift their demand and therefore remain on the single-rate default tariff.

3.63 If we wanted to set a different demand profile for the ToU cap variant, there are a few initial alternative options we could consider. We could use the single-rate demand profile as a starting point and adjust it to be more reflective of ToU customers. A way of achieving this could be to estimate and adjust for the impact LCTs will have on demand.

3.64 Alternatively, we could adopt an approach that characterises default ToU customers by reference to consumption profiles that exhibit relatively high levels of off-peak usage and comparatively limited demand during peak periods, drawing on characteristics observed for certain LCT customer groups. This could be informed either through the application of existing profiles with these characteristics, or by inferring an appropriate representative profile through a clustering analysis of consumption patterns, identifying a group of customers whose behaviour is consistent with greater utilisation of off-peak periods. This approach could provide a greater level of cost reflectivity and build in better incentives for suppliers to encourage default ToU customers to shift demand to off-peak periods.

3.65 The challenge with such an approach is that it would introduce a higher level of judgement on how we set a single measure that reflects all default ToU customers and would be underpinned by complex analysis. There may also be variation across different types of ToU customers, which could increase as take-up of LCTs increases in future. For example, customers with an EV or battery storage may be more likely to have a higher night usage, whereas a customer with just a heat pump may have more uniform usage across the day.

3.66 A potentially simpler approach would be to use a profile that is constructed based on profile class 2 and ToU customers from our current data set. However, we would need to be mindful of our ability to update such a profile, particularly regarding whether we can maintain a consistent view of which customers used to be categorised as profile class 2 once the profile classes are no longer in use.

3.67 Overall, setting a demand profile for ToU customers is a key aspect of this review. We expect to engage stakeholders further on the topic and welcome any views on options, especially any not covered in this call for input.

Other options

3.68 Through our stakeholder engagement, a few suppliers mentioned an increased risk of forecast error noted earlier in this chapter. One supplier suggested we set a structured ex-post framework that would have trigger points for considering whether suppliers' shaping and imbalance costs were higher than the previous quarter's cap allowances and carrying out a true-up if so.

3.69 We are not minded to define such a framework for the wholesale allowances. Forecasting demand remains a core aspect of suppliers' business activities, and they have a degree of control over how they purchase energy to meet their customers demand and shape their contracts.

3.70 Moving risk to customers in this instance may reduce incentives for suppliers to accurately forecast demand. We have a process in place by which to review deviations between efficient costs and allowances that are systematic and material. We have used this approach previously to make adjustments in the cap for additional wholesale costs. We expect such approach would be appropriate if there were to be a material divergence in costs and the allowance which met our test. This would allow us the flexibility to exercise our regulatory judgement on where we considered an adjustment would be appropriate. We do understand the importance reconciliation can play in reducing cost recovery risks. However, such mechanisms would need to be considered on a principle basis relative to how we set the cap more generally.

Chapter 3 questions

Q8. Do you agree with our intention to proceed with incremental reform, retaining the current cap structure (a single-rate cap and one or more ToU cap variants) but with an updated allowance?

Q9. Should the cap reflect demand profiles that are specific to default tariff customers? If so, what is your view on the distribution of outcomes across different groups of customers in the longer-term?

Q10. How should we set the demand profile for the cap allowances? Should the approach differ between commodity and non-commodity costs? In your response, please think about factors such as:

- how different groups of customers are settled (for example based on actual demand and LSS profiles)
- the parameters by which we set the cap
- the level at which we should benchmark demand (for example whether we should reflect an above average profile of peakiness)
- Please also note any differences in your answers when referring to the single-rate or ToU cap variant.

Q11. What different types of users should we set ToU cap variants for and how should we design these? In particular, what level of prescription should we adopt when setting ToU cap variants and should this differ between different ToU cap variants? For example, should we adopt a separate specific approach for EV customers to reflect stronger price signals?

Q13. What default tariff arrangements are required in the future as the market develops greater consumer-led flexibility and LCT adoption?

Q14. How often do you think we should update the demand profile used to set the allowances and what approach should we take to do so? For example should we carry out mechanistic updates similar to other allowances which are updated when the cap level is set?

4. Next steps

In this chapter, we set out our planned next steps following the publication of this call for input.

4.1 The impacts of MHHS are complex and wide-ranging, involving interdependencies across multiple market participants. We welcome the engagement from a range of stakeholders so far to provide data and insights to support this review. This call for input sets out our current thinking and views on how we progress options design. We encourage stakeholders, where appropriate, to provide detailed responses backed by analysis and evidence to the questions included and welcome any other relevant information and views on the issues we discuss. We are particularly interested in any future scenario analysis that stakeholders have to hand or are in the process of developing to support our own scenario analysis.

4.2 Our immediate next step is to continue progressing our analytical modelling of the MHHS impacts. The immediate impacts are clearer to analyse but longer-term impacts will require a greater reliance on scenario analysis given the different ways the market could develop. We intend to engage stakeholders to help design what scenarios will be most useful and pressing to consider.

4.3 Much of the discussion in this paper has focused on how we could set demand profiles for the wholesale allowances. As part of the review, we will need to consider the technical approach for incorporating any new views of demand into the cap methodology, primarily through the wholesale index and shaping allowance. We intend to engage stakeholders on the methodology through a potential combination of workshops and working papers over the summer as we work through our detailed options design.

Appendix1: Explanation of cap methodology

Wholesale costs

A1.1 Wholesale costs represent the single largest proportion of costs on consumer bills. In the cap, wholesale allowances cover a range of costs associated with procuring energy to meet final customer demand. They include:

- Wholesale index: Reflects the costs of purchasing initial hedging contracts which account for a significant majority of the total value of the wholesale allowances.
- Additional wholesale allowances (AWAs): These account for various ancillary costs associated with meeting final customer demand. These allowances are expressed as percentages and applied as uplifts to the wholesale index value. They include:
    - Shaping costs: costs of converting less granular forward contracts to more granular contracts closer to delivery.
    - Imbalance costs: costs to suppliers of market clearing when actual energy consumption deviates from forecast energy consumption.
    - Transaction costs: costs incurred by suppliers when they buy and sell energy to meet customers' demand.
    - Additional risk and uncertainty: cost of residual risks not explicitly accounted for within other wholesale allowances.
    - Electricity losses: cost of purchasing additional energy needed to cover expected electricity transmission and distribution losses.
- Backwardation: Accounts for the discrepancy between the 12-month forward looking nature of the wholesale index and the reality of suppliers' 3-month hedging behaviour under a quarterly price cap.
- Contracts for Difference (CfD) allowance: Accounts for costs associated with the Supplier Obligation Levy.
- Capacity Market (CM) allowance: Accounts for costs associated with the CM scheme.

Wholesale index

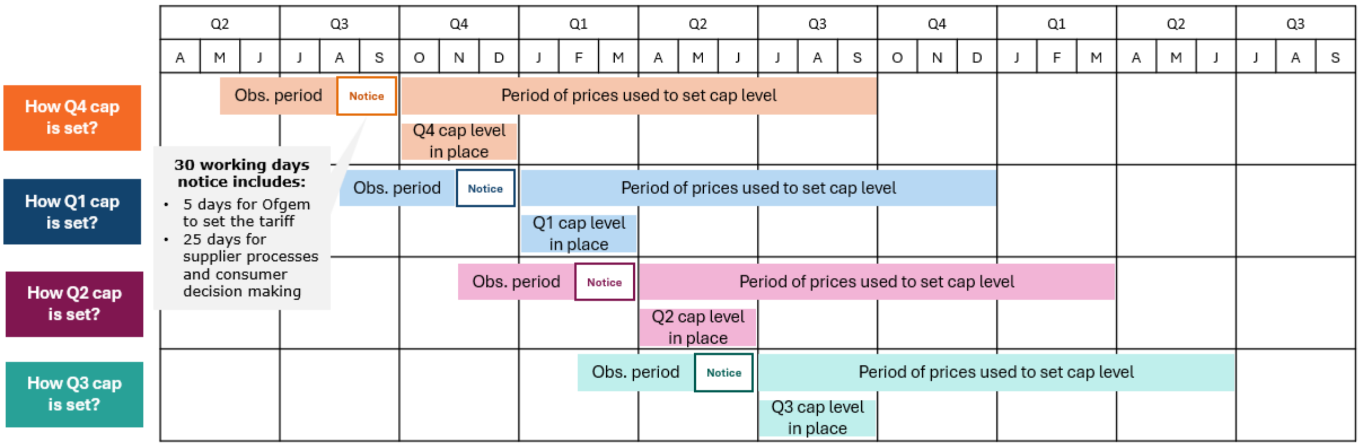
A1.2 The wholesale index aims to reflect the efficient costs of buying initial energy contracts (hedges) prior to the start of each quarterly price cap period. Hedging allows suppliers to lock in wholesale prices for future delivery, reducing the risk of differences between revenues and costs.

A1.3 The wholesale index assumes suppliers gradually buy initial energy contracts over a set period which we call an observation window. This helps to reduce the price volatility for the cap period, rather than relying on prices over a small number of days. To enable us to set the cap level and give suppliers time to notify customers about any future price changes, the wholesale index features a notice period between the observation window and the start of the cap period.

A1.4 Currently the wholesale methodology is operated using a 3-1.5-12 [3] index (as shown in Figure A1.1):

- a 3 month "observation window": The wholesale allowance is calculated as the average of daily wholesale prices for each trading day in the observation period (for forward contracts for the "forward view period").
- a 1.5 month "notice period": the lag between the end of the observation period and the start of the cap period is 30 working days.
- a 12 month "forward view period": the wholesale allowance observes contracts for delivery in the period from the start to the end of the cap period.
- a [3] month cap period, the frequency for updating the cap.

Figure A1.1: Quarterly update structure



A1.5 The electricity wholesale index is calculated on the assumption that energy suppliers purchase a combination of baseload and peak wholesale electricity contracts, where 70% of demand is baseload and 30% is peak. The quantity of contracts bought for each quarter is calculated using the quarterly demand share associated with profile classes 1 and 2.

Backwardation

A1.6 As the wholesale index is calculated over a 12-month period there is a risk that the wholesale index within the cap does not match the actual prices at which suppliers have hedged their energy. For example, when the forward prices in the later nine months of the cap are lower than in the first three (the actual cap period), the cap level is set below the cost to suppliers of purchasing that energy for customers (for that cap period). We call this backwardation. Contango is the opposite of backwardation, when the forward market prices for contracts closer to delivery are lower than prices further in the future. To reduce this risk for suppliers a backwardation allowance was introduced as part of our August 2022 decision on changes to the wholesale methodology, comprised of ex-ante modelled backwardation costs calculated quarterly with the cap.

A1.7 The backwardation allowance is calculated by determining the difference in wholesale costs of a 3-1.5-12 [3] index against a 3-1.5-3 [3] index, accounting for additional wholesale allowances, electricity losses (for electricity only), and quarterly demand share. These costs are recovered over a 6-month to 12-month period, helping to spread the cost for consumers.

Shaping

A1.8 Shaping refers to the process of buying and selling more granular energy contracts, for example monthly contracts, to adjust an existing position that was initially built using less granular contracts, including quarterly or seasonal contracts. This adjustment helps suppliers align their purchased energy more closely with forecasted demand patterns of customers. The difference in volume sold and bought and the difference in the price per unit of energy between the two contracts determine the cost of shaping.

A1.9 The cap shaping allowance is composed of three steps:

- Seasonal to monthly: The cost of buying additional or/and selling monthly contracts to convert seasonal demand to expected monthly demand patterns.
- Monthly to hourly: The cost of buying and selling additional day-ahead contracts to convert monthly demand to expected hourly demand patterns.
- Day-ahead: The cost of buying and selling day-ahead contracts to account for the difference between seasonally normal demand and actual out-turn demand.

A1.10 The current shaping allowances were set in 2018. They are calculated by multiplying the demand delta for a sub-period (ie the difference between seasonal and monthly demand shapes) by the price for that sub-period (ie average monthly contract prices), giving a £ per customer figure. This is then converted to a £ per unit of energy value by dividing by benchmark consumption and then expressed as a percentage of a reference price (the wholesale index at the time of calculation) and applied as an uplift to the wholesale index.

Table A1.1: Current electricity shaping allowances

Allowance	**Value (%)**
Seasonal to monthly	0.23%
Monthly to hourly	4.16%
Day-ahead	0.29%

A1.11 The use of seasonal contracts in the calculation of the seasonal to monthly shaping allowance no longer aligns with the wholesale index methodology, which assumes only quarterly contracts are purchased. While suppliers may still purchase and shape seasonal contracts, for commercial reasons or when liquidity for quarterly contracts is limited, doing so is not in line with the assumed behaviour of the notional supplier.

A1.12 As customers will be settled against their half-hourly usage, MHHS is expected to reveal differences in the shaping costs associated with the distinct demand patterns of individual customers. However, through previous engagement, suppliers have explained that they shape for entire cohorts of customers in their portfolio (for example all their default tariff customers), rather than individual customers. As a result, shaping costs in aggregate would only be expected to change if there is a difference in the demand shape of suppliers' average customer pre- and post-MHHS, or a change in wholesale prices.

Imbalance

A1.13 When suppliers deliver energy, they must match their supply to the specific shape of customers' demand on a particular day. If customers' demand is different than forecasted, the energy contracted by the supplier does not match the actual volumes of energy used by its customers. In aggregate, across the market this can lead to an imbalance in the system to which the system operator must respond.

A1.14 Broadly, there are two aspects to the settlement process: (1) the physical system balancing where generators are instructed to increase or decrease output to balance the system; and (2) market clearing, where the wholesale contracts suppliers have purchased to supply energy to their customers are matched against the customers' demand and differences are either charged or paid out at the imbalance price.

A1.15 While demand forecasting is a core role for suppliers, it is inevitable that there will be some differences between forecast and actual demand. Therefore, an imbalance allowance is given to suppliers to recover the costs incurred of being exposed to the imbalance price as part of the market clearing process.

A1.16 The current allowances were set in 2018 using a sample of actual supplier imbalance positions. We multiplied the average volumetric imbalance of suppliers in the sample by the average absolute price difference between system prices and day-ahead prices. We conservatively assume that the change in price is always in the wrong direction, increasing the allowance. The resulting imbalance costs are then compared to a reference wholesale price (the wholesale index at the time of calculation) to give allowances as a percentage of wholesale costs. The current electricity imbalance allowance is set at 1.31%.

A1.17 As the number of customers settled on actual half-hourly data rather than profile class data increases, it may become more challenging for suppliers to accurately forecast the demand of their customer base. This transition could increase the level of imbalances in the short term. Furthermore, if one supplier has a higher proportion of customers with demand that is hard to predict, it may also struggle to accurately forecast demand. However, this initial imbalance exposure is expected to reduce over time as suppliers become accustomed to forecasting actual half-hourly demand and adopt flexibility strategies that reduce their imbalance positions.

Non-commodity costs

A1.18 There are several allowances unrelated to wholesale costs ("non-commodity charges") that are impacted in part or in full by consumption patterns, notably Transmission Network Use of System (TNUoS), Distribution Use of System (DUoS), and Capacity Market (CM) charges. As with the commodity related charges which make up the wholesale allowances, we understand that these non-commodity charges have used the relevant assumed profile classes in the absence of the actual demand data to estimate consumption.

- TNUoS: these charges recover the costs of installing and maintaining the transmission network across GB and offshore. TNUoS charges are calculated based both on a fixed element and an element which is based on assumed annual consumption during the peak period of 4-7 pm.
- DUoS: these charges recover the cost of operation, maintenance and investment in locally electricity distribution networks. DUoS charges are calculated via a fixed element, as well as Red, Amber, Green (RAG) unit

charges split by different time bands with the most expensive time band being during peak hours throughout the day.

- CM: these charges support investment in future capacity and maintenance of existing capacity to ensure sufficient electricity generation during peak periods. CM charges are calculated using gross demand during winter peak periods (weekdays, 4-7pm, November – February); there is no fixed element in this charge.

A1.19 Non-commodity costs with a half-hourly charging basis totalled approximately £190 per typical electricity customer under the January to March 2026 price cap (note we've maintained use of this cap period for the call for input as it aligns with the analysis we have carried out – we're aware the value of CM increased in the April 2026 cap period). Around half of these costs are recovered through the volumetric element of the bill, with the remainder recovered via the standing charge. We understand that MHHS could expose suppliers to changes in costs on the volumetric portion of the bill, if suppliers' actual customer demand differs from the current profile classes.

A1.20 Of the half-hourly-linked (volumetric) portion, approximately 74% is driven by peak-time consumption. This reflects the structure of network charges, under which only a subset of DUoS charges are levied on off-peak usage, while the majority are concentrated in peak periods.

A1.21 DUoS charges are the largest contributor to half-hourly-linked non-commodity costs and include both peak and off-peak elements. Around 64% of DUoS variable charges are incurred during peak periods. By contrast, CM and TNUoS costs are entirely driven by peak demand in their volumetric components, although TNUoS has a much smaller volumetric share overall. CM costs are recovered exclusively through the volumetric component of customers' bills, making them fully sensitive to changes in peak-time consumption.

A1.22 DUoS charges vary significantly by region, reflecting the fact that each distribution network company sets its own localised tariff structure. This results in substantial geographic variation in the level and composition of DUoS charges faced by customers. While there is some regional variation in TNUoS costs, this is more limited, as the majority of TNUoS charges are recovered through fixed charges rather than volumetric rates.

A1.23 We expect that customers who consume more electricity at peak times will incur more of these charges on behalf of their suppliers. The exposure to actual half-hourly demand varies between these three charges as some are partially recovered on a fixed-cost basis. As the tables below show, DUoS charges are most impacted by peak demand, followed by CM. TNUoS has a much smaller element of peak cost recovery given that the majority of the charge is recovered through the fixed-cost element.

Table A1.2: Non-commodity costs by Nil/volumetric

	Nil	TDCV*	Volumetric portion (TDCV-Nil)	% of volumetric portion
CM	0.00	24.05	24.05	100%
TNUoS	49.29	51.25	1.96	4%
DUoS	45.91	115.27	69.36	60%
Total	95.20	190.58	95.37	**50%**

Note: Jan-Mar26 cap, single rate electricity customer, benchmark consumption (2,700 kWh electricity). Simple average across regions.

**TDCV (Typical Domestic Consumption Values) are estimates made by Ofgem of the annual electricity and gas consumption for a "typical" household, expressed in kWh. They are used in the price cap to convert capped unit rates and standing charges into a notional total annual bill level (the headline cap). The figures in this column relate to non-commodity cost charges for a single rate default tariff electricity customer based on typical consumption as defined by TDCV. The figures under the previous column relate to the non-commodity cost charges applied to the standing charge only (ie based on nil consumption)*

Table A1.3: Non-commodity costs charged at peak and off-peak hours

	Charged at peak hours*	Charged at off-peak hours	%
CM	24.05	0.00	100%
TNUoS	1.96	0.00	100%
DUoS	44.33	25.03	64%
Total	70.34	25.03	**74%**

Note: Jan-Mar26 cap, single rate electricity customer, benchmark consumption (3,1000 kWh electricity). Simple average across regions.

**The definition of 'peak hours' varies by region but typically refers to between 16:00-19:00.*

Setting a multi-register cap

A1.24 While the price cap sets a single capped unit rate for single rate default tariffs, ToU default and evergreen tariffs which have multiple rates are still compatible with the cap through the "multi-register" cap. The multi-register cap does not involve explicitly setting caps on volumetric charges by time of day unlike the single rate cap. Instead, suppliers can independently price ToU tariffs provided that customers do not pay more overall than an overall price cap unit rate, based on how much electricity they are assumed to consume for each price band period.

A1.25 Compliance is assessed by ensuring that the demand weighted average volumetric charge of any given tariff does not exceed the level set by the electricity multi-register price cap. For Economy 7 tariffs, we weight the day and night rate using an assumed customer consumption ratio of 58% for the day and 42% for nighttime. For other ToU tariffs with a greater number of rates, we assess compliance using historic consumption data, or reasonable estimates of consumption splits, to calculate a weighted average rate which can be compared to the price cap unit rate.

A1.26 Suppliers can still set different rates for individual time periods, provided that the weighted average is compliant. For example, one supplier might set a higher day rate than another supplier and then meet the weighted average requirement by setting a lower night rate.

A1.27 The multi-register cap already doesn't currently accurately reflect the demand profile of Economy 7 and Economy 10 customers and their wholesale cost to serve. Currently the assumed 70/30 baseload/peakload consumption ratio in the cap is the same for single-rate and multi-register metering arrangements. This is despite the fact that the demand profile of a customer with a multi-register meter (such as an Economy 7 meter) is likely to be substantially different from a customer with a single-rate meter, likely reflecting consumption of a lower proportion of peakload electricity.

A1.28 Similarly, the shaping allowance within the cap assumes the same percentage uplift for both single-rate and multi-register metering arrangements, despite the differences in within-day demand. Therefore, separate different baseload/peakload ratio assumptions may be appropriate which we will consider as part of the wholesale allowance review.

Send us your feedback

We believe that consultation is at the heart of good policy development. We are keen to receive your comments about this Call for input. We would also like to get your answers to these questions:

- Do you have any comments about the quality of this document?
- Do you have any comments about its tone and content?
- Was it easy to read and understand? Or could it have been better written?
- Are its conclusions balanced?
- Did it make reasoned recommendations?
- Do you have any further comments?

Please send your feedback to stakeholders@ofgem.gov.uk.