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Impact Assessment

Electricity retail market-wide half-hourly settlement: draft IA

Division:	Consumers & Markets	**Type of measure:**	Codes/Retail Competition measures
Team:	Settlement Reform	**Type of IA:**	Section 5A of the Utilities Act 2000
Associated documents:	Consultation document	**Contact for enquiries:**	halfhourlysettlement@ofgem.gov.uk
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The energy system is undergoing fundamental change, driven by the need to decarbonise energy supplies and by technological innovation. At the same time, electricity demand is expected to increase. Managing the transition in a flexible way that minimises costs requires changes to market and regulatory arrangements.

Market-wide half-hourly settlement **(MHHS)** is a vital enabler of flexibility. It builds on changes to require half-hourly settlement **(HHS)** for medium to large non-domestic consumers and to facilitate elective HHS for domestic and smaller non-domestic consumers. MHHS will send accurate signals to suppliers about the cost of serving their customers throughout each day. This will place incentives on suppliers to offer new tariffs and products that encourage more flexible use of energy and help consumers to lower their bills. Making best use of existing infrastructure should reduce the need for future generation and network investment. This will help decarbonise the sector cost-effectively, which will benefit all consumers and wider society.

This draft impact assessment **(IA)** evaluates options for introducing MHHS as compared with keeping the elective regime. Alongside it, we have published a consultation document seeking views on specific aspects of MHHS and a separate paper on the potential consumer impact of MHHS. The deadline for responding to this consultation is **14 September 2020**.

The analysis in these documents was carried out before the coronavirus national emergency. We are publishing them now for transparency. We recognise that the transition timescales set out in our analysis are likely to be impacted by the current COVID-19 situation, and our consultation asks stakeholders for their views on how this impact will affect the timescales from their perspective.

We previously published this draft IA on 30 April 2020. The table below summarises the revisions we have now made to that document.

Page	Revisions
Cover	Inserted new publication date
Cover	Inserted consultation deadline date
1	Removed reference to the lack of a consultation deadline date
3	Inserted hyperlinks from the list of contents to each chapter
7	Inserted new target for publishing the Full Business Case
89	Inserted new target for publishing the Full Business Case

Contents

Summary: rationale for intervention and options

What is the problem?

Electricity settlement takes place every half hour. Most domestic and small non-domestic electricity customers have not had meters that can record half-hourly **(HH)** consumption, so their consumption has been estimated for each half hour. This is done by assigning these customers to one of four profile classes that are used to estimate a profile of consumption over time and to allocate the total energy used to each half-hour period.

This arrangement does not expose suppliers to variations in the consumption patterns of their own customers or to the true cost of supplying their customers throughout the day. So far, therefore, suppliers and other retailers have not been fully incentivised to innovate by offering smart tariffs and/or other products that help customers to shift consumption from peak periods. Yet retailers have a crucial role in fostering behaviour change in homes and businesses by developing and marketing compelling and trustworthy products and services that make it easy for consumers to use energy more efficiently.

Without substantial load shifting over time, there will need to be significant and costly investment in generation and network assets to meet rising peak demand. This would increase the costs of integrating low carbon, intermittent generation and new sources of demand, such as electric vehicles. Based on experience to date and new evidence about stakeholders' future plans under the elective half-hourly settlement (**HHS**) arrangements, we do not expect the existing regime to deliver the tariff and product innovation that will be required to encourage customer load shifting on a scale or at a pace that would ease pressure significantly on the electricity system.

Current settlement arrangements are also inefficient. The reconciliation process is lengthy and market participants have to hold enough credit cover to meet their potential liabilities. Costs associated with these inefficiencies are likely to be passed onto customers.

Why is Ofgem intervention necessary?

The evidence suggests that the elective HHS arrangements will not deliver load shifting on a scale that will produce system-wide benefits. Consequently, there is a need to mandate HHS across the smaller non-domestic and the domestic electricity market. Introducing market-wide half-hourly settlement (**MHHS**) requires significant regulatory change. Past experience of major reform programmes suggests that that change will need to be sponsored by Ofgem to ensure that it can be delivered efficiently.

What are the policy objectives and intended effects, including the effect on Ofgem's Strategic Outcomes?

The strategic objective is to minimise the overall cost to current and future consumers of moving to a net zero carbon electricity system while maintaining security of supply and system efficiency. Within that, the aim of the settlement reform project is to develop settlement arrangements that incentivise all energy suppliers and other retailers to encourage behaviour that contributes to a more cost-effective electricity system. As set out in our Decarbonisation Action Plan, we will ensure that those who cannot provide flexibility are not unduly disadvantaged. These objectives align with Ofgem's regulatory stances[1], our principal objective[2] to protect the interests of existing and future consumers, our strategic narrative[3] until 2023 and our Decarbonisation Action Plan.[4]

What are the policy options that have been considered, including any alternatives to regulation?

Retain the existing elective HHS arrangements (the counterfactual, option 1).

Introduce MHHS based on the Design Working Group's (**DWG's**) recommended Target Operating Model (**TOM**) for all Meter Point Administration Numbers (**MPANs**) with a transition period of approximately 4 years up to the end of 2024 (option 2, preferred by Ofgem).

Introduce MHHS based on the DWG's recommended TOM for import-related MPANs only with a transition period of approximately 5 years up to the end of 2025 (option 3).

Preferred option justification (option 2)

Based on the evidence we have seen, we think that retaining the elective arrangements (option 1) will not deliver sufficient levels of load shifting to meet our objectives for the project. Option 3 unnecessarily delays the benefits of MHHS for import-related MPANs and precludes the benefits of settling all export-related MPANs on a HH basis.

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[1] Ofgem's regulatory stances are set out on the Ofgem website.
[2] See 'Powers and duties of GEMA' on the Ofgem website.
[3] Ofgem's strategic narrative for 2019-23 can be found on the Ofgem website.
[4] Ofgem's decarbonisation action plan can be found on the Ofgem website.

We have also considered whether the transition to MHHS could be completed on a shorter timeframe, for example within a 3-year period. After receiving feedback from a variety of stakeholders, we concluded this would not be practicable. One key consideration is that industry resources will be fully committed to delivering faster switching by the end of 2021.

Balancing the desire to deliver the benefits of MHHS as soon as possible, with the need to ensure that the new arrangements (including central settlement systems) are robust, we believed - at the time of our analysis - that a transitional period of approximately 4 years would be appropriate. This timeframe still represents a challenge, but we consider it likely to be realistic and achievable with appropriate programme governance. However, the analysis that underpins the IA and consultation document was carried out before the onset of the coronavirus national emergency in Great Britain. We are publishing now in the interests of transparency. We will take account of the impacts of the developing public health situation on the project as we proceed.

Option 2 was Ofgem's preferred option at the time of our analysis. We believe it would place powerful new incentives on industry parties to offer a range of innovative products and services to consumers and thereby encourage substantial load shifting. This would in turn deliver significant consumer and societal benefits.

Consultation document

Alongside this draft IA, we have today published a consultation document seeking views on a range of specific issues relating to the introduction of MHHS. We are particularly keen for feedback on:

- the TOM, including data aggregation arrangements
- proposed changes to the settlement timetable
- settlement arrangements for export-related MPANs
- the length of the transition to the new settlement arrangements
- data access and privacy issues and associated consumer messaging approaches
- programme governance arrangements, and
- the impact that stakeholders think the coronavirus national emergency will have on the project timescales.

The consultation document contains a glossary of terms, which includes those used in this Impact Assessment (**IA**). We have also published a separate paper on the potential consumer impacts of MHHS.[5]

The Full Business Case (**FBC**), including the Final IA, will set out the impact of our decisions on these issues. We had planned to publish the FBC in autumn 2020 but now expect to do so in spring 2021.

Preferred option - Monetised Impacts (£ millions)

Business Impact Target Qualifying Provision	N/A
Business Impact Target (EANDCB)	N/A

We expect this policy measure to enhance competition between suppliers and other retailers in the provision of innovative products and services that lead to consumer behaviour change.

In its 2016 Energy Market Review findings, the Competition and Markets Authority (**CMA**) found that "the absence of a firm plan for moving to half-hourly settlement for domestic electricity customers is a feature of the market for domestic and small and medium-sized enterprises (**SMEs**) retail electricity supply in Great Britain that gives rise to an adverse effect on competition through the distortion of suppliers' incentives to encourage their customers to change their consumption profile, which overall reduces the efficiency, and therefore the competitiveness, of domestic and microbusiness retail electricity supply."[6]

Option 2 effectively remedies this adverse effect on competition. Therefore, in line with Government guidance, we classify it as a non-qualifying regulatory provision. We rely mainly on administrative exclusion D ("Deliver or replicate better competition-based outcomes in markets characterised by market power: Pro-competition document").[7]

[5] The consultation document and consumer impacts paper are available here.
[6] Competition and Markets Authority, Energy Market Investigation 2016, paragraph 187, page 44.
[7] As stipulated by the Department of Business, Industry and Energy Strategy's Better Regulation Framework Interim guidance 2020, page 33.

Expected range of net benefit to GB consumers[8]	**£1,607m-£4,557m**
Expected range of wider benefits/costs for society[9]	**£707m-£3,107m**
Net Benefit is presented in Net Present Value terms (**NPV**) relative to the counterfactual. NPV is calculated using 2018 as the base year. Economic costs and benefits are in 2018 financial year prices covering the period from 2021 to 2045. Figures in this table are rounded to the nearest £1m. Cost/benefit figures in this draft IA are in 2019 prices unless stated otherwise. The quantified benefits in chapter 4 are rounded to the nearest £50m but the quantified costs in chapter 3 and the quantified net consumer benefits in chapter 6 are rounded to the nearest £0.1m. Therefore, some totals may not correspond with the sum of the separate figures.	

[8] The net benefit to GB consumers refers to the modelled benefits to consumers and the monetised direct costs. It is calculated by subtracting the monetised direct costs from the modelled consumer benefits (consumer surplus).

[9] The wider net benefits/costs for society refers to the net benefit to GB consumers plus other quantified impacts for society (ie, the impact on producers (generators), environmental tax revenue, unpriced carbon and interconnectors). This is calculated by subtracting the monetised direct costs from the modelled net welfare benefits. By way of comparison, in our Outline Business Case (**OBC**) published in August 2018, the headline benefits figures referred to the modelled net welfare benefits and did not capture the monetised direct costs, which were quoted separately.

Preferred option - Hard to Monetise Impacts

The monetised figures do not represent the full benefits to consumers. We expect that option 2 will achieve further benefits from greater competition and innovation. Better quality and more frequent settlement data for both imported and exported volumes, combined with greater administrative efficiency, should encourage non-traditional players with disruptive business models to enter the market and compete with existing suppliers. This new entry, together with new price signals, should stimulate an innovative response from those already in the market. A faster settlement timetable means suppliers would need less collateral to cover their potential settlement liabilities. This should reduce barriers to new entry.

The resulting innovation in energy services and products should improve outcomes for consumers. For example, MHHS is expected to accelerate the growth of new energy 'tariff-only' propositions, third party managed energy services involving smart controls, bundled 'asset and tariff' offerings managed by the consumer or on their behalf; and offer consumers new ways to offer flexibility to the energy system such as peer-to-peer (**P2P**) trading and grid balancing services.

Making non-aggregated data available to central settlement systems will make aggregation for settlement more flexible and future proof. Making non-aggregated data available to industry (under the right data protection rules) should also stimulate innovation in value-added services, as well as other new business models (for instance, flexibility offerings such as demand-side response (**DSR**) and P2P trading, as well as opening up the market to allow parties to provide better tariff comparisons and potential use by third party intermediaries (**TPIs**)). Finally, making the data available to academics and policy-makers, aggregated and anonymised in accordance with data protection rules, should improve understanding and public policy-making in the future. We have not monetised these benefits as it is hard to value innovations, and the barriers to them, that are presently unknown.

We also cannot monetise the cost to consumers of taking up new product and service choices such as smart appliances. If take up is lower than we expect, this would reduce the value of the benefits that are realised from MHHS. We have, however, sought to monetise the costs to suppliers of offering HHS-enabled products such as time of use (**ToU**) tariffs and presented this as a cost sensitivity.

Key assumptions/sensitivities/risks

We have considered several potential risks relating to MHHS. Broadly, these cover

- **transitional risks** while the industry prepares for and implements MHHS, including interdependencies with other programmes that could affect the quality and speed of delivery

- **ongoing post-implementation risks**, such as
  - consumer concern about sharing HH consumption data
  - low uptake of smart tariffs (such as ToU tariffs) and
  - conversely, the potential distributional impacts that may arise if the take up of such tariffs is widespread.

The scale of benefits that can be achieved from MHHS depends on successful rollout of smart meters, the levels of data available for settlement, and the market and consumer response. We have adopted mechanisms to test whether option 2 will deliver net benefits to consumers under a range of plausible assumptions and scenarios.

There is, in particular, significant uncertainty about the level of load shifting that is feasible. To reflect this uncertainty, we have used a relatively wide assumption range. We welcome views on this, and have asked a question about it in the consultation accompanying this draft IA.

Will the policy be reviewed?	**If applicable, set review date:**
Existing industry governance processes will remain in place to provide ongoing monitoring of the quality of supplier performance under MHHS. Ofgem envisages routine monitoring of load shifting trends and opt out rates. In light of this information, we will review the data access arrangements to ensure that they remain proportionate.	We are likely to review the data access arrangements no later than 3 years after the end of the transition period. However, we will only undertake the review when we feel we have sufficient evidence to do so.

Is this proposal in scope of the Public Sector Equality Duty?	**Yes**

Summary table for all options

Summary of options	**Main effects on consumer outcomes**	**Benefits**	**Costs**	**Key considerations** (Risks, assumptions, distributional impacts etc.)
Option 1 – Existing 'elective' HHS (the counter factual)	Status quo. Slow progress towards greater flexibility and decarbonisation	Status quo	Status quo	Likely that only less peaky consumers will be settled HH. Likelihood of only limited increases in competition and of inefficient network and generation spending
Option 2 - MHHS for import and export with a transition period of approximately 4 years (Ofgem's preferred option)	New products and services, with improved quality and convenience for consumers. Downward price pressure as system cost savings passed on to consumers. Higher load shifting. Faster decarbonisation	Better demand forecasting. Lower balancing costs. Reduced collateral needs. Maximises new entry and innovation	We expect that firms will pass programme and delivery costs through to consumers	More accurate consumption data spurs innovation
Option 3 - MHHS for import only with a transition period of approximately 5 years	Faster decarbonisation than under elective HHS but slower than option 2 due to delayed import benefits and a lack of incentive to innovate and load shift for export	Greater new entry and innovation than option 1 but significantly less than for option 2. Better data for forecasting and network planning than option 1 but not as much as in option 2	Export allocation inefficiencies are passed through	Growth of exporting technologies over time is not well integrated into system

In preparing this IA we have had regard to better regulation principles which, amongst other things, state that an IA should be developed transparently, and should concisely and consistently summarise the quantitative and qualitative impacts of the options we have considered.

Associated documents

- Ahmad Faruqui and Sanem Sergici, Arcturus: International Evidence on Dynamic Pricing (July 2013)
- Baringa, Electricity System Analysis – future system benefits from selected DSR scenarios (August 2012)
- Carbon Trust and Imperial College London, An analysis of electricity system flexibility for Great Britain (November 2016)
- Centre for Sustainable Energy, Beyond average consumption - Development of a framework for assessing impact of policy proposals on different consumer groups (June 2014)
- CEPA for Ofgem, Distributional Impacts of Time of Use Tariffs (July 2017)
- Competition and Markets Authority, Energy market investigation final report (June 2016)
- Competition and Markets Authority, Energy market investigation Final report (June 2016)
- Department for Business, Energy & Industrial Strategy, Better Regulation Framework Guidance (March 2020)
- Department for Business, Energy and Industrial Strategy Updated short-term traded carbon values used for UK policy appraisal 2017 (January 2018)
- Department for Business, Energy and Industrial Strategy, Hinkley Point C: Value for Money Assessment (June 2017)
- Department for Business, Energy and Industrial Strategy, Smart meter roll-out: cost-benefit analysis 2019 (September 2019)
- Department for Business, Energy and Industrial Strategy, Updated energy and emissions projections: 2018 (April 2019)
- Department for Business, Energy and Industrial Strategy, UPDATED SHORT-TERM TRADED CARBON VALUES: Used for UK Public Policy Appraisal (January 2018)
- Department for Energy and Climate Change, DECC Dynamic Dispatch Model (May 2012)
- Department for Transport, National Travel Survey (July 2019)
- Department for Transport, The Road to Zero: Next steps towards cleaner road transport and delivering our Industrial Strategy (July 2018)
- Dr Timur Yunusov and Dr Jacopo Torriti - University of Reading, Distributional effects of Time of Use tariffs based on smart meter electricity demand and time use activities. Energy Policy (submitted)
- EA Technology, Assessing the Impact of Low Carbon Technologies on Great Britain's Power Distribution Networks (July 2012)

- ELEXON, Change of Measurement Class and Change of Profile Class (June 2019)
- Energy Systems Catapult, Smart Systems and Heat: Phase 2 – Summary of Key Insights (March 2019)
- Frontier Economics with support from LCP and Sustainability First, Future potential for DSR in GB (October 2015)
- HM Treasury, Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal (April 2019)
- HM Treasury, The Green Book: Central Government Guidance on Appraisal and Evaluation (March 2018)
- Octopus, Agile Octopus: A consumer-led shift to a low carbon future (September 2018)
- Ofgem, Consumer Survey 2019: Tracking data and insights into future energy solutions (February 2020)
- Ofgem, Consumer Vulnerability Strategy 2025 (October 2019)
- Ofgem, Decision on the Initial Project Assessment of the FAB Link, IFA2 and Viking Link interconnectors (July 2015)
- Ofgem, Decision on the Initial Project Assessment of the GridLink, NeuConnect and NorthConnect interconnectors (January 2018)
- Ofgem, Market-wide Settlement Reform: Outline Business Case (August 2018)
- Ofgem, Ofgem decarbonisation programme action plan (February 2020)
- Ofgem, Ofgem's regulatory stances (December 2016)
- Ofgem, Our powers and duties (July 2013)
- Ofgem, Our strategic narrative for 2019-23 (July 2019)
- Ofgem, Our strategy for regulating the future energy system (August 2017)
- Ofgem, State of the energy market 2019 Report (November 2019)
- Smart Energy GB, Consumer appetite to buy energy through a lifestyle service company (March 2018)
- The Brattle Group and UCL for Citizens Advice, The Value of TOU Tariffs in Great Britain: Insights for Decision-makers (July 2017)
- UK Power Networks, Low Carbon London (March 2015)
- US Department of Energy, Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies (November 2016).

1. Problem under consideration

Section summary

In this section we describe the problems with the current settlement arrangements, set out why we need to intervene, and state our project objectives in doing so.

1.1. Energy suppliers purchase most of their electricity in advance based on their forecasted estimates of what they expect their customers to use in half-hour (**HH**) periods through the day. The difference in each HH period between the volumes of electricity purchased by suppliers to cover their needs, and the volumes their customers are assumed to have used, are identified, reconciled and paid for through the settlement system.

1.2. Consumers have traditionally been settled against an estimated profile of their consumption in each HH period. There are currently four estimated profiles - called Profile Classes (**PC**).[10] These apply to domestic and smaller non-domestic consumers. Estimated, non-half-hourly (**NHH**) arrangements have operated for domestic and small non-domestic consumers since the GB electricity supply market was opened to competition in 1998.

1.3. Arrangements for cost-effectively settling domestic and small non-domestic consumers using actual HH consumption data (rather than estimates) were put in place in 2017 on an elective (voluntary) basis. Half-hourly settlement (**HHS**) on a mandatory basis has been in place since 1 April 2017 for medium to large non-domestic consumers. The NHH arrangements that preceded this had operated since 1 April 1994.

1.4. Smart meters are being rolled out to domestic and small non-domestic consumers. This will enable the recording of actual consumption in each HH period. However, until smart meters and market-wide half-hourly settlement (**MHHS**) are in place,

[10] For more information on profile classes visit the ELEXON website.

suppliers will – unless they have elected to adopt HHS - continue to forecast the energy requirements needed to meet their customers' consumption based on estimates and standard NHH load profiles rather than their customers' actual usage data.

Rationale for intervention

1.5. This reliance on estimates means suppliers are not exposed to any variations in consumption patterns or to the true cost of supplying their customers throughout the day. Suppliers and other retailers consequently have little incentive to innovate by offering smart tariffs and/or other products (such as batteries) that enable more flexible use of energy leading to a reduction in generation and network demand at expensive peak periods.

1.6. Suppliers may opt to introduce HHS and new products through elective HHS. However, without exposing suppliers to the cost of supply of all of their customers in each HH period, we are unlikely to see these products develop to an extent that will bring significant system-level benefits or at a speed that will help the UK achieve its Net Zero commitments. We expressed this view in the Outline Business Case (**OBC**) and evidence from suppliers in our recent Request for Information (**RfI**) supports it. As at January 2020, less than 1% of metering points were settled under the elective arrangements (registered as HH sub-100kW domestic).

1.7. Increases in intermittent generation, rising electricity demand and the development of new technologies will further increase the need for flexibility to ensure we make the best use of the energy system and keep consumer bills as low as possible. Part of this involves consumption patterns evolving to ease pressures on the grid, utilising the potential new products and innovation that we expect to be introduced as a result of MHHS. Without this, there would likely need to be significant and costly investment in network and generation assets to manage peak demand. The costs of integrating low carbon, intermittent generation and new sources of demand like electric vehicles (**EVs**), would be higher.

1.8. MHHS is a key enabler for increasing flexibility in the system, and for many parts of the BEIS/Ofgem smart system and flexibility plan. According to a study by the

Carbon Trust and Imperial College London, moving to a more flexible electricity system could save the UK £17-40 billion by 2050.[11]

1.9. The current settlement arrangements do not capitalise on the potential for smart meters to bring efficiency gains. Without smart meters, market participants forecast their purchasing requirements based on profile data rather than HH consumption data. Market participants are also uncertain about their liabilities to each other because of the length of time taken to reconcile settlement volumes fully (up to 28 months). This can mean market participants are uncertain of their financial position for a long time, and must hold collateral for about one month. These inefficient costs may be passed to consumers. Reducing settlement collateral requirements should reduce entry barriers.[12]

1.10. The smart meter rollout presents an opportunity to introduce HHS on a market-wide basis. This can then facilitate several benefits to consumers:

- greater innovation and competition in the energy market
- the right environment for system efficiency gains through demand side response
- improved supplier forecasting of customer demand should lower suppliers' wholesale costs, which can be passed on to consumers, and
- making the settlement process itself more efficient, thus reducing costs.

Project objectives

1.11. The strategic objective is to deliver the Government's and Ofgem's objectives in a cost-effective manner, minimising the overall cost to current and future consumers

[11] See 'An analysis of electricity system flexibility for Great Britain' for more detail.
[12] When a supplier fails, certain costs can be mutualised across other suppliers. While this helps to ensure that the failed supplier's customer credit balances are protected, and that the integrity of government schemes is maintained, we want to reduce the wider impact that supplier failure has on other suppliers and consumers. Part of this means taking action to ensure the current cost mutualisation arrangements do not encourage inefficient entry or expansion of poorly-prepared suppliers. We are consulting on ways we might achieve this as part of our Supplier Licensing Review. Our aim is to improve supplier standards of financial resilience without presenting any undue barriers to entry, innovation or expansion. The reduction in settlement collateral requirements would reduce any such barriers irrespective of the cost mutualisation proposal we take forward.

of moving to a net zero carbon electricity system while maintaining security of supply and system efficiency. We will do this by minimising the need for infrastructure investment and facilitating more efficient use of generation and network assets.

1.12. Within that, the aim of the settlement reform project is to develop settlement arrangements that incentivise all energy suppliers and other retailers to encourage behaviour that contributes to a more cost-effective electricity system. We will do this by:

- linking future retailers' costs to their customers' actual consumption throughout the day

- encouraging new and disruptive business models through settlement arrangements that facilitate competition in new areas, leading to product and service innovation – for example, storage and automation and/or pricing - that encourages more flexible use of energy in ways that reduces consumers' bills and their carbon footprint.

1.13. Ofgem has a role to play in ensuring that the conditions are in place for innovative products and services to emerge and for consumers to be suitably protected when using them. As set out in our Decarbonisation Action Plan,[13] we will therefore also ensure that those who cannot provide flexibility are not unduly disadvantaged.

1.14. These objectives align with:

- Ofgem's principal objective to protect the interests of existing and future consumers

- our published regulatory stances

- our strategic narrative until 2023, and

- our Decarbonisation Action Plan.

[13] See Ofgem, Ofgem decarbonisation programme action plan (February 2020).

2. Options under consideration

Section summary

In this section we briefly describe the options that have been considered. These are

- retaining elective half-hourly settlement (**HHS**) arrangements (option 1)
- introducing market-wide half-hourly settlement (**MHHS**) for import and export Meter Point Administration Numbers (**MPANs**) with a transition period of approximately 4 years (option 2, Ofgem's preferred option)
- introducing MHHS for import MPANs only with a transition period of approximately 5 years (option 3).

Options

2.1. We have considered the impact of retaining the elective HHS arrangements and whether doing so would be compatible with achieving the project objectives set out above. This is option 1 (the counterfactual).

2.2. We have considered two alternative options for introducing MHHS. These are:

- Introduce MHHS based on the Design Working Group's (**DWG's**) recommended Target Operating Model (**TOM**) for all MPANs with a transition period of approximately 4 years ending at end-2024[14] (option 2, preferred by Ofgem)
- Introduce MHHS based on the DWG's recommended TOM for import MPANs only with a transition period of approximately 5 years ending at end-2025 (option 3).

[14] Note that we are keeping all timescales for the project under review as a result of the COVID-19 pandemic, and our consultation asks stakeholders for their views on these impacts.

Features common to options 2 and 3

2.3. Under options 2 and 3 there would be a two-phase period involving implementation (including systems design, development and testing), then a 1-year period for migration. In option 2, the implementation phase would last for 3 years – in our analysis, beginning in January 2021 and running to the end of 2023. The migration phase would follow and last 1 year – in our analysis, running to the end of 2024. In option 3, the implementation phase would last for 4 years – in our analysis, beginning in January 2021 and running to the end of 2024. The migration phase would follow and last 1 year – in our analysis, running to the end of 2025.[15] (As noted above, we will take account of the impacts of the developing public health situation on the project as we move forward.)

2.4. There would be a faster, more efficient settlement timetable. Non-aggregated HH consumption data would be made available to central settlement systems.[16] Suppliers would have daily access, via the Data Communications Company (**DCC**), to a day's worth of data from every meter.

*Consumer consent to sharing half-hourly (**HH**) consumption data*

2.5. At present, in order for suppliers (or parties acting on their behalf) to collect consumers' HH data for any purpose, including settlement and forecasting, domestic consumers must have provided opt-in consent. Where a domestic consumer does not opt in to HH collection, the supplier may collect data at daily resolution by default. The consumer also has the right to opt out to monthly resolution of data collection, except for certain regulated purposes such as investigating suspected theft/fraud, and in order to provide an accurate bill, in which cases daily resolution data may be collected.

2.6. Under MHHS the party responsible for settlement will have a legal requirement to collect HH data from domestic consumers for settlement purposes, unless the

[15] For more details about the transition period see chapter 7 of the consultation document.
[16] The advantages and disadvantages of making non-aggregated HH data available to central settlement systems are discussed in chapter 4 of the consultation document. The decision on where and how the non-aggregated data is to be held has not yet been made. The data could be held in a single central hub or in multiple stores.

consumer opts out. Under both options 2 and 3, we propose that they should collect daily resolution data from these opted-out domestic consumers for settlement purposes.

2.7. We are consulting on this proposal within the consultation document, including asking for views on what would be a proportionate arrangement for existing customers who already have their smart meters. We want to make sure that the framework for accessing data balances consumer privacy considerations with the need to ensure that as much high-resolution data as possible is entered into the system to achieve the benefits of the reforms, and that existing smart meter customers are treated proportionately.

2.8. We have also said that any data collected for settlement purposes can be used by suppliers for forecasting, in order for them to predict their future purchasing liabilities.

2.9. We take this opportunity to remind stakeholders that parties in possession of personal data must comply with data protection law, including the General Data Protection Regulation (**GDPR**).

MHHS compared to elective HHS

2.10. In the Outline Business Case (**OBC**), we said that supplier incentives under the elective arrangements were unlikely to be strong enough to facilitate a transformational shift in consumption patterns.[17] We cited the following reasons:

- information asymmetries allow suppliers to 'cherry pick' the customers they try to influence, particularly in a market with significant levels of customer disengagement
- suppliers would incur significant upfront costs in changing IT systems and operations

[17] The CMA also expressed this view in its 2016 Energy Market Report.

- suppliers would be exposed to new risks (for example, in forecasting customer demand accurately without Profile Classes, and whether customers would take-up any new products and services) and this could deter innovation, and

- not all the benefits of HHS flow directly to suppliers, which makes the incentives on suppliers to introduce HHS weak relative to the potential benefits for consumers, and justifies a market-wide approach.

2.11. Achieving the higher end of the potential benefits presented in this draft impact assessment (**IA**) would likely require a critical mass of consumers being HH settled, for Time of Use (**ToU**) products and other innovations to be commonplace and for consumers to shift their consumption from peak periods as a result. In reaching a conclusion about whether this could happen without MHHS, we have considered recent developments in the elective market and suppliers' responses to our 2019 Request for Information (**RfI**).

2.12. Elective HHS enables those firms wanting to be early movers and innovators in this market to develop new products and services. However, as at January 2020 less than 1% of domestic metering points were registered as HH sub-100kW domestic. Of the suppliers that responded to our RfI, only a small number said they were offering tariffs facilitated by HHS. No other supplier that responded said that they would develop HHS-facilitated tariffs in the short term. A small number of suppliers said they would consider developing these tariffs in the future if long term elective HHS were to continue under BAU, but only if there were a commercial case for these products (for example, if there were an increase in consumers demanding ToU tariffs). No other supplier that responded said they would develop HHS-facilitated tariffs without Ofgem making a formal decision to introduce MHHS.

2.13. One supplier said MHHS would remove barriers to further innovation that exist under the elective arrangements, including an absence of industry-wide gain/loss processes for half-hourly settled customers and a lack of effective performance oversight. The supplier suggested there should be guidance for suppliers and agents and new, bespoke governance processes. To be clear, though, the supplier does not regard these improvements as a substitute for MHHS. We agree. Improvements to the elective process would not address the main barrier to innovation, which is that suppliers do not face accurate signals about the cost of serving their customers throughout the day. MHHS is necessary to remove that barrier.

2.14. Several suppliers noted that consumer demand would drive their product innovation. We consider that consumer demand for innovative products is likely to be higher under MHHS than under the elective arrangements. One supplier noted the importance of changes under the Electricity network access and forward-looking charges Significant Code Review (**SCR**) in determining the direction of their product innovation.

2.15. We conclude that elective HHS will deliver insufficient load shifting to produce the scale of system-level benefits we seek. Without MHHS it is unlikely that the disengaged (or less engaged) would be given a chance to reduce peak time demands via Time of Use tariffs, smart appliances and battery storage. Similarly, MHHS is expected to facilitate some of the options that are under consideration in the Electricity network access and forward-looking charges SCR.

2.16. Finally, there are process and efficiency reasons for introducing MHHS rather than relying on incrementally increasing HHS uptake under the elective arrangements. A number of the direct benefits, such as shorter settlement timeframes and removing the profiling arrangements, can only be realised with a significant number of HH-settled customers. MHHS would avoid having to run half-hourly and non-half-hourly settlement systems concurrently. Similarly, MHHS avoids any potential unintended consequences where customers change between HH and non-half-hourly (**NHH**) settlement systems.

2.17. This qualitative assessment strongly suggests that MHHS is the best way to deliver the project objectives. The following sections evaluate the costs and benefits of options 2 and 3.

3. Monetised direct costs

Section summary

In this section we set out our analysis of the monetised direct costs of introducing market-wide half-hourly settlement (**MHHS**) under option 2 (our preferred option) as compared with retaining the existing elective arrangements.

Based on responses to the Request for Information (**RfI**) and other evidence from stakeholders, we have estimated the costs under option 2 that could be borne by industry participants, including suppliers, supplier agents, the DCC, ELEXON, distribution network businesses, the Electricity System Operator and the Low Carbon Contracts Company. We include cost tables setting out the monetised impact of option 2. For each stakeholder type, we also describe how their costs might differ under option 3 (and we quantify those costs where possible).

At the end of the section we summarise total direct costs and, acknowledging the uncertainty involved, present a table of cost ranges for option 2.

Approach to assessing direct industry costs

3.1. We expect industry to incur costs in implementing and operating either MHHS option. We have classified these costs as transitional costs, which relate to the investment needed to implement the changes, or ongoing costs for operating the new settlement arrangements over and above 'business as usual' operating costs. The costs will vary for each market participant.[18]

3.2. Transitional costs include the following:

[18] While we expect industry to incur an overall net cost, these are likely to be distributed unevenly between individual participants. In some areas, we expect industry costs to reduce against the counterfactual (for example, the savings that can be expected to arise from improved forecasting of customer demand, or from changes to the settlement timetable). These benefits are incorporated within the overall costs reported in this chapter.

- upgrades to existing industry participants' IT capabilities so that they are able to interact as necessary with the new Target Operating Model (**TOM**), including the costs of migrating Meter Point Administration Numbers (**MPANs**) to the new settlement arrangements

- costs arising during and immediately after the migration period to monitor the new arrangements in live operation and deal with unexpected problems experienced after the end of migration[19] to the new settlement arrangements (excluding programme costs)

- programme costs (central delivery assurance, detailed programme design and engagement costs, including for Ofgem).

3.3. Ongoing costs include the following:

- operation of the TOM

- costs for industry participants to maintain and operate their new IT arrangements, including maintaining an acceptable level of IT resilience

- changes to staffing requirements to manage the new settlement processes

- any reduction in costs for increased efficiency in the processes required.

3.4. We do not propose to include, as part of the central estimate of costs, the costs of suppliers developing, marketing and billing for new products and services after MHHS comes into effect. However, we consider these costs as part of a sensitivity analysis, and note that these extra costs might be necessary to achieve the higher end of the potential benefits.

Accounting for uncertainty

3.5. We recognise that MHHS would impose significant costs on the industry. We have made extensive efforts to ensure we understand these costs, and their drivers, as

[19] This is the point by which all Meter Point Administration Numbers (MPANs) must be settled under the TOM.

well as possible. Where the costs have been difficult to obtain or verify we have adopted a consciously cautious approach to ensure that we are, as far as possible, mitigating the risk of underestimating these. In particular, where it has not been possible to get a quantitative answer to a question in the RfI from a particular stakeholder, we have sought to fill in the gaps by estimating the costs using data from similar stakeholders.

3.6. We acknowledge the difficulty for industry participants of calculating the exact costs of implementing MHHS at this stage of TOM development. To take account of this, we gave stakeholders the option of qualifying their quantitative responses to the RfI using an uncertainty margin, which we could use to calculate a cost range.

3.7. We are publishing the level of uncertainty reported by stakeholders in the form of a cost range to give an idea of the level of uncertainty we are facing and how it compares to our central estimate of costs. We present and discuss this analysis at the end of this section (see paragraphs 3.88-3.90).

Net Present Value (NPV) calculations

3.8. In line with Green Book guidance,[20] we have calculated the NPV by applying a 3.5% discount rate to real values (using GDP deflator to remove inflation effects). We have used the year 2018 as the base year to calculate real prices to ensure comparability with the figures published in our Outline Business Case (**OBC**) for MHHS. All values are discounted to 2018. Unless otherwise stated, we have applied the same methodology to both costs and benefits.

3.9. We have taken the following approach to investment periods to calculate the total costs (in NPV terms). Transitional costs (one-off costs) are divided equally across the transition period. Under option 2, this period would be 2021-2024. Ongoing costs (new BAU costs) start after the migration phase is finished and are accounted for over a 20-year period. Under option 2, this period would be 2025-2045. All costs are discounted using the above methodology.

[20] See 'The Green Book: Central Government Guidance on Appraisal and Evaluation.'

3.10. The length of the transition period is one of the key differences between options 2 and 3. It will affect the duration of the transitional costs and when we should start computing annual ongoing costs (new BAU costs). It will therefore affect the total costs (in NPV terms). To ensure comparability between the different options, costs (in NPV terms) are always calculated for the period 2021-2045.

3.11. Under option 3, the transition period of approximately 5 years would mean that annual ongoing costs start in 2026, a year later than under option 2. To calculate the total costs (in NPV terms) under option 3, we divided transitional costs equally across the transitional period of approximately 5 years (2021-2025). Ongoing (new BAU) costs are accounted for over the period 2026-2045. We show how total costs change under option 3 at paragraphs 3.92-3.98.

Suppliers

Option 2 – MHHS for import and export Meter Point Administration Numbers (MPANs) with a transition period of approximately 4 years

3.12. The table below summarises the estimated net costs of option 2 for suppliers (central estimate). It includes adjustments to account for those suppliers that did not respond to our RfI and adjustments we have made to some supplier responses.

3.13. We have included some costs incurred by software providers that provide settlement-related services to suppliers.[21] The data is presented as a total and as a cost breakdown by categories of costs. In estimating supplier costs, we have sought to take appropriate account of recent corporate transactions in the sector.

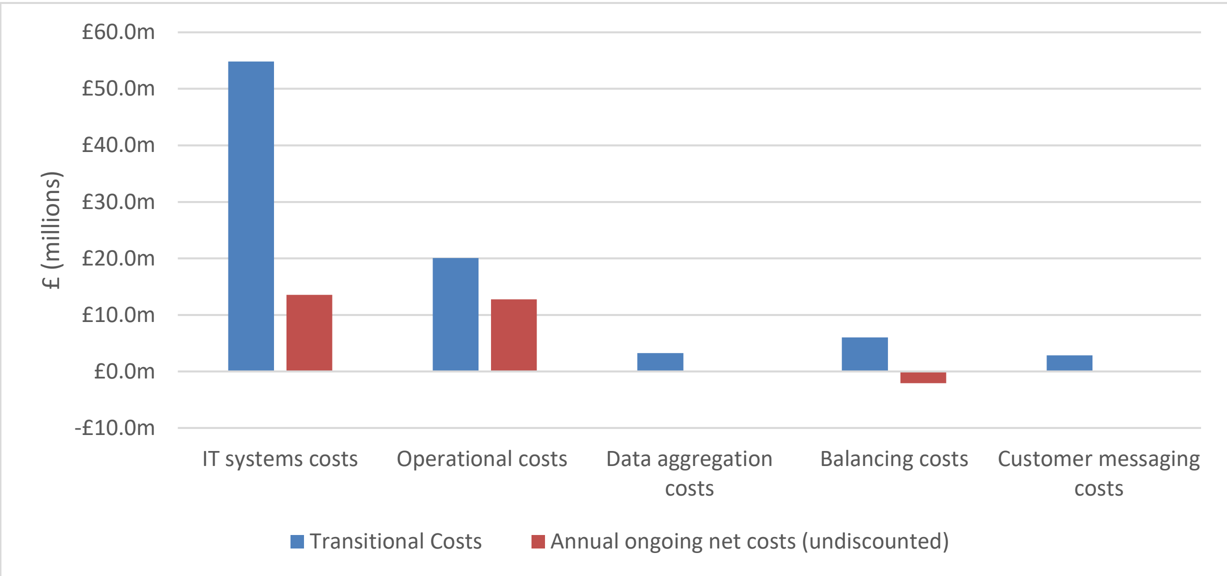
[21] As with the data from suppliers, some adjustments were required to account for those software providers that did not respond to our RfI.

Table 1: Estimated net direct costs for suppliers of option 2 (£ millions)

Costs MHHS option 2	Transitional costs (undiscounted, £2019)	Annual ongoing net costs (undiscounted, £2019)	Total net costs (2021-2045), 2018 NPV
IT systems costs	£54.9m	£13.5m	
Operational costs	£21.5m	£12.8m	
Data aggregation costs	£3.3m	£0.0m	
Balancing costs	£6.0m	-£2.1m	
Customer messaging costs	£2.8m	£0.0m	
Total costs	**£88.5m**	**£24.2m**	**£358.4m**

3.14. The figure below shows the undiscounted cost breakdown for suppliers of option 2.[22]

Figure 1: Undiscounted net direct costs for suppliers of option 2 (£ millions)



3.15. For all MHHS options, suppliers would need to invest in new IT systems and/or upgrade existing IT systems to interact with the new central settlement system and TOM services. Operational costs would increase, mainly due to the increase in the

[22] In the RfI we sought details about any impacts of MHHS on suppliers complying with their obligations under relevant environmental schemes. In the guidance to the RfI, we asked suppliers to assume that the current schemes remained in place rather than any future schemes. This includes Contracts for Differences, the Renewable Obligation, Feed-in Tariffs and the Energy Company Obligation. No supplier reported costs under any of these schemes arising from MHHS.

complexity of the consumption data that suppliers would need to manage. Under any MHHS option, suppliers would also incur balancing costs (relating to the number and cost of their balancing actions), and customer messaging costs (arising from the need to inform customers about their data sharing options).

3.16. On the other hand, suppliers should make cost savings as a result of having more detailed consumption data and improvements in energy consumption forecasting (which would, for example, reduce the exposure to imbalance costs).

3.17. There was considerable difference between suppliers on their cost drivers. This depended on factors such as the flexibility and cost of amending existing systems, design decisions, and different levels of efficiency in implementing and operating new processes. However, we outline below some general trends about cost drivers.

Transitional costs

3.18. The main cost driver is upgrading existing and/or buying new IT systems so as to operate under the new settlement arrangements. Supplier responses varied as to which IT processes would need substantial investment. Some suppliers cited costs relating to the removal of profiling activities and change of measurement class of non-half-hourly (**NHH**) MPANs. Others emphasised the costs relating to collecting and processing metering data. A few highlighted costs arising from changes to demand forecasting activity.

3.19. Transitional operational costs were the second biggest cost category, though less than half the total for IT costs. Supplier responses again varied considerably, for example in relation to balancing costs. The two most costly processes were managing customer contract communications and demand forecasting.

Annual ongoing costs

3.20. In aggregate, reported IT and operational ongoing costs were almost the same. However, this masks significant differences among larger suppliers about which category of costs would be larger. Some suppliers expected to make net operational savings.

3.21. The main drivers of ongoing IT costs are collecting, transferring and holding HH consumption data, and demand forecasting activities. The main drivers of ongoing operational costs are transferring and processing HH metering data, and managing customers' contract communications. Some suppliers reported expected net cost savings from demand forecasting activities due to the improvement of forecasting tools using more granular consumption data. However, they noted higher uncertainty around the expected cost savings compared to the expected costs.

3.22. Respondents did not anticipate any net ongoing costs for balancing, customer messaging or meeting environmental scheme obligations. Some expected net ongoing savings from balancing costs due to more accurate consumption data.

3.23. Some suppliers with 'in-house' agents cited an increase in ongoing costs as a result of our proposed changes to the settlement timetable.[23] These costs related mainly to making more frequent manual meter reads where a consumer is not on a smart meter and because of an assumed requirement for more timely fault resolution. We expect the Balancing and Settlement Code Performance Assurance Framework (**BSC PAF**) to set performance targets taking into account factors such as the number of traditional meters remaining and a reasonable level of meter faults. Accordingly, we have not accepted all the cost increases estimated in this area by suppliers with in-house agents. Most suppliers did not provide evidence about the impact of making non-aggregated data available to central settlement systems. Those that did (mainly those with in-house agents) thought that the ongoing costs of such a model would be similar to those experienced in the market today.

3.24. We have not received evidence to date about the ongoing costs that could be incurred by software providers that provide settlement-related services to suppliers. However, we have sought to estimate this, and some ongoing costs have been included in the total costs. Should we receive evidence, we will consider it carefully and adjust our cost estimates as appropriate.

[23] Our settlement timetable proposals are described in chapter 5 of the consultation document.

Option 3 - MHHS for import MPANs only with a transition period of approximately 5 years

3.25. In this section of the draft impact assessment (**IA**), we summarise the evidence that we have received from suppliers about the impact of:

- including export MPANs, or not, within these reforms
- introducing MHHS for export MPANs at the same time as for import MPANs, and
- introducing MHHS over a different transition period to that proposed in option 2.

Import/export MPANs

3.26. In response to our RfI, three large suppliers said the costs of settling export MPANs half-hourly would either be the same or very similar to the per MPAN costs of MHHS for imports. One larger supplier said that at present its systems for export metering are largely manual. Two other suppliers said they could not quantify the impact of settling export MPANs on a HH basis because they did not offer export tariffs at the time of the RfI.

3.27. Based on the RfI responses we received, we estimate that implementing MHHS for export MPANs will impose transition costs of £4.15 million on suppliers. However, a small number of suppliers that responded to the RfI reported ongoing costs or savings, leading to estimated overall savings of £200,000 per annum, attributable to factors including improved forecasting. We did not receive many responses from smaller suppliers but expect that many currently either have manual processes for export or do not serve export customers.

3.28. Under the Smart Export Guarantee (**SEG**), suppliers with over 150,000 domestic customers have been required to offer export tariffs since January 2020. The launch of the SEG should prompt many more suppliers to register export MPANs before we introduce MHHS. Two suppliers said that because of this it would be reasonable to introduce MHHS for export MPANs at the same time as for import MPANs. Three large suppliers said that there would likely be savings if we brought in MHHS for import and export at the same time. Several other suppliers reported that the relative implementation timings for import and export would have little or no impact on their transitional or ongoing costs. However, one smaller supplier said that, as they believe they would need a separate system for export MPANs, it would be helpful to introduce MHHS for export 2 years after import MPANs.

Transition period

3.29. In our RfI, we asked suppliers to assume an overall transition period of 4 years, based on 3 years to implement the TOM and 1 year to migrate MPANs. We asked how their costs might change assuming a 3- and a 5-year transition period instead. The majority of suppliers that responded to the RfI did not identify significant differences in costs whether the transition period lasted 3, 4 or 5 years.

3.30. For some suppliers, though, the main issue was a potential lack of dedicated resources while the industry was seeking to implement faster switching. They have said that a rapid transitional period could increase costs on suppliers as a result of having to procure additional resources to handle the extra work during 2020 and 2021. One supplier suggested that implementation costs could increase by as much as 25% compared to a transition period of 4 years. If additional resources are not committed to MHHS, we have been told that a rapid transition over 3 or 3.5 years could affect the design quality and overall robustness of the new settlement arrangements.

3.31. Two suppliers said that a transition to MHHS over 5 years might allow other industry changes to be bedded in, and so make the transition more straightforward. One other supplier expressed concern about resource availability in the short term but said a 5-year transition period would significantly increase uncertainty. For this supplier a 4-year period would strike the right balance.

3.32. A third supplier felt that the system changes could be delivered in a 12-month period and that there were benefits to be realised from an early implementation thanks to the improved forecasting accuracy. However, that supplier also noted the risks of migrating customers too early and that a longer implementation timeline could lead to a more efficient delivery.

Independent supplier agents

Option 2 – MHHS for import and export MPANs with a transition period of approximately 4 years

3.33. The table below summarises estimated net costs of implementing option 2 for independent[24] supplier agents. Under option 2 (and option 3), supplier agent functions would shift from the current ones of meter operator, data collector and data aggregator to new ones of metering and data service provider. Aggregation for the purposes of settlement would no longer occur outside central settlement systems. Instead, non-aggregated data would be made available to central settlement systems for the purposes of calculating the settlement imbalance.

3.34. We did not receive costs from all independent supplier agents in the market. In order to derive an approximate set of costs for all the independent supplier agents in the market, we have applied a 25% increase to the IT and operational costs reported to us. We believe that this approach is conservative and may even overstate the costs to a small extent.

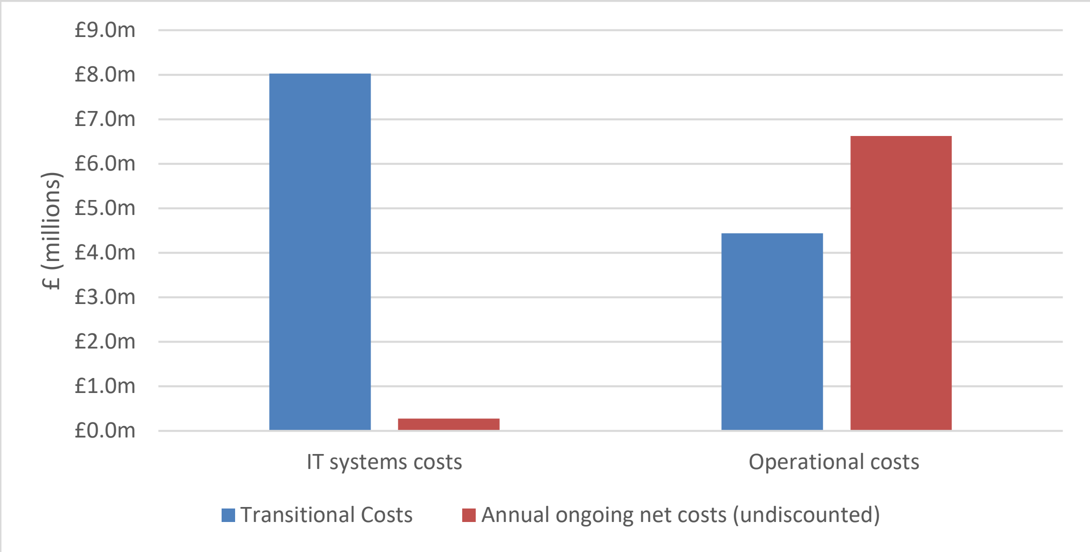
Table 2: Estimated net direct costs for independent supplier agents of option 2 (£ millions)

Costs MHHS option 2	Transitional Costs (undiscounted, £2019)	Annual ongoing net costs (undiscounted, £2019)	Total net costs (2021-2045), 2018 NPV
IT systems costs	£8.0m	£0.3m	
Operational costs	£4.4m	£6.6m	
Total costs	**£12.5m**	**£6.9m**	**£91.4m**

3.35. Figure 2 below breaks down the undiscounted costs for independent supplier agents.

[24] 'In-house' supplier agent costs are covered under the supplier costs section.

Figure 2: Undiscounted net direct costs for independent supplier agents of option 2 (£ millions)



3.36. There was general agreement among supplier agent responses about the main ongoing cost drivers: these related to the operational costs of processing and validating meter data, and collecting, storing and transferring that data. Supplier agents also noted (alongside suppliers with in-house agents) that shortening the settlement timetable would increase meter reading costs as agents adopt more intensive dialling and/or site visit practices. As we have already said, we expect the BSC PAF to set performance targets taking into account factors such as the number of traditional meters remaining and a reasonable level of meter faults.

3.37. The main transitional costs relate to IT system changes in order to handle the increased data and communications required.

3.38. Under options 2 and 3, supplier agents would have to make non-aggregated data available to central settlement systems. This can be expected to have an impact on supplier agent revenues, as they currently carry out the data aggregation role. We received limited quantitative information on the impact on revenues from most respondents. However, we have not included this in the ongoing costs for these options as the loss of revenue to supplier agents does not result in an additional cost to consumers.

3.39. We do not therefore propose to include the future and potential future supplier agents' lost revenues in the total policy costs. However, we have included some transitional costs of stopping the data aggregation services (such as the cost of renegotiating existing contracts). Chapter 3 of the consultation document discusses the broader advantages and disadvantages of making non-aggregated data available to central settlement systems, and includes more information on the costs associated with this, including consideration of the economic impact on supplier agents.

3.40. If aggregation for settlement purposes were to continue to occur at the supplier agent level, supplier agents thought data aggregation costs would be similar to the costs of aggregating data today, but that there may be a small one off cost to upgrade the hardware. They thought the costs of transferring data, in comparison to options 2 and 3, would be slightly lower as the data would be aggregated prior to being transferred to central settlement systems.

Option 3 - MHHS for import MPANs only with a transition period of approximately 5 years

3.41. Supplier agents who responded said that their systems could already handle export MPANs so the only additional costs for introducing MHHS for export MPANs would be the costs associated with serving the additional export meters.

3.42. All the supplier agents that responded to the RfI stated that the duration of the transitional period would have no impact on their operational costs. Most supplier agents took a similar view in relation to transitional costs. However, one supplier agent thought that implementing the IT changes in 2 years would not be feasible and would likely increase transitional costs by 50%.

Data Communications Company

Option 2 – MHHS for import and export MPANs with a transition period of approximately 4 years

3.43. The Data Communications Company (**DCC**) maintains the national infrastructure that connects smart meters to industry users such as suppliers and network operators, under licence.

3.44. SMETS2 meters are enrolled onto the DCC's national communications network when installed and commissioned. SMETS1 meters use separate communications and data services which have been procured by individual energy suppliers. The DCC is required to develop a communications service for at least 99% of the SMETS1 population and enrolment of SMETS1 meters into the national network has begun. These SMETS1 meters are being enrolled remotely, without the consumer needing to take any action. BEIS has proposed that suppliers be required to complete this process by the end of 2021.

3.45. In our RfI we asked the DCC to estimate the cost of two scenarios for data retrieval from smart meters under MHHS:

- 1 - Retrieving one day of HH metering data, daily, from every smart meter, and
- 2 - Retrieving one month of HH metering data, daily, from 1 in 30 smart meters.

3.46. The DCC provided costs for scenario 1. The DCC's view is that the scenario 2 would cost at least double the first scenario and would be less practical. The DCC believes that pulling a month's worth of data, as opposed to a day's worth, is more likely to increase the failure rate of service requests. This will in turn result in more service requests being required to retrieve the data. In this draft IA, we have used the costs provided by the DCC for scenario 1. We expect to include costs associated with scenario 1 in the Final IA unless we receive any evidence from stakeholders or recommendations from the Architecture Working Group (**AWG**) to the contrary.

3.47. The costs provided by the DCC under this scenario assume that any new services supported by the TOM, such as vehicle-to-grid services and peer-to-peer trading, have their data requirements met by the MHHS service and do not result in additional load being placed on the DCC's systems.

3.48. The DCC has estimated the net costs to implement option 2 to be in the general region of £10 million pounds. The costs include both direct programme resource costs and additional necessary incremental costs. The costs are associated with scenario 1 for the DCC and its service providers (retrieving one day of HH metering data, daily, from every smart meter). The DCC is currently working on the underlying detail of the solution and therefore this is a high-level estimate which we expect to become more accurate in the Final IA.

3.49. The one-off transitional costs include those associated with implementing the necessary architectural changes, responding to any changes to industry specifications and upgrading the communications hub firmware. The DCC estimates that these costs would be absorbed over an 18-month period. The ongoing costs (which the DCC estimates to be in the low millions of pounds) reflect the additional costs necessary to operate the new infrastructure.

Option 3 - MHHS for import MPANs only with a transition period of approximately 5 years

3.50. The DCC has stated that it can deliver the changes required within two years, though costs associated with programme overheads could increase accordingly if longer delivery timescales than this are required. It is noted that a Smart Energy Code (**SEC**) modification will also be required alongside any DCC changes.

3.51. We do not have figures about any impact on the DCC of including export meters as part of MHHS. We will work with the DCC to improve our understanding of this point in advance of the Full Business Case (**FBC**).

ELEXON

Option 2 - MHHS for import and export MPANs with a transition period of approximately 4 years

3.52. ELEXON estimates that for option 2 it would face some transitional costs (in the low to mid millions of pounds), but these would be balanced by ongoing annual cost savings, leading to potential net cost savings overall.

3.53. The main cost drivers identified by ELEXON are the one-off development costs for the IT system and process changes required to implement the new TOM services, as well as the one-off costs of decommissioning the existing NHH services.

3.54. For ongoing costs, ELEXON believes there will be an ongoing net benefit of decommissioning the NHH services (processes as well as systems) and replacing them with the new TOM services. ELEXON also identified potential cost savings which might arise from the removal of NHH services, such as no longer being required to send Market Domain Data and profiling data through the Data Transfer Network (**DTN**). This would significantly reduce ELEXON's DTN traffic volumes. ELEXON also identified cost savings because the current HH agents and systems are less costly to assure/audit compared with the NHH agents and systems.

3.55. The most significant potential ongoing cost increase identified by ELEXON would arise if there were a need to extend the technical assurance service for non-smart meters (with current transformers) or advanced meters. However, ELEXON believed it was unlikely that this would be required.

3.56. If aggregation continued to take place outside the Balancing and Settlement Code (**BSC**) central systems, ELEXON believes there would be little cost difference compared to the preferred TOM. The design of the load shaping service as part of the TOM would require central systems to process large amounts of meter point level HH data so as to create the load shapes. There would, therefore, be no significant cost saving from storing less data if data were to be aggregated outside central systems for settlement. In addition, other industry changes, notably BSC Modification Proposals P344 (Project TERRE), P375 (behind the Meter) and P379 (multiple Suppliers), mean BSC systems will need to be able to process meter point level data regardless of where data is aggregated for settlement purposes.

Option 3 - MHHS for import MPANs only with a transition period of approximately 5 years

3.57. In relation to its own systems, ELEXON does not believe there would be any operational difference between MHHS for import and export MPANs. ELEXON has told us that its systems would not, therefore, require significant additional changes if we decide to mandate HHS for export.

3.58. ELEXON believes it will take approximately two years to design, build and test the required changes to BSC central settlement systems. ELEXON believes that it will be in a position to start this process at the beginning of 2021. ELEXON does not believe that any cost savings would arise from taking longer than two years to complete its new central settlement system. However, ELEXON notes that a longer transition period would delay the benefits of MHHS and would potentially increase the transition costs if there were further support of industry testing with participants and service providers.

Distribution Network Operators (DNOs)

Option 2 - MHHS for import and export MPANs with a transition period of approximately 4 years

3.59. The table below summarises the estimated net costs of option 2 for DNOs and Independent Distribution Network Operators (**IDNOs**).

Table 3: Estimated net direct costs for DNO/IDNOs of option 2 (£ millions)

Costs of MHHS option 2	Transitional Costs (undiscounted, £2019)	Annual ongoing net costs (undiscounted, £2019)	Total net costs (2021-2045), 2018 NPV
Operational costs: Export	£1.3m	£0.1m	
IT costs and other operational costs	£0.6m	£0.0m	
Total costs	**£1.9m**	**£0.1m**	**£2.2m**

3.60. We have been told by DNOs and IDNOs that their main cost drivers are one-off costs relating to registering export MPANs for customers that do not currently have one and changes to the DURABILL and Metering Point Registration System provided by St. Clements (which would be shared amongst all DNOs and IDNOs). The transitional costs associated with registering export MPANs are £1.2m, accompanied by £50,000 of ongoing costs associated with the increased volume of export MPAN registrations. Separately, we have also been told that costs will likely be incurred for the modification of associated downstream and upstream systems as well as costs associated with programme engagement and testing. We have not been provided any quantitative values for this, but we would welcome such evidence.

3.61. We did not receive much quantitative information from IDNOs but they identified similar cost drivers as DNOs. The costs to IDNO of changes to the DURABILL and Metering Point Registration System have been accounted for, but we have not been able to account for the costs to IDNOs of registering export MPANs. We welcome more information from IDNOs on their costs.

3.62. Many network operators felt they did not have enough information to provide costs for Unmetered Supply (**UMS**) customers, and raised concerns about the costs to NHH UMS customers of moving to HH regimes. One area of concern was the frequency of inventory updates required. Currently, HH UMS customers update their inventories monthly with the network operator and NHH UMS customers update their inventories annually. One network operator estimated that if its entire UMS portfolio were to move to monthly inventory updates that would cost in the region of tens of thousands of pounds per annum.

3.63. Network operators also raised concerns about charges that could potentially be levied on small UMS customers if they were to be settled half-hourly. Currently, half-hourly data for HH UMS customers is created by their meter administrators. This is a relatively manual process that requires significant interaction with the customer. One meter administrator estimates that the customer is charged thousands of pounds per annum for this service.

3.64. For NHH unmetered customers, unmetered supplies operators and data aggregators apply similar profiling processes as for metered customers to their supplier's data. One meter administrator estimates that the data aggregator charges the supplier an annual fee in the region of 10s of pounds per MPAN for this service. If current NHH unmetered supply customers were to be charged under the current HH regime, network operators suggest that these charges could be significantly more than their total energy bill. We do not believe that monthly inventory checks or the current half-hourly data aggregators' (**HHDAs**) charging regime would be proportionate for smaller UMS customers. We will therefore ask the Code Change Development Group (**CCDG**) to explore a proportionate solution for smaller UMS customers.

Option 3 - MHHS for import MPANs only with a transition period of approximately 5 years

3.65. Under option 3, DNOs and IDNOs would avoid £1.2m of transitional costs and about £50,000 of ongoing costs associated with increased export MPAN registration.

3.66. One network operator felt that implementation timing would have an effect on them and/or on their costs, while most other network operators believed there would be no effect on them. However, some DNOs highlighted that the readiness of other parties would be the main influence on how long it would take the network operators to implement the changes required for MHHS (specifically, that suppliers would need to provide them with the information required to register export MPANs in a timely manner).

ElectraLink

3.67. ElectraLink provides the data communication infrastructure necessary to facilitate electricity retail settlement. ElectraLink does this through the Data Transfer Service (**DTS**), part of the Energy Market Data Hub (**EMDH**).

Option 2 – MHHS for import and export MPANs with a transition period of approximately 4 years

3.68. MHHS will significantly increase the volume of settlement-related data traffic that will be exchanged between parties within the system. ElectraLink estimates that monthly data traffic could increase by approximately 2,600 GB (over 100 times the volume of half-hourly (**HH**) data currently being processed) if all MPANs in the market were settled half-hourly. Any data transfer network must be able to accommodate that extra traffic securely and cost effectively.

3.69. Under MHHS, one option could be to expand ElectraLink's existing DTS communications network as market participants are already connected to it. ElectraLink believes that the DTS platform is suitably scalable to enable it to accommodate the extra data traffic cost-effectively and with minimal disruption to industry.

3.70. We have not decided which communications solution should be used to transfer data under the TOM. Here, we cite the estimated costs to ElectraLink of using its communications network in order to indicate the magnitude of costs that may be involved. There are other possible solutions to consider. The AWG will consider the logical requirements for transferring data under the TOM and consider options accordingly. Cost-effectiveness and data security will be important considerations and therefore we expect any communications solution should be in the same order of magnitude as the ElectraLink costs. The AWG will submit recommendations to us later in 2020.

3.71. We have estimated the net costs for ElectraLink of option 2 as less than £10 million (2018 NPV). For context, the current ElectraLink DTS for all NHH and HH market processes including switching, metering and settlement costs industry approximately £7m per year. This highlights the fact that most of the underlying system costs are largely fixed. The incremental increase in costs relative to the status quo are due to the need to add additional data storage, additional load balancing capability to manage traffic peaks, and additional communication capacity. ElectraLink states that the operational costs of implementation will not change between a 2-year or a 4-year implementation period.

Option 3 - MHHS for import MPANs only with a transition period of approximately 5 years

3.72. ElectraLink noted in its RfI response that the operational costs of implementation would not vary across the different transitional periods. ElectraLink also noted that there would be no difference in implementation costs if export were included or not.

Electricity System Operator (ESO)

Option 2 - MHHS for import and export MPANs with a transition period of approximately 4 years

3.73. The ESO said it could incur costs as a result of removal of NHH methodologies, which could impact on charging and billing systems. We do not currently have firm estimates for any of these potential costs, but the ESO has suggested an initial indicative estimate of low millions of pounds.

3.74. The ESO also said that costs could arise if it had to make changes to its charging and billing system as a result of Ofgem's Electricity network access and forward-looking charges Significant Code Review (**SCR**), which may be enabled by our MHHS decision. These changes would be necessary, said the ESO, if Ofgem required ELEXON to change the frequency and format of data that it sends to them for calculating charges. We expect to be able to provide a firmer estimate of these costs in our Final IA.

Option 3 - MHHS for import MPANs over a transition period of approximately 5 years

3.75. The ESO has indicated that the estimate provided for option 2 would not vary with the implementation period or whether or not export is included in MHHS.

Other Code administrators

3.76. We have not received much quantified information about any additional costs that could be incurred by other code administrators, as a result of any decision to introduce MHHS (whether under option 2 or 3).

3.77. We believe some costs will be incurred by the code administrators impacted by changes (such as the code administrators for the Distribution Connection and Use of System Agreements (**DCUSA**), the Smart Energy Code and the Master Registration Agreement) but we think these costs would be minimal. For example, ElectraLink, the code administrator for the DCUSA, has stated that it would incur one-off costs associated with legal text changes to the DCUSA. Some of these would be absorbed in ElectraLink's business as usual change processes, whilst some may require extra funding. We included an estimate for the extra funding in our sensitivity analysis.

Low Carbon Contracts Company (LCCC)

3.78. The LCCC is a private limited company wholly owned by BEIS. It was created to assist in the delivery of the government's Electricity Market Reform programme.[25] Its main role is to oversee the participation of low carbon generators within the Contracts for Difference process. This involves managing the contracts themselves and administering the levy on suppliers that funds the payments to generators.

Option 2 – MHHS for import and export MPANs with a transition period of approximately 4 years

3.79. The LCCC said it would incur some one-off costs as a result of MHHS, due mainly to the need to change processes if the settlement timetable is shortened as proposed. The LCCC also said it would incur no incremental ongoing costs as part of the reforms.

3.80. The LCCC provided two transitional cost estimates. These were:

[25] Details of the Electricity Market Reform programme can be found on the Ofgem website here.

- Estimate 1 – LCCC systems require development to align with the new 4-month Final Reconciliation (**RF**) settlement timetable. No data changes are required. The LCCC estimated the costs to be in the low hundreds of thousands of pounds.

- Estimate 2 – Assumes a requirement to create and handle a separate settlement timetable, and some changes being required to data associated with delivery. The LCCC estimated the costs to be in the high hundreds of thousands of pounds.

Option 3 - MHHS for import MPANs only with a transition period of approximately 5 years

3.81. The LCCC does not believe that costs would change materially under option 3.

Programme costs

Programme costs, including programme management arrangements

3.82. We define programme costs as the additional costs to industry of participating and supporting Ofgem in the design and delivery of the new settlement arrangements under a range of possible governance arrangements. At present, the estimated costs include establishing and running a central Programme Management Operation (**PMO**) and assurance function, and a potential Systems Integrator function.

3.83. We did not explicitly request information about programme costs in the RfI last year. We therefore assume that industry stakeholders have not yet sought to estimate these costs. To avoid any risk of double counting, it would be helpful if any stakeholder that did include these costs in their RfI response could provide details.

3.84. As a first step towards establishing the likely scale of MHHS programme management costs, we have looked at similar costs associated with the Switching Programme and Project Nexus and adjusted them appropriately. Even with an adjustment, we think this should be the upper end estimate and we expect the actual programme costs for MHHS to be lower than this estimate. So as not to unduly influence any potential procurement of the PMO, programme party coordinator, system integrator and assurance services we have included these estimated costs with the other central costs reported in this chapter. We will refine these programme management costs as we progress towards the FBC, and they will be included in our Final IA.

3.85. Most programme management costs would be incurred during the implementation phase. However, there could be costs connected with resolving issues after full transition. We recognise that, if there were to be a significant problem at implementation, the consequences could be far reaching and costly for industry and consumers. We are aware of these potential impacts and will put in place delivery and assurance arrangements commensurate with this risk.

Ofgem costs

3.86. For options 2 and 3, Ofgem would incur transitional costs of continuing to manage the programme through to its conclusion. We will set these out in our Final IA.

Summary of direct costs and ranges

Option 2 – MHHS for import and export MPANs with a transition period of approximately 4 years

3.87. The tables and figures below summarise the estimated costs that each type of market participant would incur under option 2.

Table 4: Estimated net direct costs by stakeholder type of MHHS option 2 (£ millions)

Stakeholder type	Transitional costs (£2019, undiscounted)	Annual ongoing net costs (£2019, undiscounted)	Total net costs (2021-2045), 2018 NPV
Suppliers	£88.5m	£24.2m	£358.4m
Supplier Agents	£12.5m	£6.9m	£91.4m
DNOs/ IDNOs	£1.9m	£0.1m	£2.2m
Central costs[26]	£39.9m	£0.6m	£40.6m
Total costs	**£142.7m**	**£31.8m**	**£492.5m**

[26] This includes costs for the DCC, ELEXON, ElectraLink, the ESO and the LCCC. It also includes programme and post-implementation costs. In the Final IA we will add Ofgem costs to this category.

Figure 3: Proportion of estimated net direct costs by stakeholder type, option 2

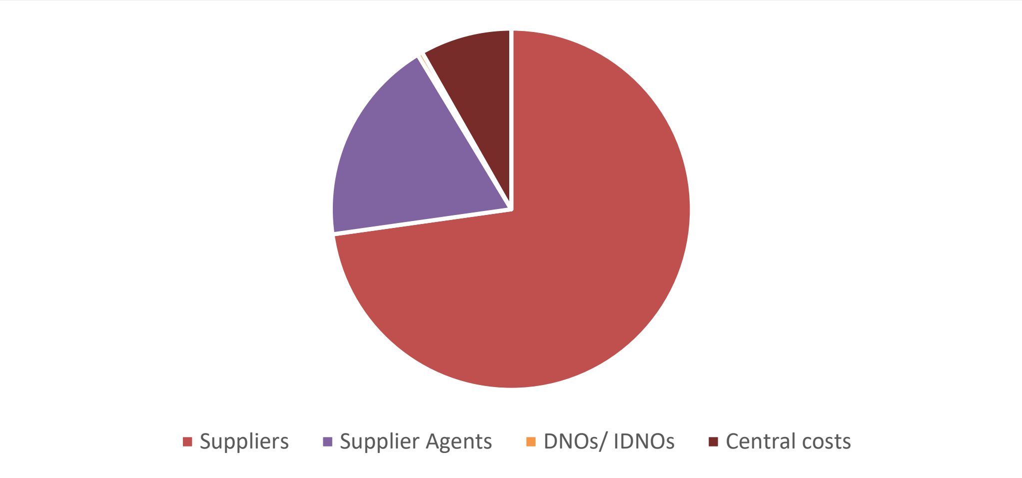
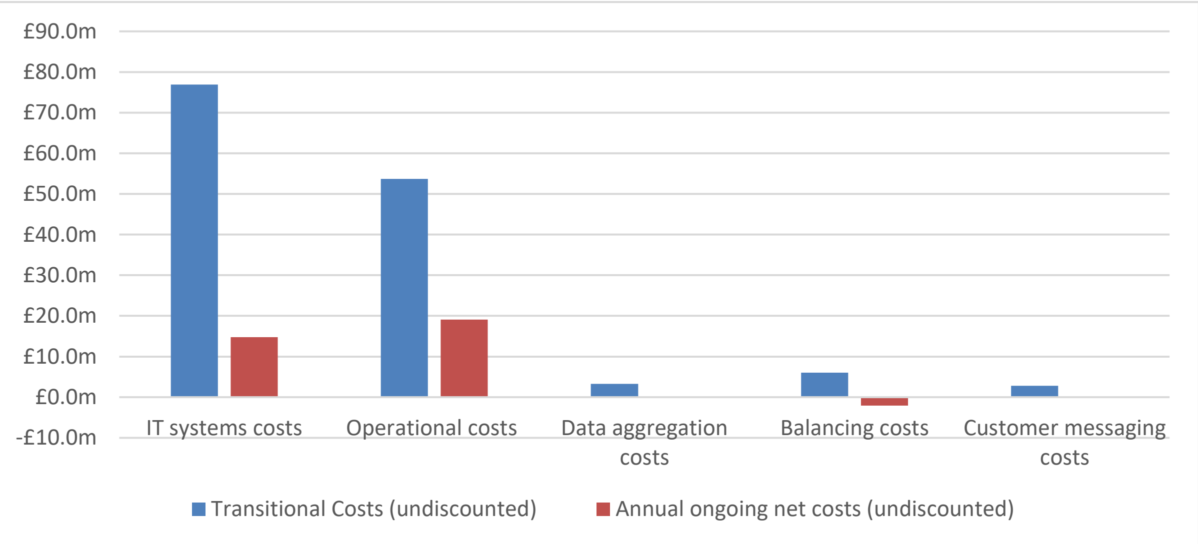


Table 5: Estimated net direct costs by cost type, option 2 (£ millions)

Costs of MHHS option 2	Transitional Costs (£2019, undiscounted)	Annual ongoing net costs (£2019, undiscounted)	Total net costs (2021-2045), 2018 NPV
IT systems costs	£76.9m	£14.8m	
Operational costs	£53.7m	£19.1m	
Data aggregation costs	£3.3m	£0.0m	
Balancing costs	£6.0m	-£2.1m	
Customer messaging costs	£2.8m	£0.0m	
Total costs	**£142.7m**	**£31.8m**	**£492.5m**

Figure 4: Estimated net direct costs (undiscounted) by cost type, option 2



Cost ranges

3.88. As noted at the beginning of this section, we asked stakeholders to qualify their quantitative responses to the RfI using a +/- uncertainty margin. We have used this information to build a cost range. We consider the central cost to be our best estimate of costs. The cost range shows the level of uncertainty industry faces when trying to cost accurately the changes required for MHHS.

3.89. Table 6 below summarises the range of costs we have developed. We have used this range to develop the potential net impacts for consumers shown in section 6.

Table 6: Estimated net direct cost ranges, cost uncertainty (£ millions)

Uncertainty range	Total transitional costs (£2019, undiscounted)	Total annual ongoing net costs (£2019, undiscounted)	Total net costs (2021-2045), 2018 NPV
High	£155.4m	£39.3m	£591.9m
Central	**£142.7m**	**£31.8m**	**£492.5m**
Low	£132.2m	£24.6m	£399.7m

3.90. We have excluded certain reported costs from these cost ranges on the basis that they do not appear reasonable to us. In particular, we do not propose to include the costs provided by suppliers of reading traditional meters every month. This is because, as noted earlier, we expect that the BSC PAF will take into account the extent of smart meter penetration and make appropriate adjustments to targets if necessary. On the other hand, we have included in our central estimate some costs of reading traditional meters every three months and we have included a 50% uncertainty for those costs in the high range. We believe this is a proportionate and conservative approach to these costs.

3.91. We have looked at the potential costs of offering new HHS products (such as Time of Use tariffs) in the market. For example, some suppliers have told us that they would need to update their billing systems to be ToU compatible. This investment is not required by options 2 and 3 and so we have not included it in our central estimate of costs or in the cost ranges shown in table 6 above.[27] However, we acknowledge that some of these costs might have to be incurred in order to realise the full potential of the estimated benefits.

3.92. Table 7 below shows the total estimated costs of offering HHS-enabled products and how those costs would increase the central cost estimate.

Table 7: Estimated net direct costs of offering HHS products (£ millions)

	Total one-off costs (undiscounted)	Total ongoing net costs (undiscounted)	Total net costs (2021-2045), 2018 NPV
Central cost estimate	£142.7m	£31.8m	£492.5m
Extra costs of offering HHS products	£17.0m	£3.0m	£49.5m
Central cost estimate plus estimated additional costs of offering HHS products	**£159.7m**	**£34.8m**	**£542.0m**

Option 3 - MHHS for import MPANs only over a transition period of approximately 5 years

3.93. In this section, we summarise the evidence that we have received from all stakeholders about the costs of:

- including export-related MPANs, or not, within these reforms
- introducing MHHS for export-related MPANs at the same time as for import-related MPANs, and
- introducing MHHS over a shorter or longer timescale than the transition period of approximately 4 years that we have proposed in option 2.

3.94. Based on the evidence we have received, introducing MHHS only for import-related MPANs would reduce implementation costs relative to option 2. Export-related

[27] Some costs of offering ToU tariffs have been included.

transitional costs for suppliers and DNOs are estimated to total around £5.4m. DNOs would incur ongoing costs of about £50,000 associated with the increased volume of export registrations. Most of the costs stakeholders identified relate to registering and settling export MPANs rather than specifically settling them half-hourly. ELEXON confirmed that its systems can already accommodate export MPANs.

3.95. As noted above, the SEG should prompt many more suppliers to register export-related MPANs before any transition to MHHS is completed. This should enable a steady flow of registrations over the next few years and reduce the impact of having the same transition period for all MPANs. Bringing in MHHS for import and export MPANs at the same time could realise cost savings for suppliers. That said, we expect that some smaller suppliers currently have manual processes for dealing with export-related MPANs or do not serve export customers. We welcome further evidence about the costs of automating these processes.

3.96. Clearly, all these costs would be avoided if we pursued option 3. However, this should be set against the loss of the annual net ongoing cost savings that we expect to arise from including export MPANs within MHHS. We expect these cost savings to arise from improved network management, more accurate settlement and better forecasting for suppliers. Moreover, we expect a range of benefits that we cannot quantify arising from increased competition, innovation and consumer engagement due to the development of new and innovative tariffs in this sector of the market (see sections 4 and 5).

3.97. Most RfI respondents said costs would be similar with a 4- or 5-year transition. Some suppliers, and one supplier agent, said a 3-year transition could increase costs as a result of having to procure additional resources to handle the extra work during 2020 and 2021. Without these extra resources, we were told a rapid transition period could affect the design quality and overall robustness of the new settlement arrangements.

3.98. In the table below, we present an estimate of the total costs (in NPV terms) under option 3. To calculate these costs, we have assumed no cost increase or reduction due to the longer implementation period, and divided transitional costs equally across the transitional period for that option of approximately 5 years (2021-2025) (except for programme cost for which we have estimated an increase in transitional costs under option 3). Ongoing costs are accounted for over the period 2026-2045.

Table 8: Estimated net direct costs of option 3 by cost type (£ millions)

Costs of MHHS option 3	Transitional costs (£2019, undiscounted)	Annual ongoing net costs (£2019, undiscounted)	Total net costs (2021-2045), 2018 NPV
IT systems costs	£76.9m	£14.8m	
Operational costs	£53.7m	£19.2m	
Data aggregation costs	£3.3m	£0.0m	
Balancing costs	£6.0m	-£2.1m	
Customer messaging costs	£2.8m	£0.0m	
Total costs	**£142.7m**	**£31.9m**	**£467.7m**

3.99. The table below shows the difference in total costs between options 2 and 3.

3.100. We estimate that the total costs of option 3 in 2018 NPV terms are about £24m lower than option 2 over the period 2021-2045. This is for two reasons. First, the longer transition period under option 3 means the ongoing costs (new BAU) start to be realised one year later. Second, we are looking at the costs over the same period in both MHHS options (2021-2045), so ongoing costs under option 3 are accounted for a shorter period (2026-2045 instead of 2025-2045).

Table 9: Estimated net direct cost comparison of options 2 and 3 (£ millions)

Costs MHHS – comparison	Transitional costs (£2019, undiscounted)	Annual ongoing net costs (£2019, undiscounted)	Total net costs (2021-2045), 2018 NPV
Option 2	£142.7m	£31.8m	£492.5m
Option 3	£142.7m	£31.9m	£467.m
Cost difference	**£0.1m**	**£0.2m**	**-£24.0m**

4. Monetised direct benefits

Section summary

This section sets out our estimation of the monetised direct benefits of market-wide half-hourly settlement (**MHHS**). We have used a GB power market model - the Dynamic Dispatch Model (**DDM**)[28] - to calculate these benefits.

We begin by outlining the range of benefits that we have sought to quantify. We explain the methodology and assumptions behind our analysis and describe the load shifting and fossil fuel price scenarios that we have considered. We then discuss the interactions between MHHS and the Targeted Charging Review (**TCR**) and the Access and Forward Looking Charging Reform and set out our approach to calculating and attributing benefits across these closely related projects.

We then set out the results of our DDM analysis, which estimates very significant benefits from MHHS. We include an estimate of potential carbon emissions savings. We have also used BEIS' Distribution Networks Model (**DNM**) as a sensitivity analysis to capture potential benefits at the distribution network level.

Finally, using evidence from our Request for Information, we sought as far as possible to quantify the direct benefits of better demand forecasting and a more efficient settlement process. Other significant benefits such as the effect on competition, innovation and customer outcomes cannot be quantified and/or attributed solely to MHHS. They are covered in section 5 on unquantified benefits.

Benefits covered in this section

4.1. In this section we estimate the direct quantifiable benefits of MHHS. This includes the benefits from different levels of load shifting by domestic and small non-

[28] The DDM and the Distribution Networks Model (**DNM**) are described in Appendix 1.

domestic consumers[29] under certain scenarios. This analysis seeks to capture benefits such as:

- generation and network investment savings through better use of existing assets (note the model we used does not fully capture all the potential benefits: see the subsection below on the DDM's limitations in relation to network costs)
- operational savings as load shifting reduces the need to operate generation assets at peak times
- the carbon emissions saved because the lower demand can be satisfied with less polluting generators
- the benefits from more accurate forecasting and matching of supply and demand, resulting in a reduction in the residual imbalance that the Electricity System Operator (**ESO**) needs to resolve, and therefore the costs of doing so
- a more accurate settlement process with better quality data and fewer errors, and
- a more efficient settlement process with shorter timeframes, reducing suppliers' exposure and the amount of collateral that suppliers must post to cover it.

Benefits from load shifting

4.2. A core objective of the energy transformation is to promote a decarbonised system by supporting the development and use of renewable generation and by lowering demand at peak times relative to what it would otherwise be, thereby minimising the need for infrastructure investment. MHHS is a critical enabler of this. We have sought to quantify the impact of a shift in consumption as a result of changes to the settlement arrangements using a GB power market model – the Dynamic Dispatch

[29] The scope of the project covers consumers in profile classes 1 to 4. However, the DDM has certain limitations on how it can distinguish between small non-domestic (classes 3 and 4) and other non-domestic (classes 5 to 8) demand. The model limitations are discussed in more detail below.

Model (**DDM**).[30] The following paragraphs explain the methodology and assumptions that underpin our use of this model.

Modelling methodology

4.3. The DDM analyses electricity dispatch decisions from GB power generators and investment decisions in generating capacity from 2010 to 2050. It can show the impact of policy decisions on generation, capacity, costs, prices, security of supply and carbon emissions.

4.4. The DDM has been used for a number of key policy decisions such as the 2019 updated smart meter rollout cost-benefit analysis and the Hinkley Point C value for money assessment. The DDM has been used for this analysis on the basis of a set of assumptions determined by Ofgem, in a number of different scenarios. We describe these below.

Scenarios and sensitivities

4.5. Predicting electricity system outcomes, such as the potential level of load shifting facilitated by MHHS, is extremely challenging because of the uncertainty about technological, market and behavioural factors that influence those outcomes. Given the high level of uncertainty, we have taken the following scenario-based approach:

- **Load shifting scenarios**: these scenarios identify a range of possible load-shifting outcomes under each of the policy options, by specifying a likely upper and lower bound to the possible load shifting outcomes (discussed in the subsection below on modelling assumptions)

- **Electricity system scenarios**: these identify different potential pathways for the future development of the electricity system. We have used two such scenarios:

  - a Central fossil fuel (**CFF**) price scenario which is consistent with BEIS' annually updated Reference Case scenario (2018 figures). This is the main projection in

[30] More information on the DDM can be found here and in Appendix 1.

BEIS' Energy and Emissions Projections.[31] It is based on central projections for the key drivers of energy emissions, such as fossil fuel prices, GDP and population. This is our base case

- a low fossil fuel (**LFF**) price scenario, in which less value is associated with flexible demand, which we expect to be indicative of the likely lower bound for overall expected system benefits of load shifting. We regard this scenario as unlikely given the importance of electricity system flexibility in helping the UK meet its Net Zero commitments. We therefore present it in this IA as a sensitivity analysis only.

4.6. We have tested the following additional sensitivities:

- reducing the load shifting window, this shows the change in the modelled benefits when the restrictions on how the demand is shifted away from the peak and across the day are changed (as discussed in paragraphs 4.43-4.45)
- the benefits of load shifting on the distribution networks using the DNM, which is discussed in a subsection below on modelling distribution network level benefits, and
- a high carbon value scenario showing how the impacts (cost savings from reduction in carbon emissions) would change under a scenario where carbon emissions have a higher cost. This is discussed in a subsection below on carbon emissions.

4.7. Table 10 below summarises the scenarios used in the analysis.

[31] See Department of Business, Energy and Industrial Strategy, 'Updated energy and emissions projections: 2018'.

Table 10: Scenarios used in the DDM modelling

Electricity system scenarios	Load shifting scenarios	Scenarios	Sensitivity test
Central fossil fuel (CFF) prices	Low load shifting	Scenario 1	Reducing the load shifting window
			Including distribution networks benefits
			High carbon cost
	High load shifting	Scenario 2	Reducing the load shifting window
			Including distribution networks benefits
			High carbon cost
Low fossil fuel (LFF) prices	Low load shifting	Sensitivity analysis only	LFF – Low load shifting
	High load shifting	Sensitivity analysis only	LFF – High load shifting

Model inputs

4.8. The DDM takes economic, climate, policy, generation and demand variables as external inputs. BEIS defines these inputs in its baseline modelling scenarios. This includes the fossil fuel prices used in the CFF and LFF price scenarios. In our modelling we used the fossil fuel price estimates from the Government's 2018 "Energy and Emissions Projections".[32]

4.9. In our modelling, the factual (option 2) and the counterfactual (status quo, option 1) in each scenario were distinguished by the fact that they took different values for the load-shifting constraint: the maximum proportion of demand that can be shifted from any half hour of the day to another. We explain the effect of our load shifting assumptions on the DDM below, and in Appendix 2.

[32] Link to Department of Business, Energy and Industrial Strategy, 'Updated energy and emissions projections: 2018' (April 2019).

Model outputs

4.10. The outputs from the DDM include the changes in expected net welfare, consumer surplus and producer surplus resulting from the policy, as well as carbon costs. These outputs are constituted as follows:

- change in net welfare is the sum of changes in carbon costs, generation costs, capital costs, system costs, unserved energy, interconnectors, and unpriced carbon[33]
- change in consumer surplus is the sum of changes in the wholesale price, low carbon payments, capacity payments, and unserved energy, and
- change in producer surplus is the sum of changes in the wholesale price, low carbon price support, capacity payments, and producer costs.

4.11. The model also calculates changes in environmental tax revenue between the factual and the counterfactual.

4.12. Generation costs and capital costs together encapsulate the variable, operating and construction costs of generation. System costs are transmission network costs, consisting of Transmission Network Use of System, Balancing Services Use of System and inertia costs. Distribution network costs are not included in the DDM's outputs, so we have used BEIS' Distribution Networks Model as a sensitivity to capture these potential benefits. Those results are set out in the subsection below on modelling distribution network level benefits.

Modelling assumptions

4.13. The modelling period we chose for the analysis was from 2025 to 2045. This reflects the long-term nature of the chain of benefits. We specified the load shifting

[33] Change in net welfare can also be expressed as the sum of the change in consumer surplus, producer surplus, environmental tax, unpriced carbon (societal benefit) and GB interconnector surplus.

constraint as a 'straight line' progression from the value at 2025 to a maximum value during the modelled time period up to 2045.

4.14. There is significant uncertainty about how much demand will be shiftable in the future. Among other things, this depends on the tariffs offered by suppliers, the availability of technologies for shifting load automatically, price signals, and consumers' response to price signals. Instead of estimating each of these variables to inform an estimate of potential load shifting, we have estimated a range of values for load shifting from a review of research and trials that look at load shifting in response to price signals. We looked at two key parameters for determining the extent of load shifting:

- the take-up of smart tariffs and
- the level of load shifting by customers on smart tariffs, as a percentage of peak reduction.

4.15. The overall level of load shifting away from the system peak can be calculated as the product of these two parameters:

System load shifting = proportion of customers with a smart tariff × percent of demand shifted at peak by customers with a smart tariff

4.16. Drawing upon existing academic literature, we identified a range of estimates for each parameter. Combining both parameters, we estimated a range for potential load shifting. Table 24 in Appendix 2 shows the value of each parameter.

4.17. The load shifting constraints for domestic and non-domestic demand, including Electric Vehicle (**EV**) and heat pump demand, are specified separately in the model. We assigned a higher value to the load shifting constraint for domestic EVs than for other demand, reflecting the greater ability for EV demand to shift.[34] We assigned the same level of load shifting constraint for domestic and non-domestic heat pump demand in the counterfactual and the factual (option 2), which means that the DDM

[34] As noted above, Appendix 2 provides more detail on the load shifting parameters.

results capture no benefits from increased heat pump flexibility. Assuming that MHHS will not increase load shifting from heat pumps is a conservative approach.

4.18. Table 11 below shows the final level of load shifting in each load shifting scenario. This is shown as an increase on the baseline load shifting level in the counterfactual. Tables 12 and 13 respectively show the load shifting attributable to MHHS and the baseline in the counterfactual.

Table 11: Load shifting assumptions (% of peak load), low and high load shifting scenarios

Assumptions	Load shifting scenarios	Year	Domestic demand, non-domestic EV demand	Domestic EV demand	Domestic/non-domestic heat pump demand[35]
% of total demand during peak hours that can be shifted	Low load shifting	2025	1%	2%	90%
		2045	6%	14%	90%
	High load shifting	2025	6%	7%	90%
		2045	30%	38%	90%

Table 12: Load shifting increase under MHHS relative to the counterfactual

Assumptions	Load shifting scenarios	Year	Domestic demand, non-domestic EV demand	Domestic EV demand	Domestic/non-domestic heat pump demand
% of total demand during peak hours that can be shifted	Low load shifting	2025	1%	1%	0%
		2045	6%	6%	0%
	High load shifting	2025	6%	6%	0%
		2045	30%	30%	0%

[35] The same level of load shifting was assumed in the factual and in the counterfactual. Load from heat pumps was only allowed to shift by one hour (one-hour shifting window).

Table 13: Load shifting (% of peak load) in the counterfactual

Assumptions	Load shifting scenario	Year	Domestic demand, non-domestic EV demand	Domestic EV demand[36]	Domestic/non-domestic heat pump demand[37]
% of total demand during peak hours that can be shifted	Counterfactual	2025	0%	1%	90%
		2045	0%	8%	90%

4.19. We have assumed an 8-hour window in which demand in any half-hour is allowed to shift (either up to 4 hours earlier or up to 4 hours later). We believe that this is a good approximation of small users' ability to offer flexibility across different technologies. We have tested the implications of this assumption through two sensitivity tests that restrict the shifting window to 4 hours and 2 hours.

4.20. As a result of stakeholder feedback, we have refined the assumptions that we used for the MHHS Outline Business Case (**OBC**). In particular, we have worked with BEIS to avoid capturing benefits from big non-domestic consumers and we have slightly reduced the load shifting assumptions in the high load shifting scenario. We have also included demand from EVs in the main analysis[38] and a new set of load shifting assumptions for EV demand.

4.21. We believe the modelling analysis is more robust as a result of these changes. That said, the DDM has certain limitations that are important to recognise. In particular, the DDM:

- accounts for network cost savings at the transmission level only, so omits distribution networks cost savings. Furthermore, it does not fully capture the benefits that

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[36] The level of load shifting constraint for domestic EVs we have used in the counterfactual differs from BEIS's assumption in 2018 "Energy and Emissions Projections".
[37] The same level of load shifting was assumed in the factual and in the counterfactual. Load from heat pumps was only allowed to shift by one hour (one-hour shifting window).
[38] In the OBC we included EV demand in the sensitivity analysis only. However, we thought this was significantly underestimating the project benefits.

load shifting could have for the transmission network. Notably, the model does not represent cost associated with reinforcing and maintaining the network in relation to load shifting, and location of new generation is not optimised to reduce MW-km costs. We have used the DNM to estimate the benefits from distribution networks cost savings and the results are shown as part of the sensitivity analysis below

- can either allow both **domestic** and **non-domestic** load to shift, or only domestic load. However, the DDM does not distinguish within these categories and does not separate smaller non-domestic consumers (Profile Classes 3-4) from other sources of non-domestic load, such as non-domestic consumers covered by P272 (formerly Profile Classes 5-8) and 'traditional' half-hourly sites in Measurement Class C.[39] The scope of our project includes Profile Classes (**PC**) 1-4. To estimate the effects of load shifting by customers as a result of MHHS, we applied our load shifting assumptions to domestic demand and to a proportion[40] of non-domestic demand corresponding to PCs 3-4

- can also allow EV demand to shift separately from domestic and non-domestic demand. Based on our review of the evidence, we expect that there would be some EV demand shifting under elective HHS. This is reflected in our assumptions for the counterfactual. We assumed that the potential EV demand load shifting in the scenarios is equal to the sum of potential EV demand load shifting under the counterfactual and potential domestic demand load shifting in the relevant scenario.

4.22. The output from the DDM model does not account for any costs to consumers of load shifting. These could be costs to purchase technological enablers such as smart appliances or batteries, or costs in understanding and responding to price signals in tariffs. Some of these costs could be mitigated to an extent if suppliers can offer new products and innovations that are simple for consumers to understand and engage with.

4.23. The figures from the modelling set out an indicative range of potential benefits, rather than specific estimates, in order to highlight the magnitude of potential

[39] GB metering systems are categorised by seven Measurement Classes. See ELEXON, 'Change of Measurement Class and Change of Profile Class' (June 2019).
[40] Consistent with Smart meter roll-out: cost-benefit analysis (2019) assumptions.

benefits that can be achieved. These figures are supplemented in our qualitative assessment of the impacts of MHHS on competition and innovation in the market.

Interaction of MHHS with other policies

4.24. MHHS is an important part of Ofgem's Decarbonisation Action Plan.[41] It is one of several Ofgem policies that is intended to promote electricity system flexibility. Like those other policies, MHHS will do this by sending cost-reflective signals to market participants about the cost of serving their customers throughout each day. This will place incentives on suppliers to offer new tariffs and products that encourage more flexible use of energy, potentially minimising inefficient investment in the energy system. MHHS will facilitate other policies by making it possible for suppliers to be charged based on the time period in which the energy was consumed.

4.25. MHHS interacts particularly closely with the Targeted Charging Review and the Electricity network access and forward-looking charging Significant Code Review. Given the close interactions, it is important to ensure as far as possible that the basis of the estimated benefits is clearly set out so that an informed assessment is made as to the anticipated impact of each project. See paragraphs 4.29-4.34 for our approach to this in relation to Access and forward-looking charging reform. Given the interactions between the projects and differences in the focus of their policy options and assessment, we would not recommend simply summing their estimated impacts in order to estimate their aggregate effects.

Targeted Charging Review

4.26. The TCR reforms will introduce a series of fixed residual charges to address inefficient price signals which create harmful distortions in the market. This new charge structure will mean there is no variability in a customer's residual network charges throughout the day.

[41] Chapter 2 of the consultation document sets out the strategic context for settlement reform and summarises key elements of our Decarbonisation Action Plan.

4.27. Some stakeholders have expressed the view that the TCR, by eliminating some time-based price signals, has reduced the benefits available from MHHS. Our view is that the signals removed by TCR were distortive and that the reforms will enable other markets to send more efficient signals. For example, we expect the TCR to lead to an increase in wholesale market prices during peak periods.

4.28. The benefits case for MHHS needs to be considered in the light of other policy developments taking place on the timescale of MHHS implementation as well – including Access and forward-looking charging reform (see below). These policies, along with the variation in wholesale costs and any other determinants of price variation, will have an impact on where on the scale, from the low load shifting to the high load shifting scenario the benefits will fall.

Access and forward-looking charging reform

4.29. In our Access and forward-looking charging reform project we are reviewing forward-looking network charges, with the aim of ensuring that electricity networks are used efficiently and flexibly, reflecting users' needs and allowing consumers to benefit from new technologies and services while avoiding unnecessary costs on energy bills in general.

4.30. A number of the reform options under consideration will build on MHHS, so some of the potential benefits of these reforms are dependent on the implementation of MHHS. Access and forward-looking charging reforms could therefore contribute to the potential benefits which MHHS will enable. Any improvements to forward-looking charging arrangements introduced under Access and forward-looking charging reform would reduce system costs by encouraging network users to change their behaviour. This MHHS impact assessment (**IA**) includes some benefits from consumption shifting and reducing network cost.

4.31. Given the complexity of the interactions between MHHS and Access and forward-looking charging reform, it is challenging to separate fully the benefits arising from each of these policies. As such, our decisions on each programme of work will (to the extent practicable) consider the respective contributions that each policy is expected to bring to realising the anticipated benefits.

4.32. As explained above, the modelling of the benefits from MHHS considered a range of load shifting values. We recognise that in order to realise the benefits toward the upper end (or above) of the range of estimated benefits, new reforms that increase time-based price signals in the market (eg. some of the options considered under Access and forward-looking charging reform) are likely to be needed. We therefore consider that, when distinguishing the benefits of MHHS itself from those of other programmes enabled by MHHS, the conservative approach is to look at the low end of our modelled range. Some of the proposed access and forward-looking charging reforms could increase the benefits more towards the high estimate of the range, or potentially beyond.

4.33. As noted above, the DDM does not include distribution network-specific benefits. We have therefore also modelled the distribution network effects of MHHS. Our analysis suggests that increasing levels of load shifting would benefit the distribution network (see the subsection on modelling distribution network level benefits). However, given the interactions with the Access and forward-looking charging reform, we consider distribution level benefits as part of our sensitivity analysis rather than as part of our central benefits case, in order to reduce the risk of double counting. In addition, the DDM is limited in its inclusion of transmission network-specific benefits, which reduces the potential for overlap with Access and forward-looking charging reform benefits.

4.34. Access and forward-looking charging reform may also result in benefits from areas beyond the scope of those enabled by MHHS. Some of the options under Access and forward-looking charging reform may directly affect the economic incentives on generators or incentivise load shifting for larger demand customers, bringing about benefits that are not counted in the MHHS IA.[42]

System-wide benefits from load shifting under option 2

4.35. The output from the DDM modelling is set out in tables 14-15 (in £ millions rounded to the nearest £50 million). These results are presented in Net Present Value (**NPV**) terms, discounted with 2018 as the base year and using 2018 real prices. We have used the Green Book discount rate to calculate NPVs. This discount rate is set at

[42] The MHHS IA only considers load shifting impacts for customers in profile classes 1-4. While the modelling for MHHS takes into account indirect effects on generators' incentives arising from different consumption patterns, it will not introduce policies that affect commercial generators directly.

3.5% (in real terms) for the entire period of the analysis (2025-2045) in line with the Green Book guidance.[43]

4.36. The outputs are presented as net welfare, which consist of carbon cost savings, generation, capital and network cost savings, balancing cost savings, unserved energy, interconnectors and unpriced carbon. Net welfare can be broken down into:

- Consumer surplus – consisting of wholesale price reductions, low carbon and capacity payments, network costs, balancing costs and unserved energy
- Producer surplus – consisting of wholesale price reductions, low carbon and capacity payments and producer costs
- Environmental tax
- Societal benefit – consisting of unpriced carbon (the difference between low carbon payments and the carbon appraisal value), and
- GB Interconnector surplus.

4.37. Some benefits to one group directly transfer into costs against another group, generating net zero benefits/costs. For example, capacity payments are a cost (negative) to consumers but a benefit (positive) of exactly the same amount for producers. Other outputs generate additional benefits/costs.

4.38. The outputs show a **net welfare increase under both scenarios**, with a net system benefit that increases over time. This increase is driven mainly by benefits from generation costs savings in the high load shift scenario, capital[44] cost savings in the low load shift scenario, and interconnector flow savings in both scenarios.[45]

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[43] See 'The Green Book: Central Government Guidance on Appraisal and Evaluation.'
[44] The DDM does not account for distribution network costs or cost savings, which would be additional to the figures presented in this analysis.
[45] Interconnector cost savings are explained by the fact that net imports decrease as the demand peaks are reduced, meaning less electricity is imported as demand can be met through cheaper domestic generation. Note that interconnectors that have been awarded a cap and floor regime have all been assessed through an Initial Project Assessment (**IPA**) and are considered to be likely in the interests of GB consumers (see here and here).

4.39. These interconnector cost savings make up a higher proportion of the net welfare increase under the high load shift scenario. They outweigh an increase in transmission network costs. These costs increase because the increase in load shifting leads to a higher proportion of transmission-connected renewables in the capacity mix. In particular, the capacity of offshore wind increases, which has associated a higher network cost than other generation sources. The DDM also shows a decrease in the capacity of distribution connected storage, but this does not affect the network savings outputs as distribution network costs are not estimated in the DDM (however, it impacts the analysis in the DNM as less storage will be connected to the representative networks in the model).

4.40. We ran the DNM as a sensitivity analysis to investigate the effects of increased load shifting on distribution network costs. The distribution cost savings estimated by the DNM outweigh the transmission network cost increase estimated by the DDM. Carbon cost savings make a significant contribution in all scenarios, as better use is made of existing generation and new build plant has a lower carbon intensity.

4.41. There is a significant welfare transfer[46] from producers to consumers. This transfer is greater under the high load shifting scenarios than under the low ones. This comes from a reduction in wholesale prices during peak periods. Load shifting reduces peak demand, so the wholesale market clears at a lower price. Consumers therefore pay less for the energy purchased in those periods and producers receive less money for the energy they generate.

4.42. Under all scenarios, the results indicate potentially significant system-wide benefits from introducing MHHS.[47] The results also highlight the scale of the benefits that could be achieved by implementing policies that encourage flexibility across the electricity system. The potential net welfare benefits under the base case across the two scenarios range from £1.2bn to £3.6bn NPV by 2045 (in 2018 prices).[48] The wide range reflects the significant uncertainties about the energy system transition

[46] A welfare transfer does not generate additional benefits or costs, but redistributes benefits or costs from one group to another (producers to consumers or vice versa).
[47] As discussed at the beginning of chapter 4, this analysis takes account of different costs such as carbon costs, electricity generation costs or capital cost of new electricity generation assets, but not the costs discussed in chapter 3.
[48] As stated above, these net welfare results are smaller than what we estimated for the OBC (2018 NPV £1.8bn - £5.4bn), reflecting our refinement of the model and load shifting parameters.

and the range of outcomes that are therefore possible. The results are presented in NPV terms and rounded to the nearest £50 million.[49]

Table 14: Modelling output (benefits) - Scenario 1: low load shifting scenario, Central Fossil Fuel (CFF) prices, £ millions, difference compared to the counterfactual (option 1)

Cumulative, in £ millions, 2018 NPV	Scenario 1: low load shifting, CFF prices		
Year	**2030**	**2040**	**2045**
Net welfare			
Change in net welfare	**200**	**750**	**1,200**
Carbon costs	*	50	100
Generation costs	*	*	-150
Capital costs	100	400	450
Network costs	*	50	50
Balancing costs	*	-50	-50
Unserved energy	50	50	50
Interconnectors costs	*	300	750
Unpriced carbon (appraisal value)	*	*	*
Distributional analysis			
Change in consumer surplus	450	1,550	2,100
Change in producer (generator) surplus	-200	-600	-450
Change in Environmental Tax Revenue	*	*	*
Change in Unpriced Carbon	*	*	*
Change in GB Interconnector surplus	-50	-200	-400

Note: due to rounding, some totals may not correspond with the sum of the separate figures.

[49] Figures below £50m are represented with "*".

Table 15: Modelling output (benefits) - scenario 2: High load shifting scenario, Central Fossil Fuel (CFF) prices, (£ millions), difference compared to the counterfactual (option 1)

Cumulative, in £ millions, 2018 NPV	Scenario 2: high load shifting, CFF prices		
Year	**2030**	**2040**	**2045**
Net welfare			
Change in net welfare	**500**	**2000**	**3,600**
Carbon costs	100	500	1,000
Generation costs	550	750	500
Capital costs	100	-600	-950
Network costs	50	-550	-850
Balancing costs	*	-50	-150
Unserved energy	*	-50	-100
Interconnectors costs	-400	1,750	3,900
Unpriced carbon (appraisal value)	150	200	200
Distributional analysis			
Change in consumer surplus	350	2,650	5,050
Change in producer (generator) surplus	150	-350	-600
Change in Environmental Tax Revenue	*	*	*
Change in Unpriced Carbon	150	200	200
Change in GB Interconnector surplus	-100	-550	-1,050

Note: due to rounding, some totals may not correspond with the sum of the separate figures.

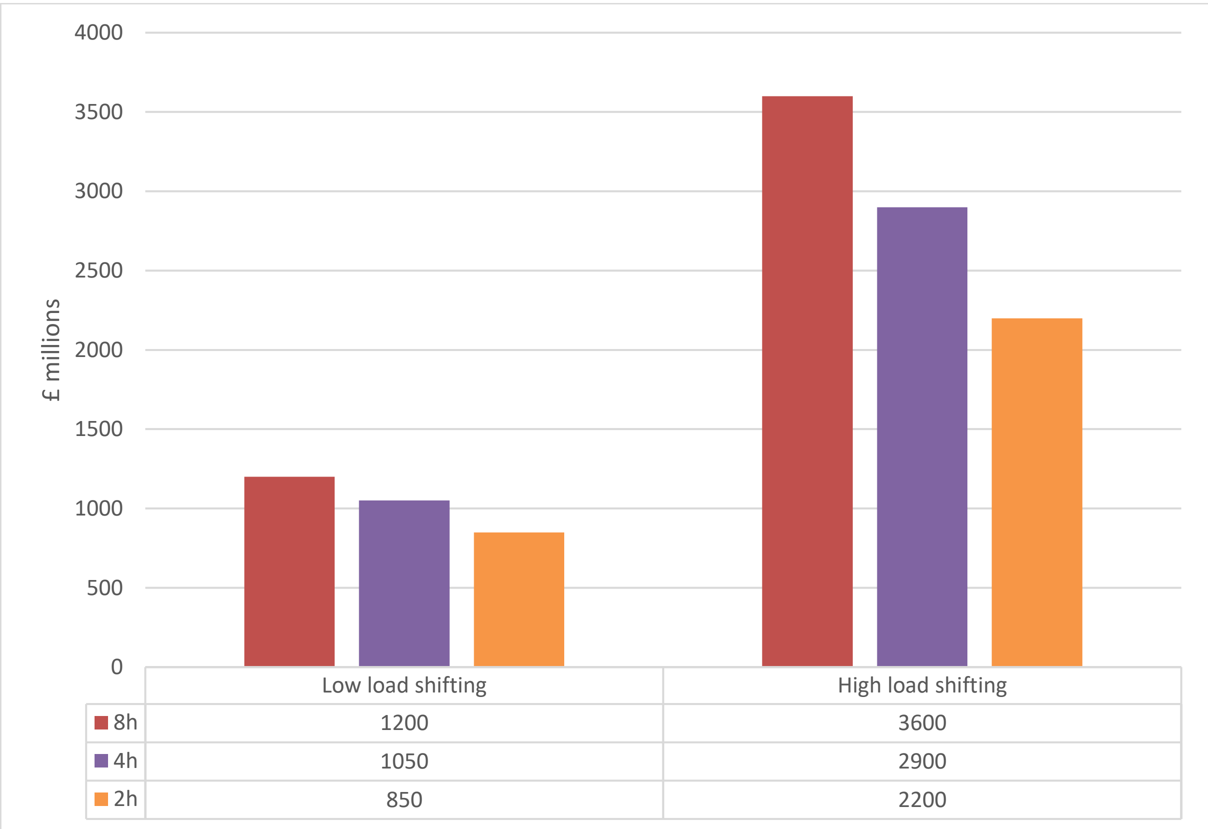
4.43. We tested two additional sensitivities across both scenarios:

- reducing the load shifting window from 8 hours to 4 hours
- reducing the load shifting window from 8 hours to 2 hours.

4.44. As expected, reducing the shifting window reduces net welfare benefits. This is true for both load shifting scenarios, with this effect becoming more pronounced with a smaller shifting window (though this effect varies across scenarios). Figure 5 shows the reduction in net welfare compared to the baseline (8-hour shifting window).

4.45. An 8-hour shifting window, assuming an allowed shift of 4 hours each side of peak periods, aligns with several load shifting possibilities, such as shifting washing machine and dishwasher load, overnight charging or using domestic battery storage. While an 8-hour window therefore seems realistic, moving this to a 4-hour (2 hours either side of peak) or 2-hour (1 hour either side of peak) window allows us to consider how the benefits could change. We will examine the available evidence on this and use this to inform our understanding of the uncertainty associated with our modelling results.

Figure 5: Sensitivities – reducing the shifting window, cumulative benefits from 2025 to 2045, 2018 NPV figures (8-hour window is the base case), £ millions

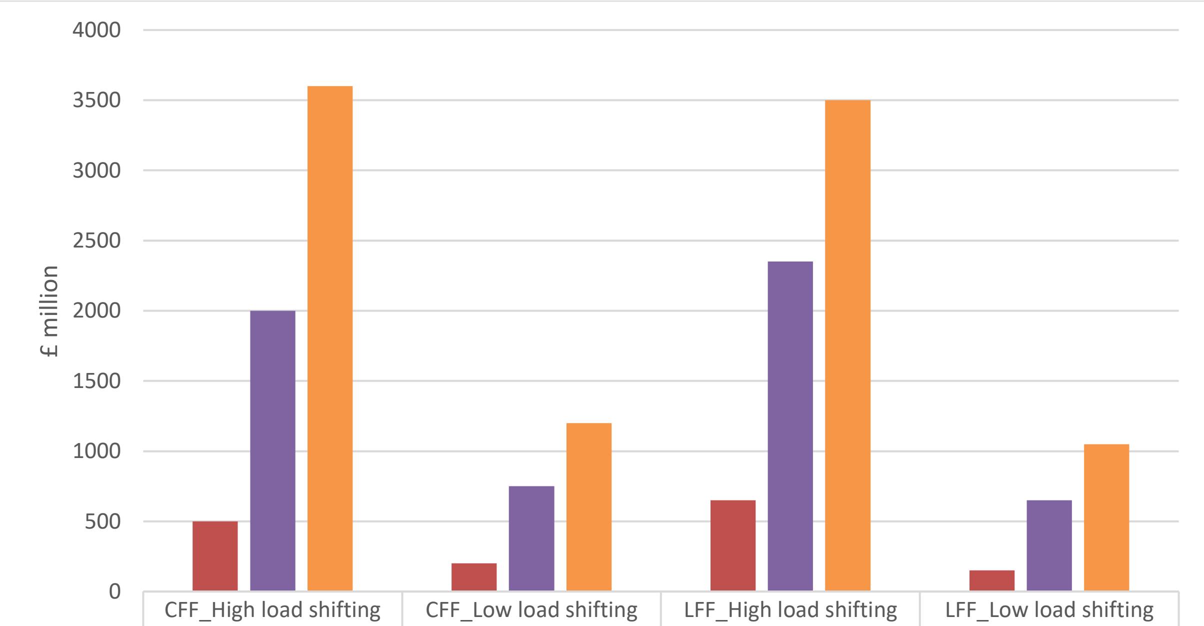


Electricity system scenarios - sensitivity analysis

4.46. We have tested the sensitivity of the assessment to future fossil fuel prices using BEIS' LFF price scenario, in which less value is associated with flexible demand. We expect this to be indicative of the likely lower bound for overall expected system benefits of load shifting. We regard this scenario as unlikely given the importance of electricity system flexibility in helping the UK meet its Net Zero commitments. We have, therefore, included it only as a sensitivity test in this draft IA.

4.47. Figure 6 shows the range of benefits across both the high and low load shifting scenarios for both CFF and LFF scenarios. As expected, the scenario with lower fossil fuel prices reduces the benefits we can expect from higher flexibility in the system. However, the sensitivity analysis also shows that the change in benefits associated with fossil fuel prices is relatively small, especially when compared to the variation across the low load shifting scenarios.

Figure 6: Sensitivities – benefits under CFF and LFF scenarios, 2018 NPV figures (CFF is the base case), £ millions



	CFF_High load shifting	CFF_Low load shifting	LFF_High load shifting	LFF_Low load shifting
2030	500	200	650	150
2040	2000	750	2350	650
2045	3600	1200	3500	1050

Modelling distribution network level benefits - sensitivity analysis

4.48. As noted above, the DDM does not capture distribution network cost savings. We have overcome this by using BEIS' DNM. However, we have decided to present the DNM results as a sensitivity analysis to reduce the risk of double counting these benefits with our Access and forward-looking charging reform.[50]

4.49. The DNM is a model of GB electricity distribution network costs from 2010 to 2050. It comprises two parts:

- a Power Flow Model (**PFM**) which uses representative networks to detect where the network becomes stressed and would be in need of reinforcement, and

- An Investment Model (**IM**), which chooses the most cost-effective solutions to resolve the issues identified by the PFM, replicating the process that a DNO would go through when assessing a network.

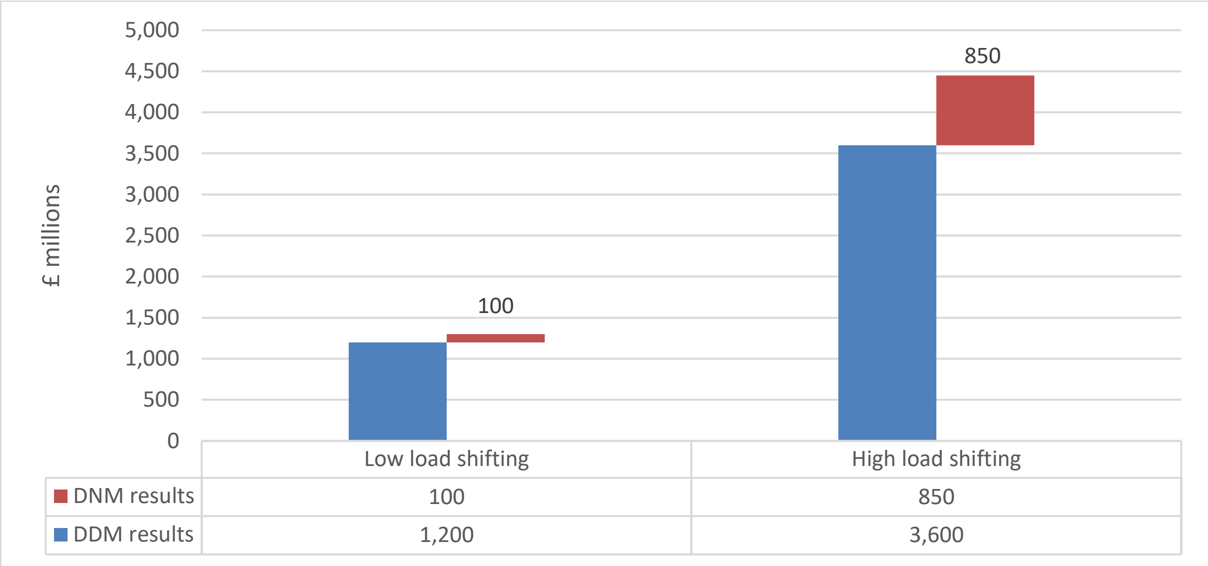
4.50. Alongside assumptions on representative networks and investment solutions, the DNM takes DDM outputs as inputs, including the level of demand shifted. Therefore, the same load shifting assumptions and considerations as for the DDM results apply here. We tested this sensitivity using two scenarios: low load shifting under Central Fuel Fossil prices, and high load shifting under Central Fossil Fuel prices.

4.51. The DNM output shows an increase in net welfare for both scenarios compared to the DDM results, increasing the total net welfare benefits from approximately £1.2billion - £3.6billion to £1.3billion - £4.4billion (2018 NPV) by 2045.

4.52. Figure 7 below illustrates these results.

[50] We discussed the interaction of MHHS with other Ofgem projects earlier in this chapter.

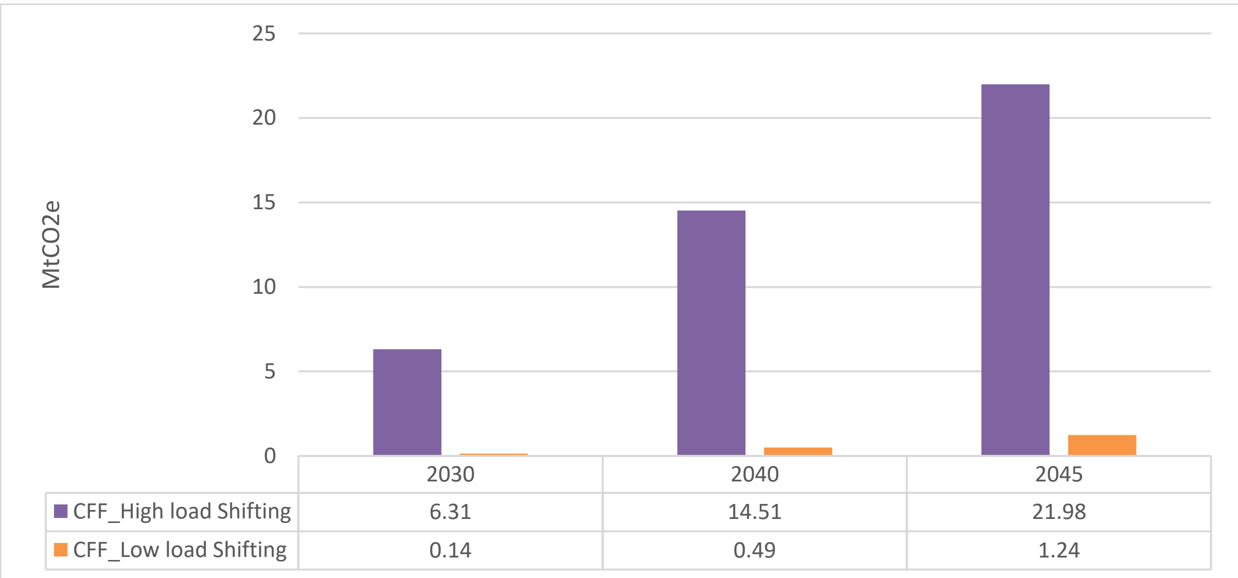
Figure 7: Sensitivities – including the DNM results, 2018 NPV figures cumulative benefits (2025-2045), central FFP, £ millions



Carbon emissions

4.53. We show the carbon emission savings calculated by the model. Figure 8 below shows the CO2 emissions (in MtCO2e) for the CFF scenario.

Figure 8: Estimated emissions savings (MtCO2e) under the Central Fossil Fuel (CFF) Prices high and low load shifting scenarios, cumulative figures



Carbon impacts

4.54. As noted earlier, the DDM can demonstrate the impact of policy decisions on carbon emissions. In particular, it produces two carbon emissions outputs that are included in the net welfare analysis:

- Carbon Costs: the total carbon emissions for a given year are multiplied by the expected European Emissions Allowance (**EUA**) price in that year

- Unpriced Carbon: this quantifies the difference between the actual EUA carbon price and the societal value of carbon (defined by the appraisal value). This is treated as a cost.

4.55. The DDM results show a reduction in carbon costs driven by a reduction in carbon emissions under all scenarios by 2045 (including the scenarios in the sensitivity tests). This reduction in carbon emissions is due to the higher proportion of renewables in the generation mix facilitated by the reduction in the peak consumption.

4.56. The table below shows the reduction in Carbon Costs and Unpriced Carbon costs under each scenario.

Table 16: Estimated carbon emissions savings (£ millions), 2018 NPV figures, cumulative

Cumulative in £ millions, 2018 NPV	All scenarios: total cost savings (carbon costs + unpriced carbon)		
Year	**2030**	**2040**	**2045**
High load shifting scenario - CFF	250	750	1,250
Low load shifting scenario - CFF	*	50	100

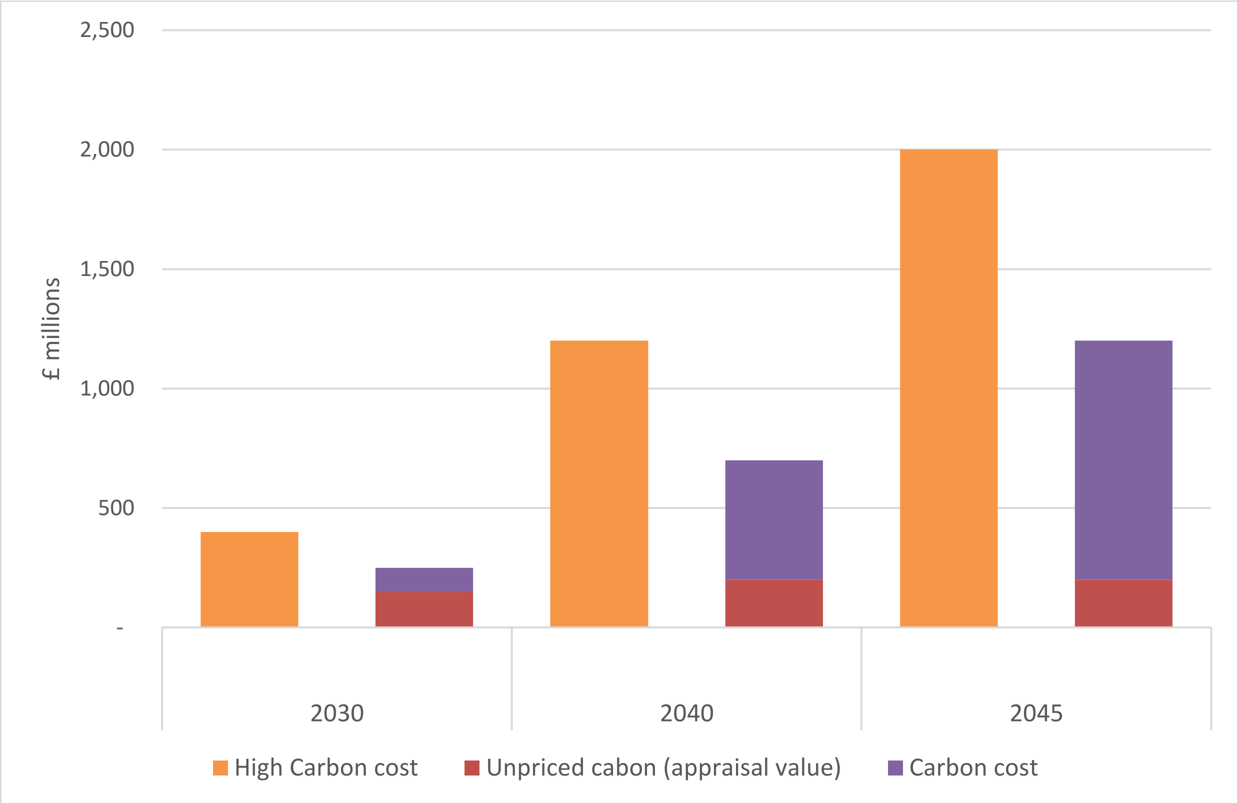
4.57. We have conducted a high carbon value[51] sensitivity analysis, showing how the impacts (cost savings from reduction in carbon emissions) would change under a

[51] Based on Department for Business, Energy and Industrial Strategy, UPDATED SHORT-TERM TRADED CARBON VALUES: Used for UK Public Policy Appraisal (January 2018).

scenario where carbon emissions have a higher cost. This is particularly relevant as the net zero commitment is likely to have implications for carbon values in future.

4.58. Figure 9 below shows how the cost savings from carbon emissions (in £ millions) increase under the high carbon value scenario compared to the base case.[52]

Figure 9: Estimated costs savings (£ millions) from reduction in carbon emissions, high load shifting, CFF price scenario, 2018 NPV figures, cumulative

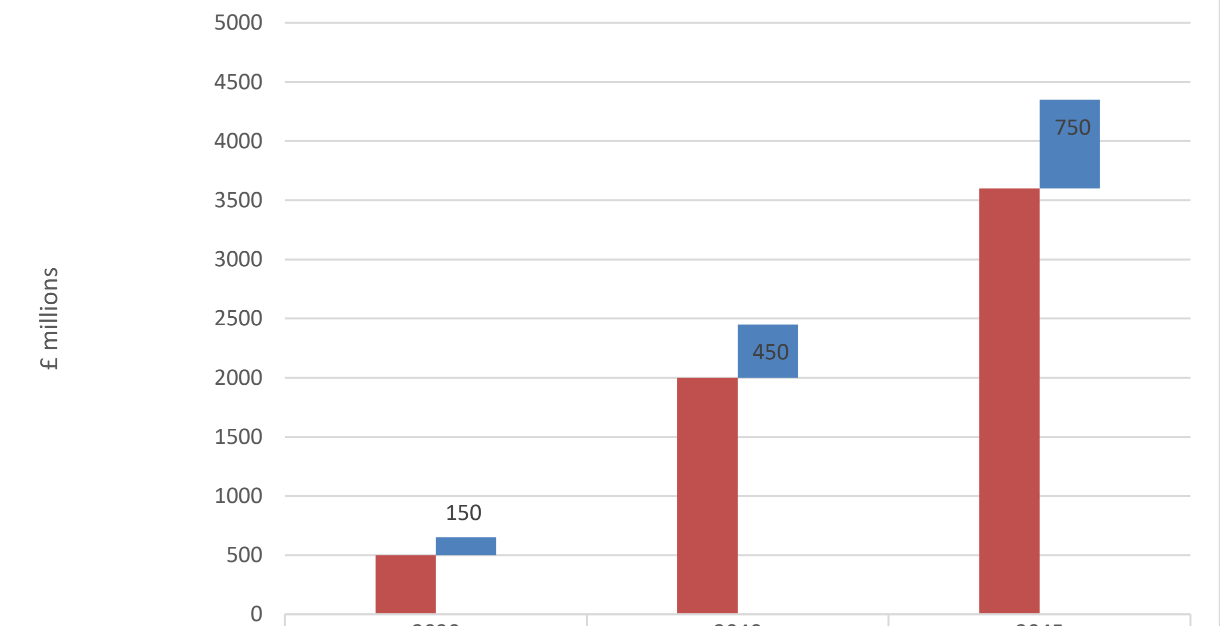


	2030	2040	2045
Carbon cost	100	500	1,000
Unpriced carbon (appraisal value)	150	200	200
High carbon cost	400	1,200	2,000

[52] As described in table 16, the total costs savings from carbon emissions in the base case are calculated as carbon costs and unpriced carbon.

4.59. Figure 10 below shows the increase in net welfare when using the high carbon value scenario compared to the base case. This figure also shows the difference between Carbon Costs and Unpriced Carbon Costs. It is worth noting that most of the carbon impacts in the base case are already captured by the Carbon Costs, and therefore Unpriced Carbon costs are relatively small.[53]

Figure 10: Estimated cost savings (£ millions) from reduction in carbon emissions, high load shifting, CFF price scenario, 2018 NPV figures, cumulative

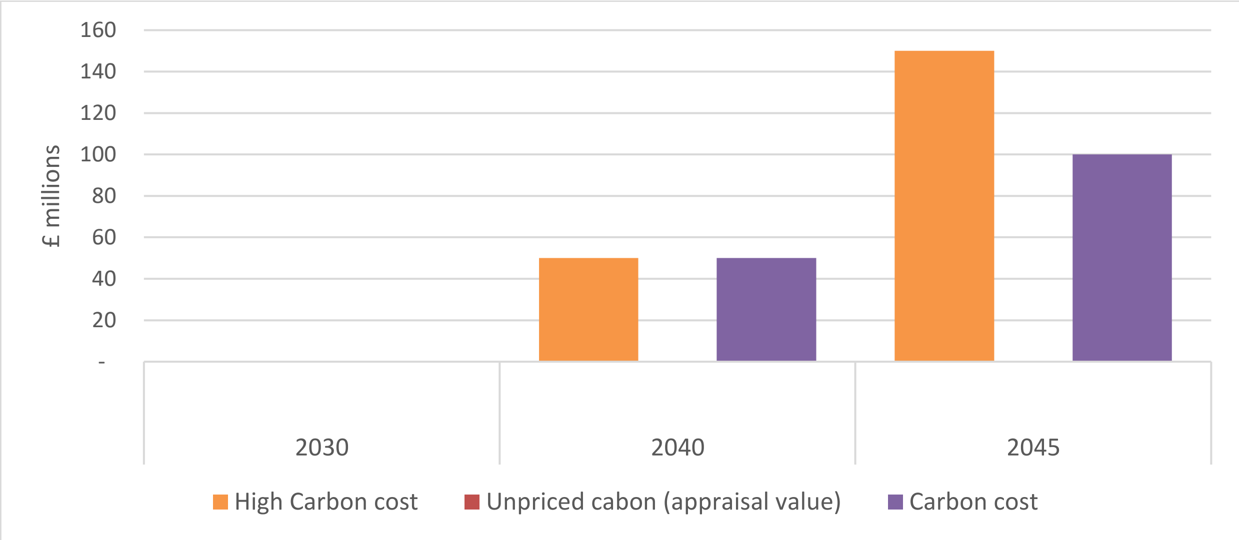


	2030	2040	2045
High carbon costs	150	450	750
Central Case benefits	500	2000	3600

4.60. Figures 11 and 12 describing the modelling outputs only show the Unpriced Carbon and Carbon Costs figures. Due to the rounding methodology, values below £50m are not shown in these figures.

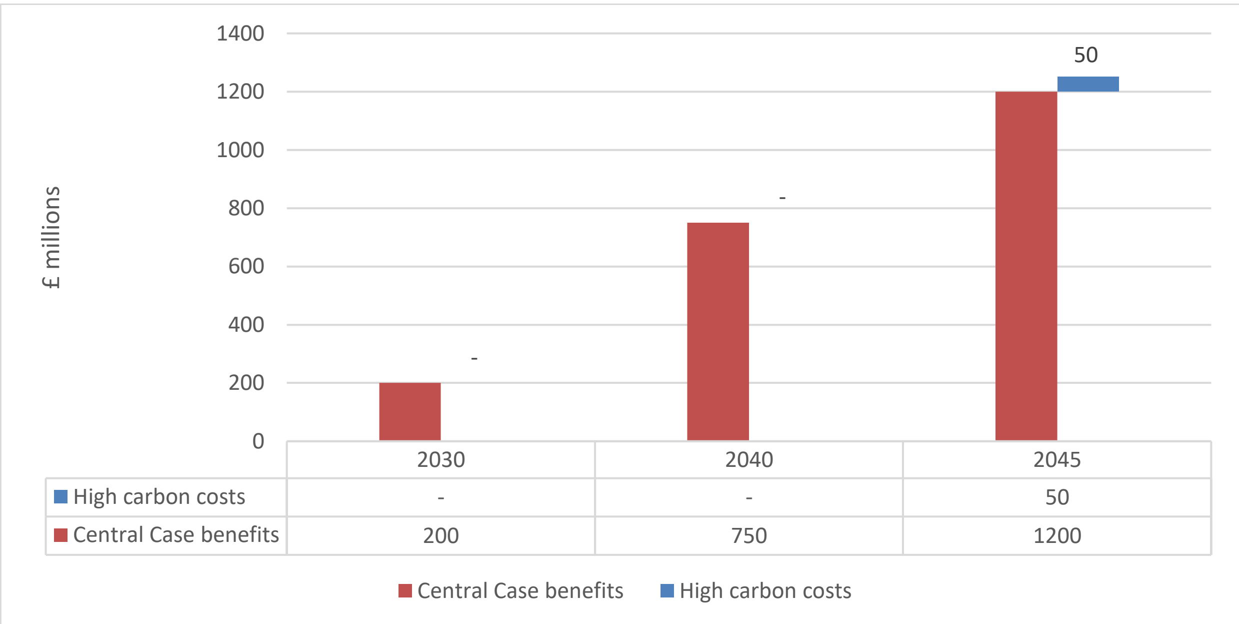
[53] We explain the difference between these figures at paragraph 4.54.

Figure 11: Estimated costs savings (£ millions) from reduction in carbon emissions, low load shifting, CFF price scenario, 2018 NPV figures, cumulative



	2030	2040	2045
Carbon cost	*	50	100
Unpriced carbon (appraisal value)	*	*	*
High carbon cost	*	50	150

Figure 12: Estimated cost savings (£ millions) from reduction in carbon emissions, low load shifting, CFF price scenario



System-wide benefits from load shifting for different implementation periods, including option 3

4.61. The system-wide benefits discussed above assume a transition period of approximately 4 years as envisaged under option 2. Benefits (and costs) are quantified according to when we expect them to be realised and up to 2045. Thus, under option 2 benefits are accounted for the period 2025-2045.

4.62. Different transition periods would affect the total quantified benefits, as the benefits would start to be realised earlier or later compared to the baseline transition period of approximately 4 years. However, to ensure comparability between the different options, the benefits are always accounted for up to 2045.

4.63. The table below shows how the benefits (of option 2) calculated using the DDM change if the transition period is extended to approximately 5 years (under option 3). Extending the transition period by 1 year would delay the realisation of benefits by 1 year. Therefore, the benefits are calculated for the period 2026-2045.

Table 17: Estimated net welfare benefits under different implementation periods, in 2018 NPV, £ millions, cumulative by 2045

Cumulative in £ millions, 2018 NPV	Different transition periods Change in net welfare by 2045		
Transition period	**4 years approx.**	**5 years approx.**	**Difference**
High load shifting scenario - CFF	£3,600m	£3,550m	-£50m
Low load shifting scenario - CFF	£1,200m	£1,200m	*

Benefits from including export-related MPANs in MHHS under option 2

4.64. In their Request for Information (**RfI**) responses, many suppliers agreed in principle that including export-related MPANs in MHHS would produce benefits. However, only a few suppliers submitted quantified estimates of the benefits. Given the high level of uncertainty at this time, we have not sought to extrapolate across the sector using the figures that those suppliers provided.

4.65. Some large suppliers told us that mandating settlement of export would bring more accurate settlement, and one mentioned that it would enable the alignment of settlements and payments for export. They added, however, that these benefits would depend on effective delivery of the Smart Export Guarantee (**SEG**).

4.66. Other suppliers mentioned ongoing benefits expected from improved forecasting. An independent supplier agreed that including export MPANs would bring forecasting benefits and said that it would also reduce risk because unsettled, exported energy would no longer be smeared across parties through the Grid Supply Point Group (**GSPG**) Correction Factor. Two suppliers, one large and one independent, stated that mandating settlement of export would give them the right incentive to offer innovative new tariffs and products.

4.67. Other large suppliers said longer-term benefits in relation to forecasting, balancing and innovation might be limited because of the relatively small size of the sub 30 kW export market. Those large suppliers said they could not quantify these benefits for this reason. Nevertheless, these benefits would not be possible under option 3, which covers import-related MPANs only.

Better matching of supply and demand reduces balancing costs

4.68. As noted above, unmetered export volumes are spilled onto the distribution network system and this has some negative effects. It is reallocated to suppliers via the GSPG Correction process, potentially causing cross-subsidies. This spill has a significant impact on suppliers' ability to forecast and purchase energy accurately.

4.69. We expect MHHS in the medium term will lead to more accurate forecasting and matching of supply and demand, resulting in a reduction in the imbalance costs faced by suppliers as well as the residual imbalance that the ESO needs to resolve, and therefore the costs of doing so. We sought to quantify this through our RfI.

4.70. Several suppliers said that they would expect their ability to forecast to improve, and reported related cost savings amounting to £4.5m per year. We have reflected these cost savings in the total cost estimates reported in section 3 above. The ESO acknowledged that more accurate forecasting by suppliers (and better availability of data) could lead to a more balanced system and, therefore, potentially produce a relatively small reduction in the ESO’s balancing costs. The ESO did not quantify any cost savings in its response because this would depend on the extent to which suppliers improve their ability to forecast.

Better quality settlement data reduces errors

4.71. Our proposals will promote a more accurate settlement process, with better quality data and fewer settlement errors. The settlement system will increasingly use data from smart meters, removing (or minimising) the need for estimation and the current profiling arrangements. However, as part of our RfI we have not received any data that allow us to quantify this benefit. We welcome any evidence from stakeholders that would enable us to do so in the Final IA.

Shorter settlement timetable reduces collateral requirements

4.72. We propose to improve the efficiency of the settlement process by shortening the timeframes. This should reduce suppliers' exposure and the amount of collateral that suppliers must post in order to cover it. Reducing settlement collateral requirements should reduce entry barriers.[54]

Summary of monetised direct benefits

4.73. The table below sets out the total monetised direct benefits of option 2. We discuss the net impact on consumers in Chapter 6.

[54] In our Supplier Licensing Review we are consulting on proposals to ensure that the cost of mutualisation arrangements do not encourage inefficient entry or expansion of poorly-prepared suppliers. Our aim is to improve supplier standards of financial resilience without presenting any undue barriers to entry, innovation or expansion. The reduction in settlement collateral requirements would reduce any such barriers irrespective of the cost mutualisation proposal we take forward.

Table 18: Monetised estimated direct benefits for option 2, in 2018 NPV, £ millions, cumulative (2025-2045)

Summary of monetised direct benefits - MHHS option 2	2018 NPV, £ millions, cumulative (2025-2045)
System-wide net welfare benefits from load shifting	Scenario 1 (low load shifting) £1,200m
	Scenario 2 (high load shifting) £3,600m
Consumer benefits (consumer surplus) from load shifting	Scenario1 (low load shifting) £2,100m
	Scenario 2 (high load shifting) £5,050m
Benefits from including export-related MPANs in MHHS	Mostly qualitative description at this stage
Better matching of supply and demand reduces balancing costs[55]	£53m
Better quality settlement data reduces errors	Qualitative description at this stage
Shorter settlement timetable reduces collateral requirements	Qualitative description at this stage

4.74. Table 19 below summarises the different sensitivity tests discussed in this chapter.

4.75. It is worth noting that even the lowest benefit sensitivity scenario (low load shifting scenario - 2h shifting window) shows substantial positive net welfare benefits (above the costs described in Chapter 3), albeit by a significantly lower margin than our central estimate (Central Fossil Fuel prices – 8h shifting window).

[55] These benefits are included in the net costs as a cost saving.

Table 19: Summary of sensitivity analysis, shows net welfare change under the different sensitivity tests for scenario 2 in 2018 NPV, £ millions, cumulative (2025-2045)

Sensitivities summary, 2018 NPV, £ millions, cumulative by 2045	Sensitivity test	Scenario 1 (CFF, low load shifting)	Scenario 2 (CFF, high load shifting)
Baseline		£1,200m	£3,600m
Sensitivity - Net welfare change	Low Fossil Fuel Prices	£1,050m	£3,500m
	4h shifting window	£1,050m	£2,900m
	2h shifting window	£850m	£2,200m
	Including distribution network benefits	£1,300m	£4,450m
	Including High carbon costs	£1,350m	£5,600m

Table 20: Monetised direct benefits for option 3, in 2018 NPV, £M, cumulative (2026-2045)

Summary of monetised direct benefits - option 3	2018 NPV, £ millions, cumulative by 2045
System-wide net welfare benefits from load shifting	Scenario1 (low load shifting) £1,200m
	Scenario 2 (high load shifting) £3,550m
Consumer benefits (consumer surplus) from load shifting	Scenario1 (low load shifting) £2,100m
	Scenario 2 (high load shifting) £5,050m
Benefits from including export-related MPANs in MHHS	Mostly qualitative description at this stage
Better matching of supply and demand reduces balancing costs[56]	£49m
Better quality settlement data reduces errors	Qualitative description at this stage
Shorter settlement timetable reduces collateral requirements	Qualitative description at this stage

[56] These benefits are included as a cost saving in the monetised costs discussed in chapter 3.

5. Non-monetised benefits

Section summary

In this section we identify other direct benefits that we expect market-wide half-hourly settlement (**MHHS**) to bring but which are hard to value. The benefits relate mainly to increased innovation, competition and consumer engagement.

We begin by outlining the broader work we are doing to facilitate the energy transition, and other market and technological developments that we expect to see. This is the context within which MHHS will operate. Using market signals and consumption data, MHHS will place incentives on existing and new market participants to develop and offer a much wider range of innovative products and services that enable consumers to shift their electricity use away from peak times. The scale of the benefits achieved will depend on the level of consumer take-up.

Introduction

5.1. We expect that MHHS will, over the long term, deliver a variety of benefits that are hard to quantify. We base this expectation on a set of reasonable assumptions about the future development of the retail energy market and energy system, including the extent to which consumers will actually shift their consumption away from times of peak demand.

5.2. MHHS should facilitate innovation in products and services by existing and new market participants. This wider choice should directly benefit consumers. The scale of benefits depends on the extent to which consumers engage with any innovative offerings that emerge. We cannot predict that with certainty. However, our aim is to assist this transition by creating a smarter, more flexible energy system and a more competitive energy market, in particular through our work on:

- the smart meter rollout
- faster, more reliable switching
- modernising energy data

- Access and forward-looking charging reform, and
- the RIIO-2 network price controls.

5.3. For more detail about these and other projects, see the consultation document published alongside this Impact Assessment (**IA**) and our Decarbonisation Action Plan. Alongside these regulatory changes, we expect broader market impacts to arise from significant and rapid technological change in the following areas:

- electrification of transport
- electrification and decarbonisation of heat
- increased renewable generation
- energy storage solutions, and
- demand-side response (**DSR**) grid services.

5.4. Clearly, the pace of the transition to a smarter, more flexible and low carbon energy system will depend partly on the affordability of flexibility solutions and partly on the ability and willingness of consumers to engage with them. Retailers will play a critical role in developing and marketing the products and services that encourage and make it easy for consumers to use energy efficiently.

5.5. Some consumers will be confident enough to take up smart Time of Use (**ToU**) tariffs (on the basis that the tariff fits their existing behaviour or because they can easily change their behaviour). Others may choose smart options that cause the least disruption to their existing routines, or may engage indirectly through automated or managed DSR solutions. Prospective energy bill savings are likely to be a key driver of consumer decisions to engage.[57]

[57] The Ofgem Consumer Survey 2019 includes some evidence about the level of prospective savings that consumers may need in order to load shift.

Incentivising innovation

5.6. Under the existing elective settlement arrangements we have begun to see some innovative propositions. However, without access to the granular consumption data and the incentive of cost-reflective pricing, we think that innovation will not occur at the scale and pace necessary to meet the UK's net zero targets.

5.7. MHHS helps to remedy these deficiencies. It will incentivise suppliers to manage the actual costs of providing energy to their customers more efficiently. By providing access to HH consumption data (in line with privacy rules), MHHS will greatly strengthen retailers' incentives to offer:

- new energy tariff-only propositions, such as new and increasingly complex ToU tariffs (eg static, dynamic, critical peak pricing and critical peak rebate pricing)

- new third party managed energy services based on an energy proposition, eg 'heat as a service', involving use of smart controls to set an agreed level of comfort and convenience for the consumer but with remote management to efficiently deliver heating and unlock any flexibility the consumer could offer

- new bundled 'asset and tariff' offerings managed for the consumer or which could be directly controlled by actively engaged consumers (such as an EV charging and tariff bundle or an import/export tariff included with the offer of a storage battery where the consumer may already have solar PV), and

- more niche offerings that could be targeted at local communities such as peer-to-peer (**P2P**) or DSR grid balancing services.

5.8. MHHS should, therefore, play a key role in supporting innovative offers that transform the energy system and retail energy market. We have noted that faster, more reliable switching could accelerate innovation in the energy market, encouraging more and varied competitive offerings to consumers. Digitalisation (sharing consumers' granular usage data with their consent) may also be a driver for consumers to find and switch to the right offering for them. Third parties offering price comparison tools could provide a more comprehensive comparison service, taking into account the electrical appliances and other assets that a consumer owns and tailoring the service to the consumer's requirements.

Increasing competition

5.9. Market-wide settlement reform will support competition firstly by reducing the overall costs of settlement and therefore removing barriers to entry for new market players. As noted earlier, this could be through market players needing to post less collateral[58] with ELEXON in the settlement process, or realising cost savings through more accurately forecasting demand.

5.10. Exposing suppliers to the true cost of supply of their customers in every half hour period places incentives on them to encourage load shifting. This opens up an opportunity for suppliers to reduce the costs of serving their customer base, allowing those suppliers who take up this opportunity to potentially gain a competitive advantage over their competitors by offering new and innovative tariffs. Market-wide settlement reform can enable new technologies and business models that capitalise on the new incentives placed on the market, facilitating and incentivising load shifting and therefore costs reduction.

5.11. The combination of lower entry barriers and the opportunities for costs reduction, together with the new technologies and products enabled by half-hourly settlement (**HHS**), could have an important impact on competition in the market. When combined with other Ofgem projects that are seeking to support competition and innovation in the market, such as the work on Access and forward-looking charging reform and removing barriers to innovation, MHHS could have a profound impact on the dynamics of the market.

5.12. These competition effects are challenging to predict and quantify, but should be recognised as an important consequence of the project that can deliver positive outcomes for consumers. This view was shared by the Competition and Markets Authority (**CMA**) in its 2016 Energy Market Investigation, which found that the

[58] In our Supplier Licensing Review we are consulting on proposals to ensure that the cost mutualisation arrangements do not encourage inefficient entry or expansion of poorly-prepared suppliers. Our aim is to improve supplier standards of financial resilience without presenting any undue barriers to entry, innovation or expansion. The reduction in settlement collateral requirements would reduce any such barriers irrespective of the cost mutualisation proposal we take forward.

current system of load profiling reduces the competitiveness of domestic retail electricity supply.[59]

Increasing consumer choice

5.13. We expect that MHHS will facilitate more consumer choice in a future energy market stimulated by innovation. We expect that new market participants with new business models will enter the market and compete with incumbent suppliers, who in turn would evolve their existing offerings or develop new offers in response. This process would increase choice for consumers and drive down prices relative to the counterfactual. We are already beginning to see an increase in choice through new smart ToU tariffs and aggregation services targeted particularly at those consumers with existing flexibility assets.

5.14. There could also be broad-based energy services where the tariff is part of a bigger 'bundle' that includes a flexibility asset. The growth potential of these offers may be linked to the willingness of consumers to make data available about their usage to providers. Consumers that opt out of sharing their granular energy data may have a more limited choice of products and services.

5.15. We expect that MHHS will facilitate innovation, new entry and greater choice of products and services. For many, this means opportunity - to get a better service, save money and help the environment. For others, particularly more vulnerable consumers, this will be more of a challenge and they may need extra support and protection.

[59] See the CMA's Energy Market Investigation (2016), page 591.

6. Consumer impacts

Section summary

In this section, we bring together the quantitative and qualitative analysis from previous sections of the Impact Assessment (**IA**) in order to draw conclusions about which option will deliver the best outcomes for consumers. We summarise the potential distributional impacts of market-wide half-hourly settlement (**MHHS**) amongst consumers, including rural consumers and consumers with protected characteristics under the Equality Act 2010.

Alongside this draft IA, we have separately published a more detailed paper examining the potential impact of MHHS on consumers.

Net direct and indirect consumer impacts

6.1. The table below sets out the net position for consumers after taking account of monetised costs and benefits under option 2 (our preferred option) relative to the counterfactual. It makes clear that **MHHS under option 2 is expected to have a significant net benefit for consumers compared with the counterfactual.**

Table 21: Summary of estimated net impacts under option 2, 2018 NPV, cumulative costs and benefits by 2045, £ millions

Summary of net benefits - option 2	Low Shifting (scenario 1)			High Shifting (scenario 2)		
Total monetised benefits for consumers	£2,100m			£5,050m		
	Costs - low case	Costs – central case	Costs - high case	Costs - low case	Costs – central case	Costs - High case
Total monetised costs	£399.7m	£492.5m	£591.9m	£399.7m	£492.5m	£591.9m
Net Benefits of MHHS	£1,700.3m	**£1,607.5m**	£1,508.1m	£4,650.3m	**£4,557.5m**	£4,458.1m

6.2. The tables below set out the net position for consumers under option 3 and compare the net impacts of options 2 and 3.

Table 22: Summary of net impacts under option 3, 2018 NPV, cumulative costs and benefits by 2045, £ millions

Summary of net benefits - option 3	Low Shifting (scenario 1)			High Shifting (scenario 2)		
Total monetised benefits for consumers	£2,100m			£5,050m		
Uncertainty Cost range	Costs - low case	Costs – central case	Costs - high case	Costs - low case	Costs – central case	Costs - high case
Total monetised costs	£380.6m	£467.7m	£560.6m	£380.6m	£467.7m	£560.6m
Net Benefits for consumers	£1,719.4m	**£1,632.3m**	£1,539.4m	£4,669.4m	**£4,582.3m**	£4,489.4m

Table 23: Net benefit comparison of options 2 and 3, 2018 NPV, cumulative net benefits by 2045, £ millions

Comparison of net benefits to consumers	Low Load Shifting (scenario 1)	High Load Shifting (scenario 2)
Option 2	£1,607.5m	£4,557.5m
Option 3	£1,632.3m	£4,582.3m
Difference in net quantified benefits	**-£24.8m**	**-£24.8m**
Non-monetised benefits	Option 2 brings benefits from settling export in terms of improved network management, more accurate settlement, better forecasting and through increased innovation, competition and consumer engagement (see sections 4 and 5 above)	

Distributional impacts on consumers

6.3. The preceding tables summarise the net impacts of the options we have considered for consumers in the aggregate. However, changes to the energy system facilitated by MHHS are likely to affect different customers in different ways depending on their individual circumstances. We set out below the work that has been done to estimate the potential distributional impacts on different types of energy consumer. This includes rural and regional effects and impacts on consumers with protected characteristics under the Equality Act.

6.4. We have considered the distributional impacts on household energy bills of taking up specific Time of Use (**ToU**) tariffs, where electricity prices vary across the day, compared with remaining on 'flat' tariffs where the price paid is the same regardless of when the electricity is used. There is a risk that some customers might sign up to ToU tariffs even though they have little ability to shift consumption away from more expensive, peak periods. There is also a risk that, if enough customers switch to ToU products, the customers left on flat tariffs will see their prices go up.

Previous work on identifying MHHS distributional impacts

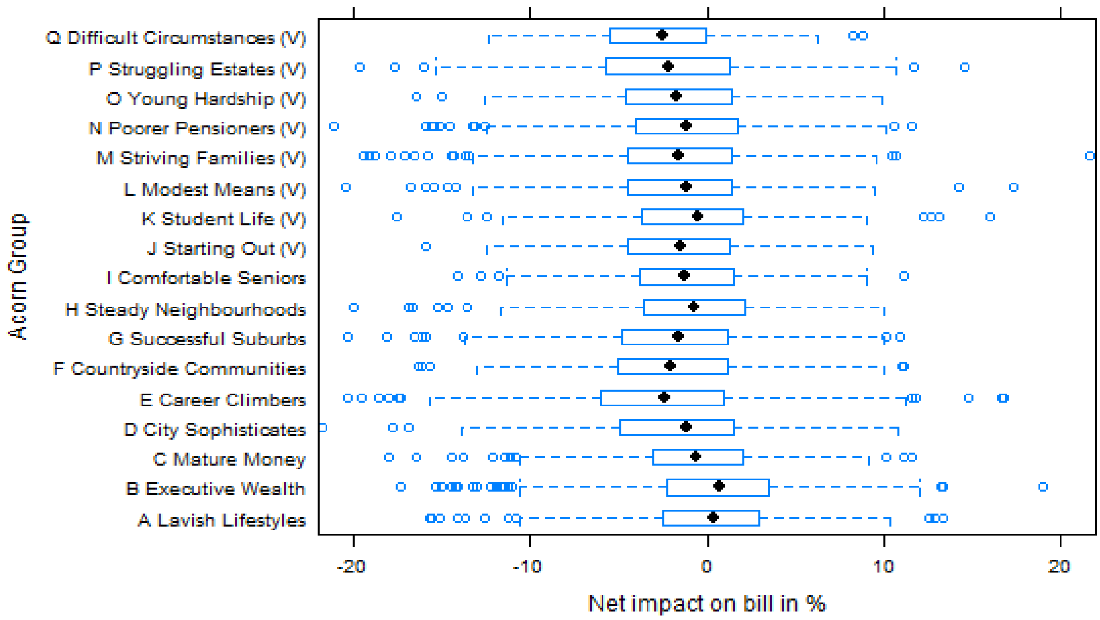
6.5. In the Outline Business Case, we referred to analysis we commissioned in 2016 from Cambridge Economic Policy Associates (**CEPA**) about distributional impacts across defined sociodemographic groups of consumers of them taking up static ToU tariffs compared to staying on flat tariffs.[60] MHHS will incentivise energy providers to offer consumers a variety of different types of 'smart' (static, dynamic and real-time) ToU tariffs. CEPA assessed the distributional impacts using the datasets of domestic consumers that were involved in smart meter trials, using the ACORN classification to differentiate consumers by sociodemographic group.[61]

6.6. CEPA noted how different groups of consumers might respond to different motivations and incentives, such as achieving a certain defined level of bill savings. Most consumers across the different sociodemographic groups, including groups of consumers in vulnerable situations but excepting some of the most well-off groups, could make, on average, a modest bill saving (2% in the case of vulnerable consumer groups) by moving to a static ToU tariff compared with staying on a flat tariff. This took into account consumers' predicted demand response with a ToU tariff.[62] However, a wide range of positive and negative energy bill impacts within all

[60] See page 66 of the MHHS Outline Business Case as well as the full CEPA report (July 2017).
[61] ACORN is a powerful consumer classification tool that segments the UK's population by analysing demographic data, social factors, population and consumer behaviour to help provide an insight into different types of people.
[62] Specifically, CEPA designed their tariff scenarios to assume that if consumers do not change their consumption, the bill of the average customer will remain unchanged relative to what they would have paid under an existing

of the groups was possible, regardless of whether consumers responded to ToU price signals or not (the dotted line bars in the figure below). If consumers chose not to take up a ToU tariff, they would not suffer a loss.[63]

Figure 13: Impact on bill in relative terms under static ToU reference tariff (% net impact compared to a flat tariff), assuming customers adjust consumption to tariff



Linking with Ofgem's distributional impacts framework

6.7. Ofgem is in the process of developing a flexible framework to help us measure the potential distributional impacts of our policies on different types of consumers.[64] As more data becomes available to us, for example, as more consumers' actual smart data is settled on a half-hourly basis, we will aim to fine tune the framework to improve our understanding of these distributional impacts.

flat tariff. Thereafter, building in consumers' predicted demand response accounts for the modest rise in average bills for the most well-off groups and a modest decrease in average bills for most lower income groups.

[63] See chapter 4 of the CEPA report.

[64] See our decision on the Consumer Vulnerability Strategy 2025 for more details about the planned consumer archetypes refresh (paragraphs 9.2 to 9.4).

6.8. To date, there is limited evidence quantifying the potential distributional impacts across specific consumer groups of implementing MHHS and whether consumers will respond to the flexibility options it may facilitate. The CEPA analysis was useful in assessing these impacts but the limitations in the datasets used were recognised.[65]

6.9. Robust and meaningful distributional impacts analysis may depend upon how consumers are categorised (into broad or narrowly defined groups) and the quality of the datasets available. Taking the analysis one step further would involve establishing a more informed view of how consumers may respond to price signals, whether directly or indirectly, and their propensity to change behaviour and load shift. This could help us identify whether specific policy levers may prompt a greater or lesser response from consumers to help achieve a more efficient, flexible and low carbon energy system.

6.10. In order to more effectively frame any distributional impacts analysis we plan to undertake in the future, we are updating the consumer archetypes originally developed for us in 2012 to assist in assessing the impacts on different consumer groups of Ofgem's policies.[66] The current archetypes segment GB households into twelve consumer groups based on socio-economic characteristics. We can use the archetypes to look at the average consumption levels of different groups of consumers rather than using a 'broad average', as well as characteristics including age, disability status, income level and the number of dependents. Using this rich and detailed data, we can build a narrative about how policy may affect different consumer groups.

6.11. It is challenging for us to set out a quantifiable distributional impact analysis across different categories of domestic consumers without a robust evidence base. However, our continued and timely development of the policy tools highlighted above may help us to provide more robust analytical assessment of distributional impacts for the Full Business Case (**FBC**). We had planned to publish the FBC in autumn 2020 but now expect to do so in spring 2021.

[65] These limitations (using London-only consumers from the Low Carbon London trial and excluding a higher proportion of vulnerable consumers) could have skewed the results obtained by CEPA.
[66] See the archetypes 2014 update here.

6.12. Recent work from Dr Timur Yunusov and Professor Jacopo Torriti of Reading University gives some indications of the potential impact of ToU tariffs on different family types, assuming no load shifting. The impact varies very significantly with the assumptions made about the nature of the ToU tariff.[67]

6.13. They found that high-income couples without children would be the most adversely impacted (or least positively impacted) family group (in relation to the other family groups studied) if they chose to take up a ToU tariff and did not change their consumption pattern. Conversely, and in relative terms, low income single parents are among the family groups who would benefit most (or lose least).

6.14. The paper noted some limitations to the analysis. In particular, the use of historical regional datasets where only households' smart meter data was available to use is insufficient to understand the distributional effects of ToU tariffs unless this data is also enriched by sociodemographic parameters, which are currently not contained in publicly available sources.

6.15. The gains and losses shown in Yunusov and Torriti's work would only apply if a customer in a particular group took up a ToU tariff and did not change consumption behaviour. In practice, we expect that those taking up a ToU tariff would usually do so either because they could benefit from it without changing their behaviour or because they could easily change their behaviour in order to benefit from it. Technology like batteries (perhaps communal ones shared between apartments in a block of flats), smart appliances, or electric vehicles (**EVs**) equipped with smart chargers will increasingly help consumers to realise those benefits.

Impacts on consumers living in remote rural areas

6.16. In remote rural areas, the cost of maintaining and operating the distribution networks may be higher than other areas. MHHS could facilitate innovative local solutions in remote communities. One possibility is self- or third party-managed energy storage alongside renewable generation (wind or solar PV) that offers a

[67] See Yunusov, T. and Torriti J. (2020), 'Distributional effects of Time of Use tariffs based on smart meter electricity demand and time use activities', Energy Policy (submitted). This paper has been co-authored by Dr Timur Yunusov and Professor Jacopo Torriti of Reading University.

balancing service to the local grid - a Virtual Power Plant (**VPP**). This could produce demand–side response (**DSR**) and revenue generating opportunities.

6.17. Remote communities could offer local DSR services, allowing them to sell excess electricity flexibly when the energy system needs it while retaining access to, and use of, the broader energy system when their demand exceeds supply. Such services could contribute to a more efficient local energy system in remote rural areas. Trials are under way in the Orkneys and in Cornwall.[68]

6.18. In remote areas of northern Scotland, Wales and England, electricity is the main fuel for heating as well as for lighting. In off-gas grid areas, domestic consumers could be encouraged to take up electric smart heating solutions, such as heat pump installation by individual households and/or by local communities, controlled directly by them or as a third party-managed DSR solution. Such offers could be more energy efficient and 'greener' than connecting to the gas grid. However, there may be access and affordability challenges in relation to installing and paying for them.[69]

6.19. EVs offer consumers access to, and use of, a flexible asset. For those in remote areas, a key issue will be access to convenient EV charging points. Statistically, those living in remote areas with private transport need to travel greater distances.[70] Having a robust local energy system could help them. Smarter and more flexible energy grids may be required, for example by developing community-based energy solutions linked to renewable generation. Otherwise, costly significant infrastructure upgrades may be needed.[71] Upgrades across different regions may also vary.

[68] See the Solo Energy case study on our website. Solo Energy is offering some domestic consumers on Orkney a storage battery solution managed by them as part of a local DSR service. Also, Centrica is currently trialling the offer of local DSR services from domestic and non-domestic consumers with renewable generation capability through its Cornwall Local Energy initiative.
[69] There are examples of trials of 'heat as a service' concepts involving smart heating controlled through smartphone apps and smart thermostats which participating consumers have broadly supported as providing appropriate levels of comfort and which help them save on their energy costs. There is more information about one trial, the Smart Systems and Heat (SSH) programme, which is being managed and delivered by the Energy Systems Catapult and which could usefully apply to consumers in remote areas.
[70] See the most recent Department for Transport (DfT) statistics from the National Travel Survey showing that rural car use (by mileage per person) is significantly higher compared to urban car use.
[71] For example, there is more information here about Transport Scotland's vision to increase the number of EV charging points across a key trunk road connecting rural to urban Scotland, the Electric A9 project.

Regional impacts

6.20. We have no quantitative evidence that introducing MHHS would directly affect different parts of the country in significantly different ways. We would be interested in any evidence that indicates that there could be differential regional impacts. Factors that we might expect to contribute to some variations across regions include:

- different working patterns and commuting times, leading to somewhat different peak consumption times
- differing proportions of household types, since both the CEPA research and Yunusov and Torriti's work suggest that, on average, the impact of ToU tariffs varies with household type, and
- differing network structures. MHHS could help reduce the need for costly network reinforcements. Any impacts may differ across regions, based on the scope for such reductions and strength of charging signals. Our work on Access and forward-looking charging reform is considering options which could increase the granularity of network charging signals.[72]

Equality Act 2010 impacts

6.21. Changes facilitated by MHHS could have particular impacts on certain consumer groups falling within the definition of having 'protected characteristics'.[73] These include disability and age. Some of these consumers will feel better equipped to deal with these impacts than others (for example, if they are tech savvy, happy to share data in return for a bill saving and actively engage in a smarter, more flexible market).

[72] See the recent open letter on our shortlisted policy options for more detail.
[73] See here for a definition of protected characteristics. Ofgem has a statutory duty under the Equalities Act 2010 to have regard to the wider range of groups with protected characteristics to ensure the elimination of discrimination and advancing equality of opportunity for these groups.

6.22. Consistent with our Consumer Vulnerability Strategy (CVS 2025),[74] we want all consumers to share in these benefits and not be left behind. Some impacts may have more relevance for consumers with protected characteristics:

- engagement and understanding energy usage and ability to change behaviour – we recognise that some consumers may struggle with digital tools such as smartphone apps, and could need additional support or specific tools to help them engage, understand their usage, and make informed choices about any flexibility they could offer and the right product choice for them. For example, depending on their circumstances, elderly consumers and people with disabilities may need more specific support from their energy provider than other consumers. This means providing appropriate advice, help and usable tools that assist these consumers' understanding.[75] Some stakeholders have suggested that an independent source of advice to support them in a more sophisticated energy market may be needed

- affordability and access issues – some consumers may have greater difficulty accessing certain flexibility products and services due to their cost and physical location. This may particularly affect certain consumers in social housing, on low incomes or those living in private rented accommodation where landlords must agree to install flexibility options such as smart appliances or storage batteries. Affordability concerns could be overcome by pooling resources, for example at community level. However, some consumers with protected characteristics may need more support to understand the implications for them

- consumer protection issues – we expect MHHS to incentivise the development of a range of new products and services that encourage consumers to shift their energy consumption. Some of these offerings – such as smart ToU tariffs or bundled flexibility options - might be relatively complex. Consumers with protected characteristics may need tailored support from their energy provider to engage with and benefit from them.

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[74] The Consumer Vulnerability Strategy 2025 is on our website.
[75] Our Consumer Survey 2019 found that 55% of disabled consumers are disengaged from the market because they have not switched supplier in the last 12 months. This figure rises to 61% for financially constrained consumers (which is defined as being on a prepayment tariff, in arrears on their energy bills, or in receipt of means tested benefits). These consumers have relatively low levels of confidence in engaging with suppliers and lower levels of knowledge about the energy market.

6.23. Consumers will need to have confidence that they will be protected no matter what energy products or services they adopt, or from whom. Consumers also need to be confident about engaging with their energy provider when things go wrong and, if they remain dissatisfied, about using redress mechanisms to put things right. For our part, we believe principles-based regulation is appropriate for regulating the new products and services that we expect MHHS to encourage. However, we will keep this under review if evidence emerges that any specific new protections may be needed. As set out in our Decarbonisation Action Plan, we will ensure that consumers who cannot provide flexibility are not unduly disadvantaged.

7. Risks, assumptions, monitoring and evaluation

Section summary

In this section we describe the risks we have considered and the assumptions we have made in drawing up the options for market-wide half-hourly settlement (**MHHS**). We also set out how we propose to monitor and evaluate the new settlement arrangements. We ask stakeholders to bear this in mind in terms of the datasets that they keep.

Risks

7.1. We have considered several potential risks relating to MHHS. Broadly, these cover:

- **transitional risks** while the industry prepares for and implements MHHS, including interdependencies with other programmes that could affect the quality and speed of delivery
- **ongoing post-implementation risks**, such as:
  - consumer concern about sharing HH consumption data
  - low uptake of smart tariffs (such as time of use tariffs) and
  - conversely, the potential distributional impacts that may arise if the take-up of such tariffs is widespread.

Transitional risks

7.2. The transition to MHHS will bring a resource-intensive period of system design, development and testing that will require committed engagement from many stakeholders. The project is running at the same time as other projects aiming to transform the retail market. We have been working to understand and address resource challenges arising from them. We have considered the extent of any resource overlaps especially in relation to the Switching Programme, which was projected to conclude in the summer of 2021 but is now subject to a 6-month planned delay in response to the ongoing COVID-19 situation.

7.3. In the consultation document we seek views on our proposals for managing the detailed design and implementation phases to ensure that new settlement arrangements are introduced on time and to a high standard. We believe the proposed transition period of approximately 4 years is challenging but that, with effective programme governance, it is likely to be achievable – however, our consultation seeks stakeholder views on the impact of COVID-19 on this and we are keeping timescales for the project under review.

Ongoing post-implementation risks

7.4. MHHS will enable the development and delivery of new products and services that should produce long lasting consumer and wider societal benefits. The scale of benefits that can be achieved depends on the successful rollout of smart meters, the levels of data available for settlement, and the resulting market and consumer response.

7.5. This in turn will depend on factors such the state of competition in the market, the environment for innovation, and the value of flexibility stemming from wholesale price variations and Access and forward-looking charging reforms. The direction we take on each of these projects will affect the balance of signals that suppliers and consumers face, and influence the extent to which suppliers and other energy/service providers develop new products and services making use of customers' smart meter data, the take up rate of these offerings by consumers and how much they shift their usage from peak times.

7.6. As a result, there remains substantial uncertainty over the exact nature and scale of the impact of our reforms. Coupled with the challenges of taking a long term view, we have imperfect data on the costs to industry of delivering our reforms and significant uncertainty over future price developments. Given this uncertainty, we have carried out a number of sensitivity analyses and are consulting on our assumptions.

Consumers opting-out of providing HH consumption data

7.7. The volume of granular data available for settlement will impact on the benefits that can be achieved. At present suppliers may collect data from their domestic customers at daily granularity by default, though the customer may opt-out to monthly granularity, unless the data is required for a regulated purpose. We understand that opt-out rates under the current arrangements are low, with a number of suppliers reporting single-digit percentages.

7.8. In determining an appropriate data sharing framework for settlement purposes, we must strike a balance between consumers' rights to privacy over their data and the system-wide benefits that we expect to result from the reforms if enough quality data is entered into the system. We think that, if too many consumers opted out to monthly resolution of data collection for settlement, the benefits of the reforms will be impacted.

7.9. We have set out that the party responsible for settlement will have a legal obligation to collect HH data for settlement purposes, unless the domestic consumer opts out of this processing. Microbusiness customers will not be able to opt-out. We have also set out that data collected for settlement purposes can also be used for forecasting. Where the consumer does opt out, whilst the current backstop would then be monthly resolution of data collection, we are consulting on our proposal that daily resolution data should be collected for these purposes instead, including asking for views on what would be a proportionate arrangement for existing customers who already have their smart meters.

7.10. Effective supplier messaging about the benefits of sharing data for settlement should further mitigate that risk. Consumers must be made aware of why their HH consumption data is required and the benefits that sharing it can bring, so that they can make an informed choice as to their data sharing preferences. We think that, if the messaging is inadequate, inconsistent or confusing to consumers, opt-out rates will increase. We also however recognise that settlement and forecasting are difficult concepts for suppliers to discuss with their customers. We are therefore also consulting on whether there may be a role for a central body to play in assisting with consumer messaging around settlement and forecasting, to ensure consumers are duly informed with accurate and consistent information.

Storing HH data securely

7.11. Under the Design Working Group's (**DWG**) preferred Target Operating Model (**TOM**), non-aggregated data would be made available to the Balancing and Settlement Code (**BSC**) central settlement systems for the purpose of calculating the settlement imbalance. However, the DWG preferred TOM design has not set out where the non-aggregated data would be held or how it would be accessed. It could be held in multiple stores or in a single data hub.

7.12. Any access to this data would be subject to privacy safeguards and would have to be in compliance with data protection legislation, including the General Data Protection Regulation (**GDPR**).[76] There is general agreement within industry that there should be no gatekeepers to data and those that should, or want to, access that data (under the right security and governance controls) should be able to quickly and easily.

7.13. The Architecture Working Group (**AWG**)[77] will assess and design the most appropriate solution, taking into account security, viability and cost, and the degree to which it facilitates future adaptation of the system. The AWG will consult on its recommendations and then submit them to the Ofgem senior responsible officer (**SRO**) for a decision later this year.

Estimating the benefits of MHHS

7.14. We have adopted mechanisms to test the conclusion that option 2 will maximise net benefits for consumers. These mechanisms are:

- identifying ranges for monetised direct costs and benefits of option 2
- using a power market model to assess the potential benefits of a more flexible energy system enabled by MHHS, which quantifies the benefit of consumer load shifting under different scenarios and sensitivities, and

[76] Regulation (EU) 2016/679 (General Data Protection Regulation).
[77] For further detail see here.

- engaging extensively with industry participants on the proposals.

7.15. Through these approaches, we are testing whether option 2 will maximise net benefits to consumers under a range of plausible assumptions and scenarios.

Monitoring and evaluation

7.16. Introducing MHHS is a major undertaking that involves complex changes to IT systems and operating processes across the industry. As such, it requires careful and detailed planning and effective supervision. We have considered what governance arrangements are necessary to assure timely and high quality delivery. Subject to our decision in the Full Business Case, we expect to rely on those governance arrangements to ensure that all relevant parties meet their deliverables by the final deadline for migrating Meter Point Administration Numbers (**MPANs**) to the new settlement arrangements.

7.17. Ofgem intends to continue to rely on the existing Performance Assurance Framework to monitor ongoing settlement performance quality. Should experience of the new settlement arrangements suggest that improvements could be made, we will expect industry parties to pursue them in the usual way by raising code modification proposals.

7.18. For our part, we envisage routine monitoring of load shifting trends and opt-out rates. We are still considering the precise scope of the information that we will want to gather and the frequency with which we will want to request it. Stakeholders will, however, appreciate the importance that we attach to maintaining good quality datasets in relation to consumer load shifting and opt-outs. This and other information will inform a review of the data access arrangements and help us to determine whether they remain proportionate and consistent with delivering the objectives of settlement reform. We expect to carry out this review no later than 3 years after the end of the transition period. However, we will only undertake the review when we feel we have sufficient evidence to do so.

Appendices

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Appendix 1

How the Dynamic Dispatch Model and the Distribution Networks Model work

Dynamic Dispatch Model (DDM)

1.1. The DDM models the electricity wholesale market and investment in new plant. To model the market, the model calculates the short run marginal cost of every generation plant for each half-hourly (**HH**) period across each sample day using assumptions input by the user. From this, it constructs the merit order of supply, which is then matched to demand, entered as an input, to derive the equilibrium wholesale market price.

1.2. Daily demand is allocated between the HH periods that make up a day by the model using demand load curves. This is repeated for the DDM's 22 sample days. The load shifting constraint is applied to give an estimate of how much load can be shifted from each HH period. This shiftable load is then reallocated between HH periods.

1.3. Shifting between periods is constrained by a limit on the number of hours by which demand can be shifted. This is entered as an assumption by the user. HH periods are ordered by the level of demand: the HH periods with the lowest demand are shifted to first. For each period to which demand is shifted, the DSR technologies[78] that could shift demand to that period are ordered by the amount of demand they could shift: the DSR technology that can shift the least to that period is shifted first.

Distribution Networks Model (DNM)

1.4. Built in 2017-18, the DNM models the GB electricity distribution network costs from 2010 to 2050. It comprises a Power Flow Model **(PFM)** and an Investment Model **(IM)**. The model uses representative network archetypes based on actual existing distribution networks in Great Britain to calculate changes in reinforcement costs under different scenarios. The model uses four representative "base networks" – a base urban network, a base rural network, a meshed/Manweb-type network and a London network. These base networks are used together with regional demand and loading data to create ten regional

[78] For example: electric vehicles (**EVs**) or heat pumps.

networks – reflecting South of England, North of England, Scotland, West Midlands & Wales and London.

1.5. The PFM utilises power flow algorithms to model electricity flows through these representative networks. The power flows directly depend on the scenario inputs specified by the user to estimate future network breaches and constraints (in the form of thermal or voltage constraints). These inputs consist of peak/minimum demand profiles, Distributed Generation **(DG)** profiles, and varying levels of DSR.

1.6. All these inputs are taken from the DDM, which is run separately. As DNOs are required (by the "N-1" reliability criterion) to reinforce their networks to cope with worst case network contingencies, the DNM similarly models worst-case scenarios for electricity network operators: a maximum (system peak) demand with minimum DG scenario, and a low demand maximum DG scenario.

1.7. The model possesses a list of solutions that can be used for network reinforcement to address the network constraints identified by the PFM. The IM uses a cost function and financial modelling to optimise solution selection by DNOs (looking at the total capital and operating expenditure) of installing all these solutions in the representative networks) in order to reinforce the networks. The DNM, therefore, replicates the process that a DNO would go through when assessing a network. The IM also allows for the modelling of different investment strategies and foresight assumptions.

1.8. The IM uses 'conventional' and 'smart' solutions to reinforce its representative networks. Conventional solutions consist of a variety of standard network reinforcement (overhead lines, underground cabling and the installation of pole or ground mounted transformers). Smart solutions consist of demand or generation constraint services, special voltage and thermal regulating instruments and active network management/network reconfiguration. Smart solutions can be turned on and off.

1.9. To calculate GB-wide costs, the outputs from the two models are upscaled based on predetermined 'scaling factors'. All the assumptions used to build the model are based on widely accepted industry standards (Smart Grid Forum WS3[79] & WS7[80]).

[79] See our report 'Assessing the Impact of Low Carbon Technologies on Great Britain's Power Distribution Networks'.
[80] For more detail, see the 'Work Stream 7' page of the Energy Networks Association website.

Appendix 2

Load shifting assumptions

Factual

1.10. Table 24 shows the range of estimates for the proportion of customers with a smart tariff and the percent of demand shifted at peak by customers with a smart tariff, and the resulting estimate of the range for system load shifting that can be attributable to market-wide half-hourly settlement (MHHS) (except for heat pumps demand).

Table 24: Estimated system peak demand shifting attributable to MHHS (with sources and notes)

	% of consumers on smart tariffs (A)	% of peak demand shifted per consumer (average) (B)	% of system peak demand shift (A)x(B)
Upper bound 2025	20% Fell et al (2015)[81]	30% Trials: Octopus (2018)[82], CBS (2016)[83], Faruqui (2013)[84] and BEIS' Smart meter roll-out CBA (2019)[85]	**6%**
Upper bound 2045	60% Baringa (2012)[86]: supported by new evidence on take-up of EVs and heat pumps (which were used as a proxy for take up of smart tariffs)	50% Baringa (2012): optimistic assumption based on high level of smart technology take-up like battery storage. BEIS' Smart meter roll-out CBA (2019)	**30%**

[81] Public acceptability of domestic demand-side response in Great Britain: The role of automation and direct load.
[82] Octopus - agile report (2018).
[83] Final Report on Customer Acceptance, Retention and Response to Time-Based Rates from the Consumer Behavior Studies (CBS).
[84] Faruqui and Sergici's (2013) Demand Response summary from 163 tariff pilots from US, Australia and France amongst others.
[85] Department for Business, Energy and Industrial Strategy, 'Smart meter rollout: cost benefit analysis 2019.'
[86] Baringa, 'Electricity System Analysis – future system benefits from selected DSR scenarios.'

Lower bound 2025	10% Baringa (2012), CBS (2016), Citizens Advice (2017)[87]: conservative assumption compared to the expected uptake of smart appliances such as EVs and heat pumps (used as a proxy for take up of smart tariffs)	10% Baringa (2012), CBS (2016), CLNR[88]: conservative compared to Octopus and others results. Consistent with little to no automation	**1%**
Lower bound 2045	30% Baringa (2012): conservative assumption compared to the expected uptake of smart appliances such as EVs and heat pumps (used as a proxy for take up of smart tariffs)	20% Baringa (2012): conservative compared to Octopus (2018) results and others. Consistent with little automation	**6%**

1.11. We have decided not to include any additional load shifting from heat pumps in options 2 and 3. This is a conservative measure that undervalues the benefits of MHHS. It also reflects the difficulty of calculating the potential of load shifting under MHHS compared to elective and the fact that heat pump users might have the highest incentive to take up Time of Use (**ToU**) tariffs even under the elective settlement arrangements.

Rationale for the counterfactual

1.12. Estimating the level of load shifting under the counterfactual (the elective half-hourly (**HH**) arrangements) is not straightforward because little data about load shifting to date is available. Using the information available to us, we analysed the incentives on suppliers to develop and offer smart tariffs to different types of consumer, and for those consumers to take them up.

[87] UCL/Brattle for Citizens Advice: The Value of Time of Use Tariffs in Great Britain.
[88] A summary of the results can be found in this CLNR report.

Incentives on suppliers

1.13. Elective half-hourly settlement (**HHS**) alone is unlikely to deliver the levels of half-hourly settled customers to achieve this scale of load shifting, and a move to HHS on a market-wide basis is needed to place the right incentives on the market to deliver a significant level of load shifting. This view was shared by the Competition and Markets Authority (**CMA**) in its 2016 Energy Market Investigation, where it found that "elective half-hourly settlement is unlikely to be an effective substitute for full, mandatory half-hourly settlement. This is because under mandatory settlement, all suppliers bear the full costs that their customers impose on the electricity system". The CMA also highlighted concerns around cherry-picking, recognising that while elective HHS may enable individual suppliers to make cost savings, overall system costs would be unlikely to fall under elective HHS and the potential benefits of HHS would not be realised.

1.14. Without implementing HHS on a market-wide basis, there is only a limited incentive for suppliers to elect to half-hourly settle their customers, and therefore far less of an incentive to develop and offer new products and innovations to help customers shift their consumption away from peak periods. This limited incentive means the levels of HHS we expect to see under elective HHS will not be enough to realise load shifting of the scale necessary to deliver benefits to consumers from avoided network and generation investment.

1.15. HHS also exposes suppliers to risks (as well as opportunities), which suppliers may well be unwilling to elect to take on. Firstly, the current profiling arrangements provide suppliers with a degree of protection against variability in customers' consumption patterns and predictability in terms of their forecast shape, and suppliers may not wish to take on the risks of moving to HHS, even if it would open new market opportunities. Secondly, there are risks around the level of take-up of the products and innovations enabled by HHS, which may deter some suppliers from being a first-mover in the market, or adopting HHS at all.

1.16. With elective HHS, we are far less likely to find solutions across the market that can bring forward the types of tariffs and innovations on a scale that will really influence the level of acceptance and adoption of these. Market-wide settlement reform will help in this regard, by exposing suppliers to a new incentive to help their customers to shift their consumption away from peak periods. This is supported by the responses to our Request for Information (**RfI**) (2019).

Incentives on consumers

Domestic - relatively low users

1.17. Suppliers have had little incentive to offer demand-side response (**DSR**) products and consumers little incentive to take them up. We think that the potential for aggregated levels of load shifting of this sector of the market under elective is negligible (note that to achieve 1% of load shifting we would need 10% of take-up of smart tariffs and 10% of average peak reduction).

Domestic - high energy users/electric vehicle (EV) users

1.18. Significant load shifting could be achieved in this sector under the elective arrangements, particularly for EV users. Suppliers could decide to offer smart products (for example, because of competition and product differentiation dynamics) even if they are not exposed to the costs. However, suppliers could find ways of appealing to these users other than ToU tariffs. For example, they could offer cheaper rates for consuming above a certain volume of consumption.

1.19. We have calculated the level of load shifting in the counterfactual based on the information available to us, allowing for some increase over the period 2025-2045.

Domestic - high energy users – heat pump users

1.20. We have taken BEIS's assumption (2018 BEIS reference case) that demand from heat pumps is 90% shiftable but just by one hour, reflecting the higher incentive of these users to take up ToU tariffs even under elective. Note that our assumption is the same in the factual and in the counterfactual, which is a conservative approach, as explained above.

Domestic - high energy users – other electric heating

1.21. We have assumed very little to no flexibility from these users because it is very difficult to offer flexibility if not paired up with battery storage.

Non-domestic EV users

1.22. We have assumed that there is no load shifting from these users on the basis that vehicles used for business operations might be less flexible than for domestic use, or might need a higher incentive. This is in line with the level of load shifting from EV non-domestic demand in the 2018 BEIS reference case.

Small non-domestic consumers

1.23. Given the relative lack of consumer demand for ToU products to date, and the lack of incentive on suppliers proactively to develop them, we assume very little load shifting from these consumers under the elective arrangements.