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P379 Impact Assessment

Elexon

23 March 2020

FINAL REPORT

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Contents

1. EXECUTIVE SUMMARY

P379[2] would allow multiple suppliers to supply energy volumes at a single customer meter point without needing to establish an agreement between all of the suppliers involved. The modification seeks to overcome perceived barriers to dynamic competition for behind-the-meter energy volumes, and thereby enable innovation beyond that currently observed. Consideration of these issues are amplified by the UK's Net Zero targets and the volumes of new renewable energy installations, electric vehicles (EVs) and heat pumps needed to meet this ambition. The proposer envisages that P379 could unlock more varied 'energy as a service' offers for dynamic loads such as EVs.

P379 has been developed through a series of industry workgroups since it was raised in January 2019. Nevertheless, important questions remain surrounding detailed elements of the change design, reflecting the complexity of the P379 solution. P379 is necessarily limited to changes within the scope of the Balancing and Settlement Code (BSC); however, many of the detailed design requirements would require broader changes beyond the BSC and hence, outside of the scope of development thus far. In addition, many of the potential use cases of meter splitting are hypothetical and the extent of cost and benefit is dependent on several assumptions/trends such as the level of take-up of meter splitting. This context has informed our analytical approach and we highlight remaining elements of uncertainty throughout this report.

Our approach

In this report, we present a cost-benefit analysis (CBA) of BSC Modification P379. The stage of development, remaining complexity of the solution and the range of hypothetical benefits attributed to P379 have driven the structure of our CBA approach which can be summarised as 'break-even analysis'.

We draw on a combination of quantitative and qualitative consultation responses to develop an indicative assessment of the order of magnitude of direct implementation and ongoing operational costs. We consider the relative importance of fixed, up-front costs which would be needed regardless of uptake levels and of variable costs that would vary with the number of consumers who choose to adopt multiple supply.

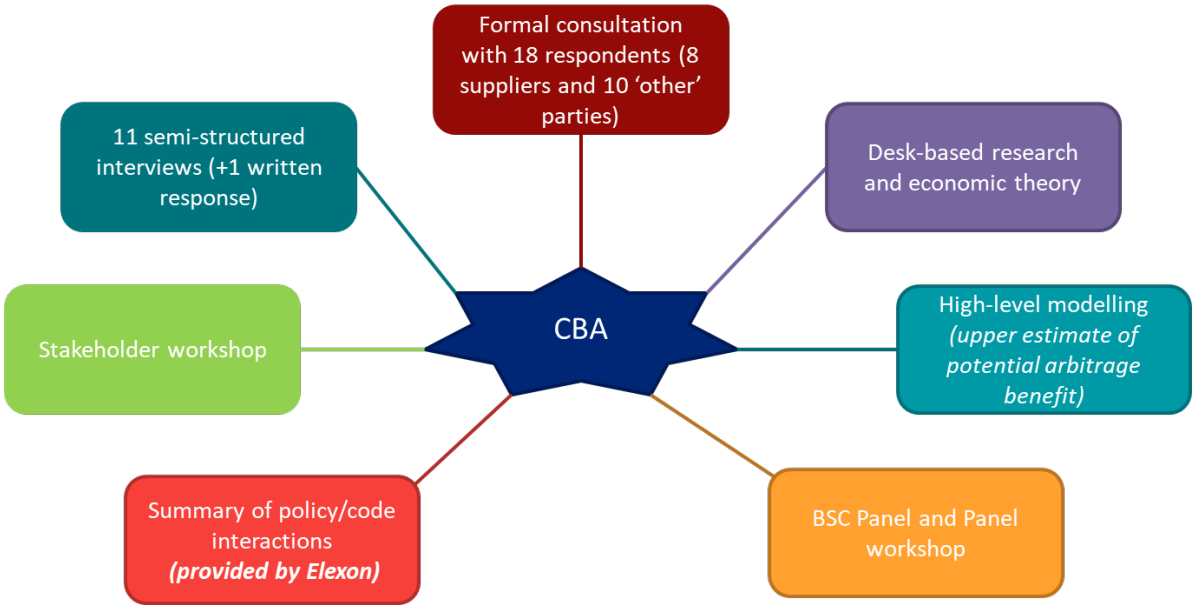
We then carry out an assessment of the potential benefits of P379 by setting out and appraising four potential use case categories for meter splitting. Combining stakeholder input with our own analysis, we develop a view on the likelihood and materiality of potential benefit in relation to each of these categories. We structure our analysis by considering the barriers which P379 could help to alleviate and the importance of this barrier in relation to the use case in question. We also consider whether there are alternative means of achieving the same benefit through existing market arrangements or under industry change that is already in progress.

We also assess the potential for distributional impacts to arise as a result of P379 and for risks and unintended consequences. These risks and unintended consequences include opportunity costs given the extent of industry resource required to finalise and implement P379, and the potential for this to conflict with other industry priorities.

We have drawn on several sources of evidence to develop our analysis. We summarise these sources of evidence in Figure 1.1.

[2] https://www.elexon.co.uk/mod-proposal/p379/

Figure 1.1: Sources of evidence used to inform our CBA



Assessment of costs

The finalisation and implementation of P379 would undoubtedly constitute large, complex change.

While the extent of direct financial costs remains subject to a broad degree of uncertainty, the few numerical cost estimates that we received from stakeholders allow us to develop very indicative 'order of magnitude' estimates of implementation costs for domestic suppliers. These responses indicate discounted costs for implementation within the domestic consumer base of between £84 million and £526 million over our 10-year appraisal period at low take up levels of 0.1%. At more optimistic take-up levels of 10%, cost estimates rise to between £2.3 billion and £2.6 billion. Implementation across non-domestic consumers would increase costs further.

These cost estimates also demonstrate the relative importance of fixed costs that may be required regardless of uptake of meter splitting. This suggests the need for a good level of certainty regarding uptake rates of P379 to ensure that these up-front fixed costs would ultimately be justified by a sufficient level of consumer benefit.

In addition to suppliers, P379 would have impacts on a broad range of industry participants and we have summarised many of the key stakeholders who would be affected by the change in this report. Nevertheless, our analysis of the evidence base submitted by stakeholders suggests that it is primarily changes to electricity supplier systems and processes that would drive most of the direct financial cost.

Assessment of benefits

In our engagements with stakeholders, those in favour of P379 set out their view that meter splitting could make a material contribution to delivering a decarbonised and decentralised electricity market. They describe a market in which there is high penetration of EVs, heat pumps and other flexible loads and highlight the potential for meter splitting to encourage regarding how these assets are used by suppliers and other industry participants. They emphasise the importance of unknown innovation that may emerge in the presence of meter splitting opportunities. And they identify related markets from which new types of offers and services may enter into the electricity market – e.g., through bundling of EV and heat pump sales with 'Transport as a Service' (TaaS) and 'Heat as a Service' (HaaS) offers.

To inform our assessment, we attempt to evaluate the extent of more certain benefit through the identified use cases. We perform this assessment taking into account alternative 'routes to market' for the innovation being considered and based on an assessment of the materiality of barriers that P379 would alleviate, in isolation of other changes to the market.

We identify the greatest scope for benefit in relation to the potential for specialist suppliers and bundling of offers for large, separable loads (primarily EVs and heat pumps). Based on our analysis, we estimate low or low - medium materiality of benefit for the remaining three use cases as we do not consider that P379 would overcome a material barrier to enable benefit. We summarise our assessment of the likelihood of benefit emerging, the maximum scale of possible benefit and timescales for possible benefit in Table 1.1.

We agree with stakeholders that the establishment of meter splitting may introduce an environment within which innovative products and services may emerge that would not otherwise. In performing this CBA, we note that it is inherently difficult to forecast some of these innovation related benefits with certainty since much of this innovation is, almost by definition, currently not present in the market.

Table 1.1: Summary of benefits

Use case	Likelihood of some benefit	Maximum scale of possible benefit	Timescale of benefit
Consumer price arbitrage	Low-Medium	Low-Medium (of welfare benefit)	Medium-term
Specialist suppliers and bundling	Medium-High	Medium	Medium-term
Community energy	Low-Medium	Low-Medium	Short-term
Peer-to-peer trading	Low	Low	Long-term

We anticipate that P379 could facilitate the emergence of specialist suppliers and bundling of offers for large, separable loads (primarily EVs and heat pumps). However, we identify two factors which limit the scale of this incremental benefit associated with P379:

1. **Innovation is already emerging in relation to specialist services for large, separable loads**: Several suppliers already have innovative EV offers. Innovative offerings for heat pump users are also starting to emerge[3]. We heard from stakeholders who are active in development of retail innovation who suggested that P379 could have the perverse effect of focussing additional cost and risk on suppliers who are at the leading edge of innovation in the market. This is because these suppliers are more likely to have customers who would tend to adopt secondary supply and may face a disproportionate percentage of the implementation costs. We also note that BSC modification P375[4] allows industry parties to access flexible loads behind the boundary meter point for balancing purposes and so may substitute for some of the benefit which may be assigned to P379.
2. **Routes to market exist for innovative entry from outside the electricity sector**: Some of the innovation that is emerging in this area of the market is being developed through partnerships between suppliers and specialist technology companies. As part of our stakeholder engagement, we spoke to an EV manufacturer and to a supplier of heating and hot water solutions who is working on development of HaaS offerings. Both had some interest in potential opportunities presented by secondary supply but considered their primary route to market to be through partnerships with existing suppliers, particularly in the near to medium term.

Distributional effects

We identify the scope for P379 to have distributional effects, both in relation to competition between different types of supplier and in relation to its impacts on consumers. In both cases, the nature and extent of distributional impact would be dependent on detailed P379 design decisions.

[3] See for example 'Octopus Go', 'Ovo – EV Everywhere', 'Good Energy Green Heat', etc

[4] https://www.elexon.co.uk/mod-proposal/p375/

For each of our use cases, we would expect take-up to be more prevalent with engaged consumers, and we would expect the majority of benefit to go to those who have adopted certain technologies such as EVs or heat pumps. For these reasons, we would expect the existence of consumer benefit to be skewed towards higher-income groups, at least in the near to medium term before adoption of these technologies becomes more prevalent across society.

Many of the respondents to our consultation noted additional cost and risk that would fall on primary suppliers to implement P379 and, in particular, in the case that their customers chose to adopt secondary supply. This suggests that P379 could introduce a need to recover some additional costs from consumers. The extent of distributional effects will also depend on how these additional costs are recovered. To the extent that additional costs related to take-up can be targeted on consumers who adopt secondary supply, then this would limit the extent to which benefits for those who adopt secondary supply are subsidised by those who do not. However, this may be difficult to achieve in practice. Where additional costs to suppliers are effectively socialised, this would exacerbate distributional effects.

In addition to distributional impacts on consumers, respondents noted that there may also be distributional impacts on suppliers. This includes the potential for unfair competition between primary and secondary suppliers as well as distributional impacts between primary suppliers with customers who are more and less likely to adopt secondary supply.

Risks and unintended consequences

In addition to direct financial costs, we also assessed the potential for broader risks and unintended consequences of P379 and gathered input from industry stakeholders to support this assessment. These risks and unintended consequences generally fall into one of three categories:

1. **Impacts on competition:** The P379 solution differentiates between primary and secondary supplier responsibilities, for example in relation to network charging. Several stakeholders identified the potential for this to impact on competition, both between primary and secondary suppliers, but also with knock on impacts for competition between different types of primary suppliers. They also identified the scope for new challenges regarding supplier disputes and supplier failure.
2. **Impacts on the consumer experience:** Multiple supplier arrangements would introduce new complexities into the customer experience, including the need for multiple points of contact with suppliers, uncertainty regarding responsibilities between suppliers, billing, settlement and metering arrangements. We note that unintended consequences in relation to the customer experience would primarily affect consumers who voluntarily chose to adopt secondary supply which may provide some protection.
3. **Opportunity costs:** Regardless of the route that is chosen for finalisation and implementation, P379 would require a large amount of industry resource to finalise and implement over the coming years. Many stakeholders noted major ongoing industry change such as the smart meter rollout, market wide half hourly settlement (MHHS) and the Access and Forward-Looking Charging Significant Code Review (SCR)[5] that require substantial industry effort to progress. Many of these industry changes have objectives which interact strongly with the use cases that we have identified for meter splitting. A minority of stakeholders identified some synergies between these changes and implementation of P379 that could reduce costs to some degree. However, informed by the majority of consultation responses, we consider that other areas of change may act as enablers of some of the potential benefit associated with P379 and may help to minimise costs. By competing for resources with these other projects, implementation of P379 now could undermine its own benefits case.

[5] https://www.ofgem.gov.uk/electricity/transmission-networks/charging/reform-network-access-and-forward-looking-charges

Conclusion

We have identified a range of direct financial costs, risks and unintended consequences, and opportunity costs in this report. Together, our assessment indicates the need for a high degree of certainty and materiality of potential benefits to deliver a positive CBA under our 'break-even' analytical framework. Our analysis does not provide us with sufficient confidence in the magnitude of benefits to achieve this at the current time.

We acknowledge challenges in estimating the magnitude of unknown innovation that could emerge in the presence of meter splitting that would not otherwise. However, we believe that a significant amount of weight would need to be placed on the emergence of unknown innovation, which is by nature uncertain, to counterbalance identified costs and yield a positive CBA.

Both the costs and benefits of P379 may be affected by ongoing developments in the electricity sector. In relation to costs, several suppliers noted that implementation following MHHS could reduce cost requirements significantly. We have also identified ongoing 'enabler' projects, including MHHS and the smart meter rollout that may establish the conditions within which innovation using meter splitting becomes increasingly viable. In our view, delivery of these projects and adaptation by consumers should be prioritised ahead of P379 which could otherwise compete for limited industry resources.

Alongside these industry changes, trends in the supply and demand of electricity may also allow for greater certainty as to the potential appetite for meter splitting. On the supply side, our stakeholder engagement suggests that EV and heat pump manufacturers are considering market entry strategies but do not currently believe that a lack of meter splitting presents a short-term barrier to their intentions. On the demand side, the consumer appetite for innovative use of EVs, heat pumps and other loads will help to identify whether gaps exist in the innovation which is already being delivered. Given the up-front costs of implementing P379, greater certainty of benefit would help to establish if take-up is likely to be at a sufficient level to warrant the inherent up-front complexity and cost.

It is difficult to provide a definitive timeframe for when meter splitting may need to be re-considered. However, we suggest that there would need to be sufficient time for material developments to emerge in each of the areas set out above. A period of around five years would allow for implementation and consumer experience of MHHS, the smart meter rollout and changes to charging arrangements under the Access and Forward-Looking SCR. It is also in line with the assessment of the potential for structural change to EV and HaaS business models set out by the stakeholders that we spoke to.

2. CONTEXT

In this section we summarise the P379 solution and the stage of development. We summarise the scope of our study and set out the structure of this report.

2.1. WHAT IS THE CHANGE BEING CONSIDERED?

P379 is a proposed modification to the BSC[6] that was initially raised in January 2019. P379 would allow multiple suppliers to supply energy volumes at a single customer meter point without needing to establish an agreement between all of the suppliers involved.

Currently, multiple suppliers are not able to easily compete for energy volumes behind the customer meter. While some arrangements exist within the Supplier Volume Allocation (SVA) shared metering arrangements[7], they require contractual agreements between suppliers in advance. P379 was proposed with the intention of enhancing competition by enabling multiple suppliers to access energy volumes at a single meter point without the need for such agreements.

The P379 solution

Under the solution that has been developed, the supplier for each customer meter will remain responsible for the meter itself and for the 'main supply'. This 'primary supplier' will effectively retain their existing obligations under the electricity supplier licence conditions[8]. Electricity customers will be able to choose to have a proportion of their electricity (up to 100%) provided by a 'secondary supplier'. The secondary supplier will be able to supply pre-agreed fixed volumes or percentages of a customer's demand or provide electricity volumes which are recorded by Asset Meters, located behind the boundary meter point.

Secondary supply arrangements would be fed into the electricity settlement process such that the primary and secondary supplier are settled against appropriate electricity volumes. There are two alternative options for how settlement is finalised. Under Option 1, meter splitting calculations are performed using the BSC central systems. Under Option 2, these meter splitting calculations are decentralised and performed by the primary supplier's half hourly data collector (HHDC).[9]

2.2. WHAT STAGE OF DEVELOPMENT IS THE SOLUTION AT?

BSC modifications go through several steps before being implemented. The modifications are developed by industry workgroups until a detailed solution is finalised. The modification is then presented to the BSC Panel who vote on whether to recommend to Ofgem that the modification should be implemented or not. The Gas and Electricity Markets Authority (GEMA) make the final decision on whether a modification is implemented. GEMA can decide to accept or reject a modification or to send it back to Elexon for further development.

[6] https://www.elexon.co.uk/bsc-and-codes/balancing-settlement-code/

[7] Section 2.5: https://www.elexon.co.uk/documents/bsc-codes/bsc-sections/bsc-section-k-classification-and-registration-of-metering-systems-and-bm-units/

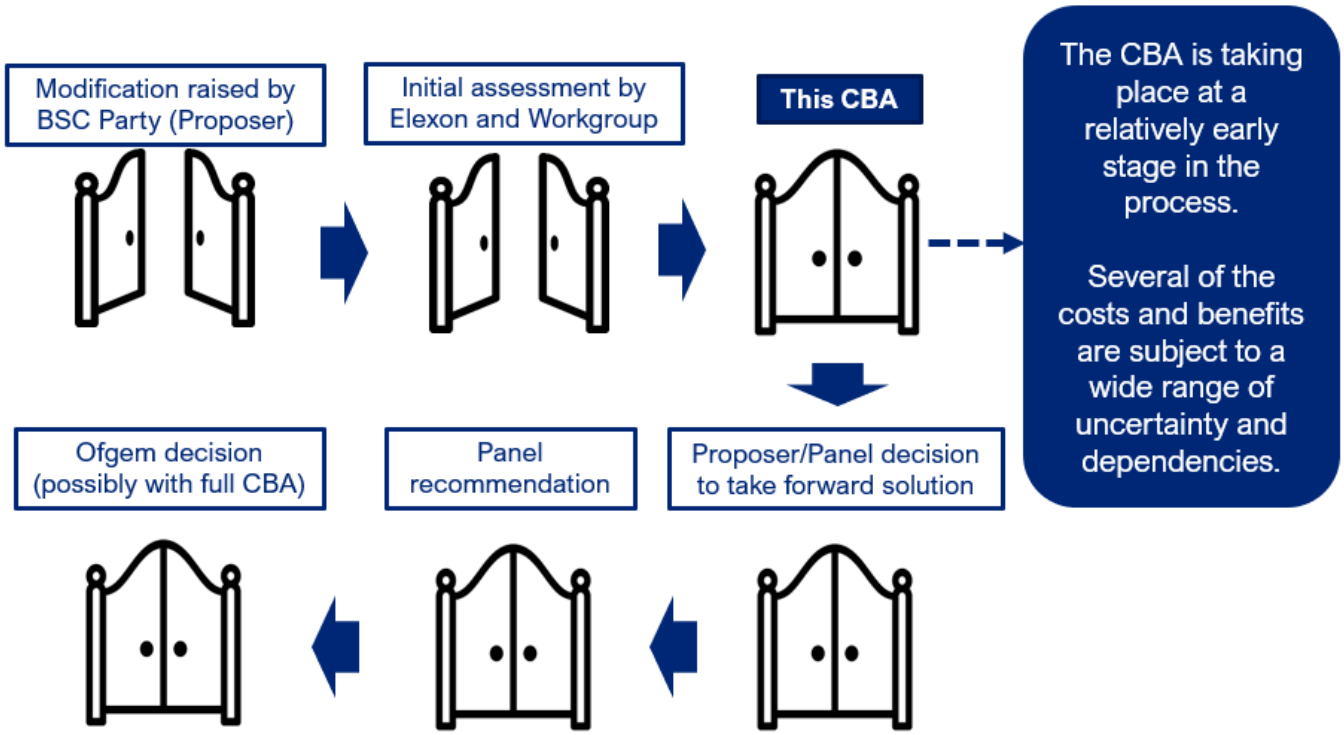
[8] https://www.ofgem.gov.uk/licences-industry-codes-and-standards/licences/licence-conditions

[9] More detail on the proposed solution can be found in Elexon's Second Interim Assessment Report: https://www.elexon.co.uk/documents/second-p379-interim-assessment-report/

The P379 design solution is inherently complex and has been designed over the course of 12 BSC industry workgroups. Two 'Interim Assessment Reports' have been published on the modification[10]. Nevertheless, there are some complex design challenges remaining in the development of the solution. As part of an industry workshop that we held to gather stakeholder views on P379, we asked stakeholders at what stage they considered the solution to be at. 92% of those who responded said that they felt the solution was at the 'Initial Product Definition' stage and stressed the challenges involved in providing informed estimates of costs and benefits at this stage.

Our CBA is being undertaken at a time when further development of the solution may be needed before the BSC Panel is able to make a recommendation. The CBA marks a 'gateway' designed to support the BSC Panel and the modification sponsor in determining whether to take the solution forward for detailed design development (see Figure 2.1).

Figure 2.1: 'Gateways' for the P379 modification



2.3. Scope of this study

Elexon commissioned CEPA to develop a CBA of P379. The CBA is intended to feed into a decision for the modification proposer and the BSC Panel regarding whether to take forward P379 for further development. Depending on this decision, the CBA may also feed into the Panel's view on a recommendation to Ofgem regarding whether or not to approve P379.

As this CBA is taking place at a relatively early stage of development of the solution, stakeholders have indicated some of the challenges with developing an informed and accurate estimate of costs. In addition, many of the potential benefits of P379 that we have explored under this CBA are difficult to quantify. Where quantification is possible, the magnitude of potential benefit is heavily dependent on assumptions in relation to the effectiveness of P379 in changing customer behaviour – e.g., in relation to take-up of secondary supplier opportunities. For this

[10] First Interim Assessment Report: https://www.elexon.co.uk/documents/change/modifications/p351-p400/p379-interim-assessment-report/

Second Interim Assessment Report: https://www.elexon.co.uk/documents/second-p379-interim-assessment-report/

reason, much of our analysis remains qualitative. Where we do present quantitative estimates, these should be considered as indicative and assessed with caution as they are subject to a wide bound of uncertainty.

Many stakeholders communicated to us the interactions between P379 and other areas of the energy industry arrangements, touching upon industry codes other than the BSC, licence arrangements for primary and secondary suppliers and ongoing industry reform such as the Access and Forward-Looking Charging SCR being undertaken by Ofgem and the review of Exempt Supplier status being undertaken by BEIS. It is not within scope of CEPA's work to collate these interactions. However, Elexon has developed an assessment of inter-dependencies which we include as an annex to this CBA.

2.4. Structure of this report

The remainder of this report is structured as follows:

- In Section 3, we describe our CBA methodology, at a high-level and in relation to specific analysis of costs and benefits.
- In Section 4, we set out our assessment of direct financial costs to suppliers and other affected industry participants.
- In Section 5, we describe and assess the four use cases for meter splitting under P379, setting out our assessment of the likelihood, potential magnitude and time horizon for anticipated benefits.
- In Section 6, we discuss the potential for P379 to lead to distributional impacts. We consider the potential for distributional impacts on suppliers as well as consumers.
- In Section 7, we discuss areas of risk and potential unintended consequences. These should be taken into account alongside the more direct financial costs in considering the merits of P379.
- In Section 8, we bring this analysis together to consider the balance of costs and benefits within the framework of our break-even analysis.
- In Appendix A, we summarise our stakeholder engagement including interactions with the BSC Panel, a summary of our industry workshop, more detail on cost estimates submitted in response to our formal consultation and our bilateral engagements with stakeholders.

3. METHODOLOGY

In this section, we summarise the methodological approach that we adopted for this CBA. We discuss the high-level analytical approach as well as the specific methodology used for our assessment of costs and benefits.

3.1. ANALYTICAL APPROACH

3.1.1. Break-even analysis

Our high-level approach can be summarised as 'break-even analysis'. We consider the assumptions and conditions under which the magnitude of potential benefit derived through the identified use cases for meter splitting would be sufficient to outweigh the expected order of magnitude of costs.

We previously set out the challenges involved in quantifying costs and benefits, given the stage of development of the proposed modification and several uncertainties in relation to the benefits that could be realised.

Therefore, we do not aim to develop a fully quantified CBA as this would be heavily driven by the assumptions that would be required. Instead, we develop an assessment of the magnitude of potential costs which draws on both quantitative and qualitative stakeholder input. In addition to direct financial costs on suppliers and on other industry participants, we also consider the relevance of risks and unintended consequences of change including opportunity costs in relation to wider industry change.

While this cost estimate remains subject to a high degree of uncertainty, it provides an indication of the level of benefit that we would need to observe to yield a positive CBA. Drawing on this analysis of the magnitude of costs, our 'break-even analysis' is designed to consider under what assumptions/conditions the scale of expected benefit could be sufficient to justify these costs.

3.1.2. Sources of evidence

We drew on a range of evidence to inform our CBA. Table 3.1 summarises the sources of evidence and how we applied them to develop our CBA.

Table 3.1: Sources of evidence

Source of evidence	Application
Previous engagement on development of P379	We assessed previous engagement on P379 to develop and articulate theoretical use cases for meter splitting. We developed a hypothesis for the barrier that P379 would help to remove that would allow for benefit to emerge in relation to each use case. We also assessed previous engagement to understand some of the potential for cost impacts, risks and unintended consequences.
Desk-based research and economic theory	We combined our assessment of previous engagement on P379 with desk-based research and economic theory to consider how meter splitting may affect consumers and competition in the retail electricity sector and the potential materiality of benefits that could arise in relation to each of our use cases.
Stakeholder workshop	We used a stakeholder workshop to gather input from as broad a range of stakeholders as possible. This workshop was used to test the hypothetical use cases with stakeholders as well as to seek input on costs, risks and unintended consequences. 54 participants joined the stakeholder workshop, with broad representation from a range of stakeholder types.
BSC Panel meetings	We attended two Panel meetings and held a separate Panel workshop to gather feedback on our intended methodological approach and to communicate our developing conclusions.
Formal consultation responses	We gathered input on direct financial cost impacts through a formal consultation. The consultation also provided an additional opportunity for stakeholders to comment on the envisaged use cases. We asked stakeholders to provide justification for their cost estimates to the extent possible. When reviewing responses, we considered the justification that had been provided by stakeholders to inform our views on costs. We received responses to our consultation from 18 stakeholders. Eight of these respondents were electricity suppliers and 10 represented other industry participants (e.g., code bodies, distribution network owners, supplier agents, etc)
Bilateral semi-structured interviews	After developing well formulated hypotheses for potential meter splitting use cases, we wanted to test these use cases in depth with a range of stakeholders. A particular aim of our bilateral interviews was to reach a broad representation of stakeholders, in particular to discuss each use case with a stakeholder who we may expect to have some interest in the area. We provide a summary of the bilateral interviews in Appendix A.
High-level modelling	In general, we did not attempt to develop quantification of the magnitude of benefit associated with each of the use cases we identified. However, we did identify the opportunity for high-level modelling to inform an indication of the potential order of magnitude of benefit in relation to the 'Price Arbitrage' use case. We discuss our modelling methodology in further detail in Section 5.3.1.

3.2. Time horizon for analysis

We assessed costs and benefits over a 10-year timeframe, from 2023 – 2032 inclusive.

2023 was chosen as the first year of analysis as it is expected to be the earliest time by which P379 could be implemented. We consider 10 years to be a reasonable timeframe to assess benefits given the pace of change in the electricity sector. Meter splitting would constitute a significant change to industry arrangements that may have

impacts over such a horizon. However, following a 10-year horizon, it is possible that the market arrangements may have changed sufficiently so as to reduce the appropriateness of the analysis.

3.3. Scenarios under which analysis is being conducted

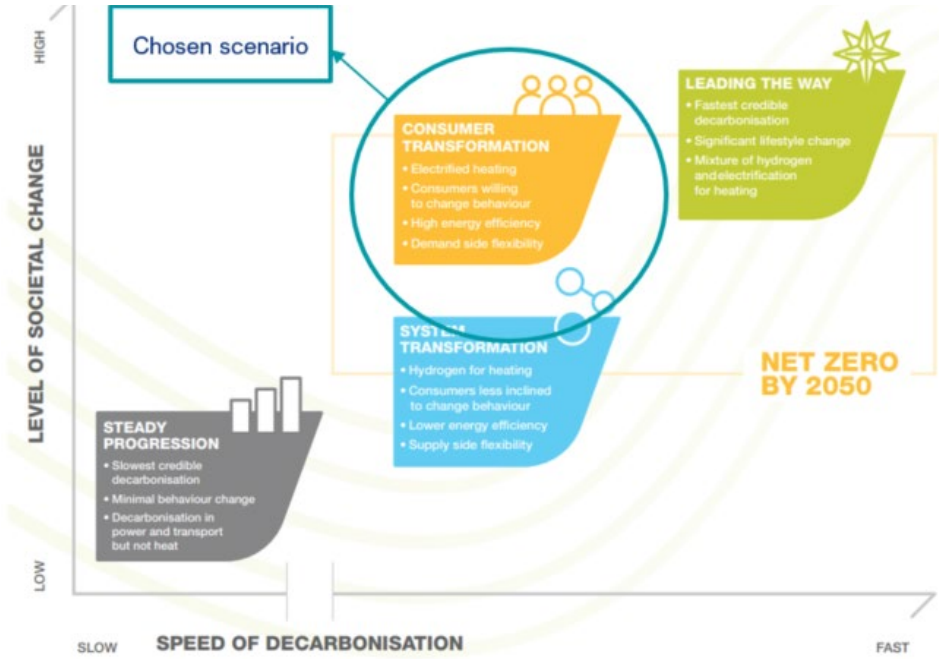
There are several uncertainties as to how the costs and benefits of P379 would develop over time in the case that it was implemented. To ensure that our CBA is developed in a way which acknowledges these uncertainties, we use scenarios to structure our analysis. We use scenarios in two ways:

1. We draw on the **Consumer Transformation** (**CT scenario)** within National Grid's Future Energy Scenarios (FES) to incorporate potential levels of uptake of consumer technologies, in particular EVs and heat pumps.
2. Some costs and benefits of P379 are likely to increase with take-up. Therefore, we develop three scenarios for the level of **'take-up'** of meter splitting opportunities by consumers. to allow us to consider how costs and benefits would be affected by consumer take-up.

3.3.1. National Grid Future Energy Scenarios

Several of the use cases for P379 relate to emerging consumer technologies such as EVs and heat pumps. In order to frame our analysis of benefits, we draw upon National Grid's FES (2020)[11]. The FES represent well established scenarios for the future direction of the energy industry and are developed through close collaboration with the industry. Figure 3.1 summarises the FES scenarios.

Figure 3.1: Future Energy Scenarios 2020



Source: National Grid

We use these scenarios primarily to establish a potential level of take-up of consumer technologies over the timeframe of our analysis. In order to establish an assessment of benefits which is toward the upper end of the range, we make use of the FES CT scenario. The CT scenario allows 2050 decarbonisation targets to be achieved, with a significant transformation in the way in which consumers use energy. The scenario has high levels of electrification of heat and transport with accelerated uptake of heat pumps and EVs out to 2050.

[11] https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2020-documents

The trends within the CT scenario help to inform both our quantitative and our qualitative analysis. Where we establish indicative quantified estimates of benefits, these are established based on technology take-up rates included in CT. While not as direct, we also develop our qualitative analysis of benefits in other areas, taking into account this pace of change.

3.3.2. Secondary supplier take-up scenarios

One of the unknowns in relation to meter splitting is the appetite from consumers to adopt a secondary supplier if this becomes an option in future. Take-up is likely to be driven by a combination of technology choice, interest and engagement in the electricity market. Our use cases suggest that consumers would choose to take up secondary supply for a particular purpose, e.g., to separate EV or heat pump load from household load, or to join a community energy scheme. Even under these circumstances, the majority of consumers may not need to or wish to go through the secondary supply route.

On the one hand, within the timeframe of our analysis, secondary supply may remain relatively 'niche', only chosen by those who are very engaged in the market and are willing to accept the potential for additional complexity given a strong rationale related to one of the use cases we are exploring. On the other hand, secondary supply may become a relatively common supply model, driven in particular by consumer choice in relation to new EV and heat pump installations.

To explore this range of possible take-up we performed analysis of costs and benefits under three 'take-up' scenarios (Figure 3.2). After engaging with the industry on our methodology, we chose to define take-up based on 0.1%, 1% and 10% of the electricity customer base. While in practice, the rationale and choice of domestic and non-domestic consumers regarding secondary supply may differ, it is not possible to say conclusively at the current time whether secondary supply would be more or less prevalent with non-domestic consumers. For this reason, we apply the take-up scenarios equally to domestic and non-domestic consumers.

Figure 3.2: Take-up scenarios

Low take-up	Medium take-up	High take-up
Primary suppliers: 0.1% of an existing supplier's customer base	**Primary suppliers**: 1% of an existing supplier's customer base	**Primary suppliers**: 10% of an existing supplier's customer base

3.4. Definition of the counterfactual

To consider the incremental cost and benefit that may be associated with P379, we need to define the counterfactual.

Under the counterfactual we have assumed that the following change is implemented:

- **The smart meter rollout**: Smart meters give consumers near real time information on energy use. Gas and electricity suppliers are required by their licence to take all reasonable steps to roll out smart meters to all of their domestic and small business customers by the end of June 2021[12]. The smart meter rollout is intended to bring several benefits to consumers and the electricity market. These include better information and more accurate billing as well as opportunities for innovation and the emergence of new sources of

[12]See Ofgem's latest update on the Smart Meter Rollout here:
https://www.ofgem.gov.uk/system/files/docs/2020/06/open_letter_2020_smart_rollout_progress_and_forward_look.pdf

flexibility. Some of the use cases that we identify for meter splitting are dependent on customers having a smart meter installed and being settled on a half hourly basis (see below).

- **Market-wide half hourly settlement (MHHS)**: Ofgem's MHHS SCR aims to ensure that the whole of the electricity market is settled on a half-hourly basis. Alongside the smart meter rollout, this is intended to act as an enabler for new products and services, such as time-of-use tariffs and other specialised retail market offers. Ofgem's draft impact assessment on MHHS[13] identifies potential benefits to consumers of between £1.6bn and £4.6bn. While timelines for MHHS are under review, Ofgem plans to publish a Full Business Case for MHHS in 2021 before publishing a statutory consultation on licence modifications later in the year. MHHS constitutes complex change and will take years to roll out following Ofgem's publication of licence conditions. Under the counterfactual, we assume that timescales align with Ofgem's most recent plan. In this plan, full implementation of MHHS is envisaged by the start of 2025. However, Ofgem indicate some re-prioritisation in light of the Covid-19 pandemic that may mean timescales for delivery of MHHS are pushed back further. We note an interaction between the timings for implementation of MHHS and possible timescales for implementation of P379. In our consultation, we asked respondents to set out how their costs would be impacted by the timing of implementation of P379 – i.e., whether implementation took place before or after implementation of MHHS.

- **P344 and P375**: BSC modification P344 was raised to align the BSC with the European Balancing Project TERRE[14]. Among other things, it allows for customers and aggregators to participate directly in the TERRE balancing services. P344 has now been implemented. BSC modification P375 is intended to allow for on-site balancing services behind the boundary meter point to be separated from imbalance-related activities. Ofgem approved P375 on 24 February 2021[15] and implementation is planned for 30 June 2022. For the purposes of our CBA, we assume that P375 (or an alternative modification which achieves similar aims) is approved and implemented ahead of P379. Together, P344 and P375 would broaden access of flexible assets to balancing services, allowing for residential and non-domestic consumers with flexible electricity assets (e.g., EVs, heat pumps or batteries) to participate in balancing services markets without needing to put in place separate metering systems.

The recent and ongoing industry change set out above may impact on the benefits case by acting as potential enablers and substitutes that we discuss in this report:

1. In some cases, the extent of benefit of P379 may be dependent on **'enablers'**. That is, benefit would only be observed, or would be enhanced if the market/regulatory arrangements had developed to allow for such benefits.
2. In other cases, alternative routes may act as **'substitutes'** for meter splitting. That is, benefit that may otherwise be associated with meter splitting could be delivered through alternate means in the absence of meter splitting. We set out our consideration of alternative ways of delivering benefit in our consideration of the use cases associated with meter splitting.

Similarly, our CBA considers the extent to which certain elements of supplier and non-supplier cost may need to be incurred even in the absence of P379, e.g., in order to deliver regulatory change in other areas such as in relation to market-wide half hourly settlement.

[13] https://www.ofgem.gov.uk/system/files/docs/2020/06/mhhs_draft_impact_assessment_consultation_-_final_-_published_17_june_2020.pdf

[14] https://www.entsoe.eu/network_codes/eb/terre/

[15] https://www.elexon.co.uk/documents/change/modifications/p351-p400/p375-ofgem-decision-letter/

3.5. Benefits assessment

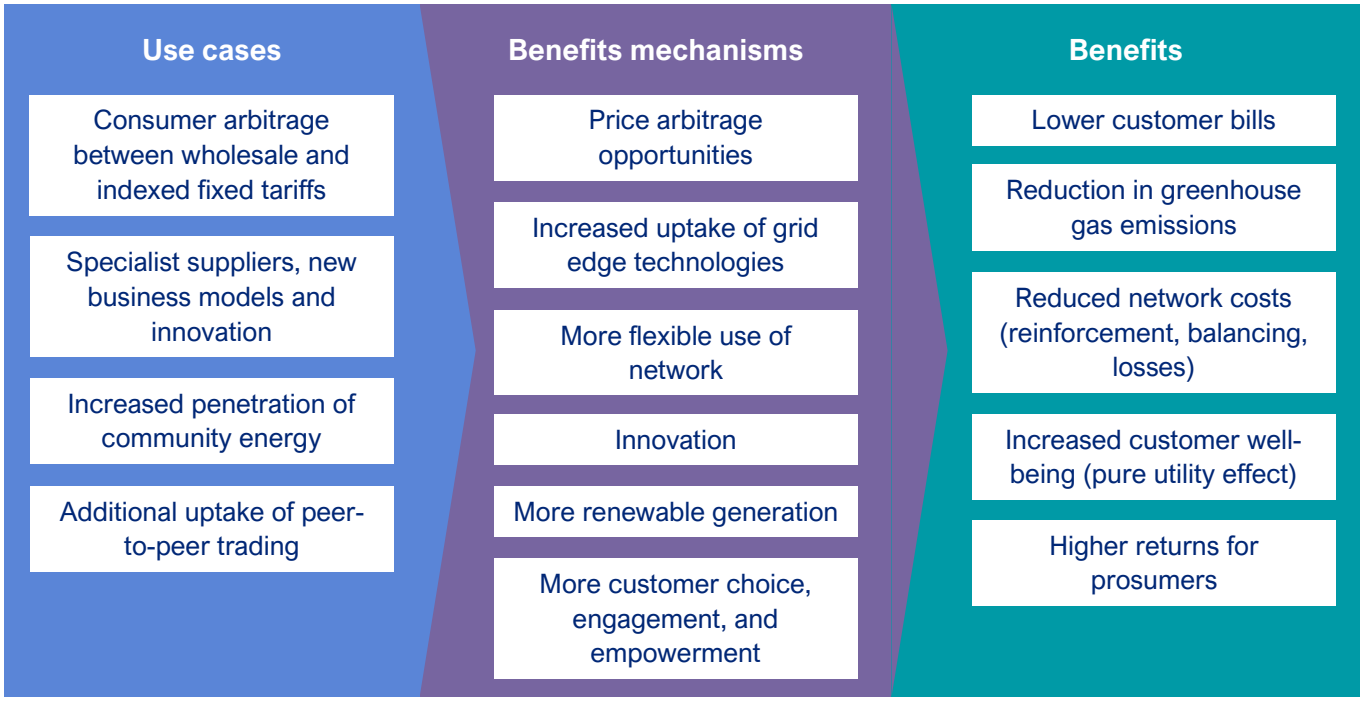
In CBAs, a benefit relates to any impact that has a positive social, economic, or environmental impact to any actor in society. Much of the commentary in relation to P379 refers to potential use cases and benefits interchangeably. In this report we have attempted to distinguish the two, separately considering the channels or use cases through which P379 might lead to benefits to society, and the ultimate benefits that exist for consumers. For example, a use case like community energy would not be considered a benefit in itself; rather the benefits from community energy would relate to the net positive impact community energy schemes have on different actors in society (e.g., where they lead to a reduction in carbon emissions).

In Figure 3.3, we map out the main use cases of P379 and the mechanisms through which they could lead to benefits. In this report, we refer to use cases as specialised markets, products or services that are designed to make the energy system operate more efficiently, reduce emissions, or provide value to consumers. The use cases we refer to have all been linked to P379, with the expectation that consumer uptake of these use cases could potentially be enabled or enhanced through the changes being proposed by P379. The main rationale is that such use cases rely on consumers being able to access, and have contractual relationships with, multiple suppliers.

Figure 3.3 outlines how each of these use cases can affect how consumers, suppliers, generators, and network operators, behave and interact. These in turn can lead to benefits for consumers, both domestic and non-domestic, or for society as a whole. For example, a use case may allow for more efficient use of network infrastructure, leading to lower network costs, and ultimately leading to lower bills for consumers. Alternatively, such use cases may increase the uptake of renewable generation, which benefits society by reducing greenhouse gas emissions.

We refer to the changes in how the system participants interact and behave as *benefits mechanisms*. Ultimately, however, we are seeking to value and assess the scale of the ultimate benefits to consumers and to society. Such benefits may not always be financial.

Figure 3.3: Potential use cases from P379 and the mechanisms through which they could lead to benefits



To assess the benefits of P379, we have taken the following three-step approach:

- **Considering barriers that P379 alleviates**: For each use case, we have attempted to assess the extent to which P379 enables or enhances the use case. Key to this is identifying the specific barriers to the use case that P379 would alleviate, assessing the materiality of these barriers, and determining whether there are

other plausible routes to market. We used existing literature and our own judgement to develop a set of hypotheses around specific barriers that could potentially exist, and then used stakeholder engagement to test these hypotheses. Through our bilateral stakeholder interviews, we focused on identifying and speaking with stakeholders with an active interest in pursuing each of these use cases, to understand the practicalities of how P379 could act as an enabler, and whether they were considering alternate approaches.

- **Assessing benefit**: The second stage of our analysis was to assess the benefits of each use case. We used economic theory to assess the potential benefits of each use case, and the mechanisms through which they may materialise. We then reviewed existing literature to collate qualitative and quantitative evidence around the potential scale of such benefits and supplemented this with stakeholder engagement. In the case of the benefit relating to arbitrage between wholesale market indexed and fixed tariffs, we have developed high-level quantitative modelling to develop indicative 'order of magnitude' estimates of the scale of potential benefits. However, given the uncertainty surrounding many of these use cases, most of our analysis has been built on qualitative evidence.
- **Considering the time horizon of benefit within which benefit may materialise**: The final stage of our analysis has been to assess the likely time horizon within which such benefits may occur. This has primarily been informed by our engagement with a range of stakeholders and has been framed within consumer trends included within the CT scenario of the FES. We have primarily considered the extent to which benefits are likely to materialise at scale within the ten-year appraisal period, or whether they require more longer-term market changes.

3.6. Assessment of direct financial costs

Costs were primarily assessed through Elexon's consultation on P379 which we helped to develop[16]. In the consultation, we sought input from suppliers and other affected industry parties in relation to the costs of implementing P379. We asked stakeholders to provide as much justification and evidence to support their cost estimates as was possible. When assessing cost submissions from stakeholders, we considered the extent of justification provided by respondents as well as any numerical estimates provided. Alongside the consultation document, we provided a cost template for the submission of numerical estimates.

We set out the supplier cost items that we explored through the consultation in Table 3.2 and the range of stakeholders other than suppliers that were covered by the consultation in Table 3.3.

[16] The consultation documents can be found here: https://www.elexon.co.uk/consultation/p379-cost-benefit-analysis-consultation/

Table 3.2: Supplier cost items explored through consultation

Stakeholder	Cost area	Summary
Primary and secondary supplier	Costs to serve	Costs to serve of primary suppliers could increase in several ways, including the following: • *Providing Terms and Conditions* • *Customer service and responding to queries* • *Development and operation of new tariff structures* • *Complexity of supply arrangements*
	Billing system costs	Primary supplier billing systems may need to be updated to provide accurate bills for customers with more than one supplier. They would need to ensure that customer bills can be adjusted based on the volumes provided by the secondary supplier.
	Settlement system costs	Under P379 Option 1, meter readings must be provided daily to the entity performing the splitting calculations for customers with more than one Supplier.
	Other IT system costs	We wanted to understand whether they may be additional IT system costs other than those identified.
	Metering costs	We asked secondary suppliers whether they may need to incur any additional metering costs, e.g., where they may not be able to rely upon appliances with built-in metering.
	Volume risk	Primary Suppliers may be exposed to the cost of managing additional risks in respect of customers with more than one supplier. Suppliers would no longer be able to rely on supplying 100% of a customer's energy volumes in any given Settlement Period.
	Compliance costs	Certain customer obligations may be more challenging to fulfil if the customer has more than one Supplier (for example provision of information, Guaranteed Standards of Service). Both the Primary and Secondary supplier would need to ensure that they continue to meet obligations they have in respect of that customer.
	Additional supplier failure	It is possible that an increase in participation from secondary suppliers, including potential new entrants, could increase the risk of supplier failures. This could impose costs of supplier failure on the rest of the industry.
	Misuse/mis-selling	We asked stakeholders whether they believed that the risk of misuse or mis-selling could increase in the case of secondary supply.
	Other costs	We asked stakeholders if there were any other costs not covered under the items above.

Table 3.3: Non-supplier cost items explored through consultation

Stakeholder	Cost area	Summary
Half hourly meter operator agents (HHMOAs)	All implementation costs	We wanted to understand whether there could be any consequential cost impacts on HHMOAs.
Half hourly data collectors (HHDCs)	All implementation costs	P379 could introduce costs in relation to systems development, qualification costs and operational costs to develop systems which can provide meter readings at higher frequency, perform meter splitting calculations, etc.
Half hourly data aggregators (HHDAs)	All implementation costs	HHDAs may face costs in order to receive, process and provide aggregated meter readings at a higher frequency than is currently required.
Smart Direct Communications Company (DCC)	All implementation costs	We asked whether there may be any additional costs to the Smart DCC, e.g., in relation to ensuring and facilitating the flow of greater volumes of data from Smart Meters.
Licensed distribution system operators	All implementation costs	Distribution charging methodologies may need to be updated to reflect the solution if implemented. We asked whether licensed distribution system operators expected to incur any additional costs from P379.
RECCo	All implementation costs	We wanted to understand whether there could be any consequential cost impacts for RECCo.
Other stakeholders	All implementation costs	We asked whether there were any other consequential cost impacts on stakeholders other than those included above.

Across all cost areas, we asked stakeholders to submit separate estimates of one-off and annual costs and to provide estimates under the three 'take-up' scenarios that we set out previously (i.e., 01%, 1% and 10%).

We did not ask for cost submissions in relation to contract notification agents (CNAs). This is because CNAs would be a new entity, required to implement P379. As such, we would not be able to gather cost estimates through consultation. However, we did take into account the potential for costs to be required to develop CNAs. We also considered the potential for some incremental costs for other stakeholders including Ofgem.

3.7. Risks and unintended consequences

In addition to direct financial costs on industry participants, we gathered evidence on the potential for P379 to introduce risks and unintended consequences. We gathered this evidence via several of the channels set out above. In particular, we asked industry stakeholders to provide views on the potential for risks and unintended consequences as part of the industry workshop and in their consultation responses. We used the bilateral semi-structured interviews to explore these risks and unintended consequences in further detail. We also applied economic theory and our understanding of the electricity market to consider the scope for these risks and unintended consequences to materialise.

At a high level, we identified three potential areas in which risks, and unintended consequences could arise:

1. **Impacts on competition:** P379 would introduce secondary suppliers and would impact on the costs and benefits base of existing supplier companies. As part of the CBA, we wanted to explore whether this could impact on effective competition between suppliers.
2. **Impacts on consumer experience:** Meter splitting would lead to the introduction of new processes for consumers across several elements of the market, including billing and information, switching and communication with suppliers (e.g., in relation to complaints and queries). We considered the potential for impacts on the customer experience as a result of these new processes.

3. **Opportunity costs:** The electricity industry is currently going through an unprecedented period of transition with several areas of complex change currently being developed by Government, Ofgem and by the industry. Difficult decisions need to be made to prioritise changes to deliver the flexible, low carbon system needed to achieve net zero. With that in mind, we considered the extent to which the development and implementation of P379 could introduce opportunity costs by reducing the effort which could be afforded to alternative areas of change.

4. ASSESSMENT OF DIRECT COSTS

In Section 3.4.2, we set out the range of direct financial costs that we anticipate may arise from the implementation of P379. Table 3.2 summarises the areas in which implementation of P379 may affect supplier costs. As part of our consultation, we asked suppliers to submit an estimate of the costs they may expect to incur in each of these areas, supported by evidence and justification wherever possible. We asked suppliers to provide estimates based on our three take-up scenarios, i.e., 0.1%, 1% and 10% of their existing consumer base. We also asked suppliers to submit separate cost items in relation to 'one-off' costs (£) and annual on-going costs (£/yr). We also asked suppliers to indicate the number of electricity customers that they serve in order to develop an estimate of the cost per customer that we could then extrapolate to the whole of the market.

In this section, we draw on consultation responses to set out analysis of the direct financial costs that may fall on suppliers Section 4.1 draws on the few quantified supplier cost estimates that we received to indicate a potential range of net present value costs for implementation for domestic consumers (discounted to £m 2021). In Section 4.2, we draw on the wider set of responses to discuss the range of costs falling on suppliers qualitatively.

We also asked industry participants other than suppliers to respond to the consultation setting out the impacts on their business and with supporting cost estimates where possible. We received 10 responses to our consultation from non-supplier entities, representing a range of industry participants that are included in Table 3.3. Two of these respondents included indicative numerical cost estimates as part of their response and several others provided cost information in their written responses. We focus on a qualitative discussion of non-supplier costs in Section 4.3 but draw on responses to summarise the order of magnitude of cost estimates where possible. While P379 would have consequential impacts on a broad range of industry participants other than suppliers, e.g., to implement new systems, processes and costs, we consider it unlikely that the direct financial costs for non-suppliers would be a significant driver of our CBA outcomes.

Elexon has proposed two alternative options for implementation of P379 with the main difference being where the splitting calculations are performed. Under Option 1, the calculations would be performed by a central system while under Option 2, the calculations would be performed by the Primary Supplier's Half Hourly Data Collector (HHDC). Only a minority of respondents identified any interactions between the chosen option and implementation costs. Where this is this case, we summarise the differences in expected impacts between options.

4.1. POTENTIAL MAGNITUDE OF QUANTIFIED COSTS FOR PRIMARY SUPPLIERS

Of the 18 respondents to our consultation, eight were from electricity supply companies. The majority of submissions noted challenges in submitting well evidenced and accurate estimates of the costs of implementing the P379 solution given some of the remaining detail to be developed in relation to the solution and given dependencies of costs on wider developments.

Supplier cost estimates

Only three of the eight suppliers who responded to the consultation were able to provide cost estimates that were broken down by cost item and into one-off and ongoing costs, and that were differentiated by cost item. In each case, justification for these cost estimates was submitted alongside the numerical responses, though noting several uncertainties. References to supplier submissions have been redacted upon request.

The suppliers that did provide cost estimates represented:

1. **Supplier A**: A large electricity and gas supplier who has been involved in the market since privatisation and is predominantly focussed on the domestic market;
2. **Supplier B**: A 'mid-tier' supplier that has entered the market more recently and has a sizable domestic consumer base; and

3. **Supplier C:** ✂ [redacted]

Based on the estimates of costs provided by these three suppliers, we have developed a cost per customer/meter point in each case. For Suppliers A and B (both primarily domestic suppliers), we extrapolated each cost per customer/meter point estimate across the overall customer base to estimate costs for the total domestic customer base over the time horizon of our analysis[17]. We express cost estimates on a net present value basis. We take annual costs over the 10-year duration of the appraisal period and discount these costs to 2021 using the 3.5% social discount rate included in the Treasury Green Book[18].

We include estimates based on the submissions from each supplier in Table 4.1. We provide a more detailed breakdown of cost estimates in Appendix A.3.

Table 4.1: Estimated implementation costs for 'whole of domestic market' based on cost submissions from Suppliers A and B (NPV, £m 2021)

Supplier	0.1% Take-up (£m 2021)	1% take-up (£m 2021)	10% take-up (£m 2021)
Supplier A	*536.4*	*699.3*	*2,331.4*
Supplier B	*85.1*	*314.4*	*2,607.2*

Source: CEPA analysis (based on consultation responses)

The table shows the relevance of fixed and variable costs in defining cost estimates based on take-up. Supplier A estimates higher up-front fixed costs of implementation, even at 0.1% take-up. However, at 10% take-up levels, Supplier B estimates higher costs based on higher estimated variable costs.

✂ [redacted] We provide a more detailed breakdown of cost estimates in Appendix A.3.

Table 4.2: Estimated implementation cost ✂ [redacted] *based on cost submissions from Supplier C (1% take-up scenario only) (NPV £2021/customer)*

Supplier	1% take-up (£/customer 2021)
Supplier C	✂ [redacted]

Source: CEPA analysis (based on consultation responses)

Uncertainty and interpretation

Given the challenges associated with submission of cost estimates, care should be taken in interpreting the estimates of costs presented above. We consider them to be indicative estimates which aim to provide an idea of the order of magnitude of implementation cost. In particular, we note the following:

[17] Drawing on Ofgem's State of the Energy Market 2019 report, we estimated the number of domestic customers in 2021 net of pre-payment meter customers to be 24.2 million. We assumed that the number of customers would grow at the same rate as the general population which we extracted from the Office of National Statistics.

[18] For more detail on the approach taken to estimate net present value costs, see the Treasury Green Book: https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent

- **Uncertainty because of stage of development of P379**: At our stakeholder workshop, the strong consensus was that the P379 modification solution is at the 'Initial Product Definition' phase. Cost estimates are therefore subject to a wide range of uncertainty.
- **Extrapolation to whole of the market**: The numerical estimates that we have received demonstrate the differences in assumed drivers of implementation costs for different suppliers. They also demonstrate differences in relation to economies of scale and the breakdown of implementation costs between one-off and ongoing costs. Our extrapolation approach takes the cost per customer based on the individual submission from each supplier and applies this cost per customer across the whole of the market. In practice, each supplier in the market will have different cost drivers not reflected through this approach.
- **Cost decreases over time**: We have taken annual costs as constant over the 10-year period of analysis. However, in practice, it is likely that suppliers will become more efficient at incorporating these changes and will identify economies of scope with other areas of change in the market over time. It is therefore likely that the annual ongoing cost estimates will reduce over the 10-year period to some extent.
- **Dependence on timing of implementation**: We discussed the interactions between P379 and wider industry change in Section 3.3.2. In particular, we noted interactions with the timing of implementation of MHHS. Some of the suppliers who responded to our consultation identified important dependencies of some cost items on the timing of implementation. In particular, they said that if P379 was implemented ahead of MHHS then they would need to accommodate the costs of introducing the solution within the context of elective half-hourly settlement in which only a proportion of their customers are settled on a half-hourly basis. One respondent suggested that this requirement could lead to certain cost items being significantly higher (more than 20 times as high) as compared to the case in which P379 was implemented after MHHS.

In the following sections, we draw on consultation responses to break down the assessment of each cost item for suppliers in more detail.

4.2. Qualitative assessment of direct costs falling on primary suppliers

We noted some of the challenges that may exist with submitting quantified cost estimates at the current time given some of the outstanding detailed design specification that could have important impacts on implementation requirements and costs. Where numerical estimates could not be provided, we asked stakeholders to provide qualitative assessment of the impacts that implementation of P379 could have on their costs. We summarise the range of cost impacts noted by suppliers in this section.

4.2.1. Cost to serve

Both domestic and non-domestic suppliers identified several ways in which P379 may increase their costs to serve. These included the requirement to revise relationships with supplier agents, managing metering equipment which could be affected by equipment that is the responsibility of the secondary supplier and employing staff members to manage processes which may become more complex where customers have multiple suppliers.

Suppliers cited changes to processes and the potential for additional complexity in relation to:

- developing new tariffs (both for primary and secondary supply);
- managing debt pathways;
- customer service, support and onboarding;
- home moves or changes of tenancy (non-domestic customers);
- disputes relating to billing, erroneous transfers, etc; and

- customer complaints.

Both of the domestic suppliers who submitted justified cost estimates indicated that they expected the additional ongoing costs to serve to scale linearly with the number of customers who adopted secondary supply. This cost item was therefore an important driver of estimated cost increases in our high take-up scenario.

4.2.2. Billing systems

Suppliers stated that billing systems would need to change to recognise a secondary supplier. These changes would need to accommodate new systems to keep track of secondary supplier relationships to allow for accurate reflection of this in billing and the ability to reflect changes to secondary supply energy volumes. Suppliers generally considered these costs to be additional to those required in relation to shared SVA metering arrangements and under Project TERRE given the more limited use-cases of Project Terre, particularly for domestic consumers.

The majority of the cost increases were considered to be one-off costs to revise systems which would need to be incurred regardless of the level of take-up. The ongoing costs were relatively small in comparison. Based on the response that we received, changes to billing systems were considered to be the key driver of cost increase for non-domestic supply and a key driver of additional cost for domestic suppliers.

4.2.3. Settlement systems

As well as billing systems, both domestic and non-domestic suppliers noted that they would need to revise their settlement systems to allow secondary supply to be reflected. For example, this could include adjustments to the settlement reconciliation processes, meter read validations and calculations of gross margins.

Several suppliers noted interactions between the costs of settlement systems and MHHS, both in terms of levels of certainty and magnitude of costs. One supplier indicated significant economies of scope between this and MHHS such that the additional costs of changing settlement systems could fall significantly (more than twenty-fold) if P379 was implemented following MHHS.

As with changes to billing systems, one-off costs accounted for most of cost increases and would be incurred regardless of levels of take-up. Each of the three suppliers who provided numerical estimates identified lower costs associated with settlement systems than for billing systems (around one third of the associated cost).

4.2.4. Other IT systems costs

Some suppliers identified the potential for consequential impacts on other internal IT systems. These included changes to internal settlement, tariff and bill messaging, forecasting and trading systems. However, in many cases, respondents were unable to provide detail on how these may be affected or under what conditions. There also appeared to be some duplication with some of the additional cost considerations included in relation to ‘costs to serve’. These cost items are therefore subject to a high degree of uncertainty and some additional costs may only be realised under certain design specifications.

4.2.5. Volume risk

Most of the supplier responses suggested that managing volume risk could be one of the most significant cost impacts on their business resulting from P379. Many identified the need for this to be reflected in additional risk premia. Stakeholders noted the high degree of uncertainty and lack of transparency of the supply volumes that they would be responsible for given that the secondary supplier was required to only provide their Customer Volume Notifications one hour prior to delivery. Suppliers noted that the level of additional volume risk is proportionate to the number of customers who choose to adopt secondary supply. At take up of 10%, volume risk may become one of the biggest drivers of additional cost for some primary suppliers as is reflected in the cost estimates from one of the domestic suppliers and from the non-domestic supplier who provided cost estimates.

However, we note some divergence from this view. One supplier suggested that they expected to be able to improve their demand forecasting over time to reflect learning from how customers chose to utilise secondary

supply. So long as take up increased gradually over time, they had confidence in being able to adjust their demand forecasting so as to minimise the extent of volume risk to manageable levels which would only result in any increased cost under the high take-up scenario.

4.2.6. Compliance costs

Respondents identified challenges in estimating the impacts on compliance costs without a detailed set of rules and a regulatory framework for primary suppliers in relation to making secondary supply available to customers and in relation to acting as primary supplier to a customer who chooses to adopt secondary supply. Some of the potential implications of secondary supply were considered to be handling of data, ensuring effective communication between primary and secondary suppliers, internal monitoring and audit processes, etc.

While additional compliance costs were not a major contributing factor to the overall cost estimates submitted by suppliers, they were considered to be subject to a high level of uncertainty.

4.2.7. Additional supplier failure risk

Suppliers identified several sources of additional supplier failure risk but noted that the materialisation of many sources of risk would depend on the detailed specification of the solution. In particular, the change in volume risk noted previously was considered by some to be a significant increase in the overall risk of supply. In the case that there was a substantial deviation in secondary supply volumes from that forecast by a primary supplier, and if primary suppliers had been unable to hedge risk to a sufficient degree, an increased risk of supplier failure was identified.

Some suppliers also considered that new entrants into the secondary supply market would generally have a higher risk of failure, partly due to their size and partly due to a higher level of uncertainty in relation to the secondary supplier role and business model.

Even where P379 did not result in additional risk of supplier failure, some respondents noted impacts for the Supplier of Last Resort (SOLR) process in any case. For example, depending on the detailed design, some respondents were concerned that secondary supply arrangements would concentrate SOLR risk onto the primary supplier who was responsible for the customer of a secondary supplier who failed. This is different to the current process for supplier failure in which the costs are spread across the industry.

While acknowledging that secondary supply arrangements would concentrate some of the risk onto particular primary suppliers, we also note that the customers of secondary suppliers are likely to be spread across several primary suppliers. At the same time, it may be reasonable to assume that certain types of customers may be more likely to adopt secondary supply (i.e. those with EVs or heat pumps). These types of customer may be more concentrated towards certain primary suppliers who will in turn take on a greater proportion of risk.

4.2.8. Misuse/mis-selling

Some respondents identified an increased risk of misuse/mis-selling resulting from P379. In particular, some stakeholders noted additional complexity and risk of consumer confusion which may, in turn lead to misuse/mis-selling whether deliberate or accidental. In addition, some suppliers suggested that margins could be squeezed in the presence of multiple supplier options which could increase price pressure and encourage bad practice.

One response suggested that an increase in misuse and mis-selling may be more of a risk in the non-domestic market where there is less regulation of the third-party intermediary and broker market. By introducing an additional sales opportunity for these companies in an area in which the scope for customer confusion may be higher, the concern is that the risk of misuse and mis-selling could increase to a greater degree for non-domestics.

4.2.9. Other costs

Respondents identified several areas of additional risk and the potential for unintended consequences which we discuss in Section 7.

Related to this, some respondents identified the potential for an increase in complex customer queries and which may require close engagement between the customer, the primary supplier and the secondary supplier in order to resolve. Respondents also noted further financial costs in relation to the industry resources needed to engage in the development of the final solution.

4.3. Costs for secondary suppliers

In the above discussion, we have focussed on the direct financial costs which may fall on primary suppliers in order to facilitate secondary supply under P379. We did not receive any consultation responses from suppliers which provided numerical cost estimates for the costs of becoming a secondary supplier. In qualitative responses, those stakeholders who did respond referenced the level of uncertainty in relation to the role of secondary supplier as a challenge for considering cost impacts.

We would expect secondary suppliers to incur costs in relation to many of the cost items for primary suppliers that we have set out above. For example, secondary suppliers would have costs to serve customers and would need to develop billing, settlement and possibly other IT systems. Under P379, secondary suppliers would not face the same volume risk as primary suppliers and costs associated with supplier failure, misuse and mis-selling would depend on the regulatory arrangements in place for secondary supply.

We note that where primary suppliers choose to become secondary suppliers, there may be significant synergies and economies of scope with the changes needed to allow for secondary supply. Some respondents to our consultation emphasised the point that many of the costs that would fall onto secondary consumers to establish business to consumer services would constitute up front fixed costs that duplicate the services already provided by primary suppliers. They suggested that this may introduce inefficiencies in the market which could be passed through to the end consumer.

4.4. Qualitative assessment of direct financial costs falling on other industry parties

In addition to electricity suppliers, we identify the potential for direct financial costs to fall on several non-supplier industry participants. In particular, electricity volume data and settlement processes and systems would need to be revised and industry codes, licences and regulations would need to be updated. We provide more detail on the nature of industry participants that we consider may be affected in Table 3.3.

As well as suppliers, we asked these industry participants to respond to our consultation setting out their views on the additional costs that they may need to incur to implement P379. We asked for numerical estimates where possible. However, as with supplier responses, many of the respondents noted significant challenges in providing accurate numerical estimates. Only two of the 10 non-supplier respondents provided quantified cost estimates.

4.4.1. HHMOAs

We received three responses from stakeholders who operated as HHMOAs. In both cases, the incremental costs of introducing P379 over and above that required for implementation of other areas of change (e.g., P375) was considered to be relatively low. While noting uncertainties in relation to the final specification, anticipated take-up volumes and impacts of MHHS, costs were expected to be negligible at the low end and of the order of £100k of one-off cost per HHMOA at the upper end with ongoing costs of the order of £30k per year per HHMOA.

4.4.2. HHDCs

We received three responses from stakeholders operating as HHDCs. Only two of these responses provided commentary on expected incremental costs to HHDCs. HHDCs noted plans for substantial systems development from 2022, looking ahead to MHHS. They also repeated challenges regarding remaining uncertainties in the detail of the P379 solution.

In this context, the interactions between implementation of P379 and existing plans for development were considered to be a significant determinant of additional costs. Nevertheless, respondents expected that P379 would likely trigger new data flows and processes that would have to be incorporated into HHDC systems. Up-front costs were expected to be [redacted] per HHDC with ongoing annual costs for each HHDC [redacted]

One HHDC noted that costs were more likely to be at the lower end of these estimates under the Option 1 solution but may increase under the Option 2 solution.

4.4.3. HHDAs

We received three responses from HHDAs. One of these responses indicated that there were not likely to be any material cost increases for HHDAs to implement P379. The other response identified no impact under Option 1 and very small costs (£4k per HHDA of one-off costs) under Option 2.

4.4.4. Smart DCC

We did not receive a response to the consultation from the Smart DCC. We would expect some additional costs in relation to ensuring and facilitating the flow of greater volumes of data from Smart Meters. However, in the absence of evidence to suggest otherwise, we do not anticipate that this would be of an order of magnitude to impact significantly on the outcomes of the CBA.

We received a response from the Smart Energy Code Company on P379 which summarises some of the potential risks and unintended consequences for use of smart meters and the smart meter rollout. We summarise these considerations in Section 7.

4.4.5. Licensed distribution system operators (LDSOs)

We received responses from three LDSOs who identified the potential for one-off costs to implement P379 and ongoing costs to maintain and manage new systems and processes. As with other stakeholders, they noted uncertainties in the costs given remaining detail to be developed and noted the dependency of ongoing costs on levels of uptake. As well as MHHS, LDSOs also highlighted interactions between the network charging arrangements for primary and secondary customers and suppliers, and Ofgem's ongoing Access and Forward-Looking Charges SCR.

LDSOs identified the possible need to increase the number of Meter Point Administration Numbers (MPANs), affecting databases as well as the potential need for amendment to flow load processes and systems.

Two LDSOs submitted numerical cost estimates which suggest that one-off costs could be somewhere between £100k and £350k per LDSO while ongoing costs could be between £40k and £200k per year for each LDSO with both cost items relatively independent of take-up. The upper end of ongoing cost estimates incorporates costs of order of £100k per year, assuming an extra meter point registration service (MPRS) environment would be required.

4.4.6. RECCo

We did not receive a response from the RECCo. We would expect some additional costs in relation to developing and maintaining the retail energy code. However, in the absence of evidence to suggest otherwise, we do not anticipate that this would be of an order of magnitude to impact significantly on the outcomes of the CBA.

4.4.7. Elexon

Elexon has developed an internal draft business requirement and indicative cost estimate for its own costs of implementation. Elexon's estimate differs between Option 1 and Option 2 given that under Option 1, central BSC systems are used to perform meter splitting calculations. By decentralising this responsibility under Option 2, the costs of implementation to Elexon are reduced.

Under Option 1, Elexon identifies indicative costs of between £2.7m and £3.2m for delivery of the solution. Under Option 2, these indicative cost estimates fall to between £1.9m and £2.4m. These estimates cover changes anticipated across several of the BSC system agents including the Balancing Mechanism Reporting Service, the SVA Agent, the Legacy Settlement Administration Agent and the Elexon Portal

5. ASSESSMENT OF POTENTIAL BENEFITS

5.1. DESCRIPTION OF USE CASES

Through our review of the literature, including prior work by Elexon and the P379 working group, we identified four potential use cases for P379, which we summarise below:

1. **Arbitrage between primary and secondary supplier options.** Consumers currently have a single supplier that is responsible for their entire load on an ongoing basis. Meter splitting would allow consumers to engage multiple suppliers for certain parts of their load. This may allow them to arbitrage between offers. For example, they could draw on a wholesale market indexed tariff through a secondary supplier when the wholesale price fell below the fixed price tariff unit rates that they had in place with a primary supplier. We identify three separable drivers of potential benefit within this mechanism which we discuss in Section 5.3.

2. **Specialist suppliers, new business models and innovation**. One of the key use cases identified for meter splitting is for suppliers that may only wish to serve part of a customer's load, for example to provide a new service offering. Many different business models could, in theory, be enabled through meter splitting. Our stakeholder engagement suggests that these fall into three broad buckets:
    - **Bundling of electricity with other products.** This would include EV manufacturers also supplying the electricity needed to recharge the EV, and HaaS providers selling heat pumps and the electricity needed to run them as a single product. Under both models, the EV manufacturer and HaaS provider may only want to supply the electricity needed for the EV or heat pump, and not the rest of a customer's electricity load.
    - **Specialist suppliers offering flexibility services.** Under this model, a specialist secondary supplier would be able to connect and control smart devices within a customer's premises to provide flexibility services to balance the electricity system. As an example, they would be able to stop EVs from being charged during periods where there is congestion on the local network or when there is insufficient generation capacity to meet demand. Again, for meter splitting to have benefit, this assumes that the supplier would specialise in providing this service for the grid and would only be interested in serving the part of a customer's load that could be used for such services (e.g., EVs, heat-pumps, batteries etc.).
    - **Different customers for different parts of the load.** These refer to models where there may be a different customer for different parts of the load behind a meter. For example, a firm purchasing a company EV for their employee may also want to pay for charging the EV at the employee's home. Alternatively, meter splitting could be used in multi-occupancy homes to split bills between different occupiers.

3. **Increased penetration of community energy.** Community energy can refer to a wide range of energy projects involving local communities. In the context of P379, we are referring to local electricity generation projects where the customers for the local generation are also locally based. Under such a model, a customer would be able to use one supplier linked to their local generation project (most likely the secondary supplier), and another supplier for any demand that will not be served through local generation.

4. **Enabling additional uptake of peer-to-peer trading**. Under this model a secondary supplier could, through meter splitting, enable the trading of electricity between local producers and local consumers. Such a supplier would specialise in peer-to-peer trading, whereas the other supplier would serve the part of a customer's load that is not supplied through local producers.

5.2. Summary of benefits

Table 5.1 summarises our assessment of the potential benefit associated with each use case. We summarise the likelihood with which we anticipate some material benefit to be delivered, the expected maximum possible scale of benefit and the time horizon for benefit. By short-term we mean in the first one or two years of the appraisal period. By medium-term we mean between 5-10 years into the appraisal period and by long-term we mean beyond the appraisal period.

Table 5.1: Summary of benefits

Use case	Likelihood of some benefit	Maximum scale of possible benefit	Timescale of benefit
Consumer price arbitrage	Low-Medium	Low-Medium (of welfare benefit)	Medium-term
Specialist suppliers and bundling	Medium-High	Medium	Medium-term
Community energy	Low-Medium	Low-Medium	Short-term
Peer-to-peer trading	Low	Low	Long-term

5.3. Consumer price arbitrage between wholesale indexed and fixed tariffs

Consumers currently engage a single supplier to be responsible for their entire load at any given supply point. Through meter splitting, consumers could engage multiple suppliers and opportunistically choose the supply option that is cheapest at any point in time. They could temporarily nominate their entire load or some portion of it to a secondary supplier who can provide a cheaper price for electricity in those periods. In this way, consumers could benefit from transient price differences between tariffs from a primary supplier and secondary supplier, even without any change to the timing of their consumption.

For our analysis we assume that:

- Customers choose a primary supplier with a hedged tariff. I.e., the supplier forecasts the load that they expect to serve in the upcoming season and purchase hedging contracts to cover the expected volume and shape. They then offer fixed price retail tariffs where the wholesale component of the tariff reflects the average price of the hedging contracts that they have entered into.
- Customers choose a secondary supplier with a time of use, wholesale indexed tariff. Secondary suppliers offer tariffs that are indexed to wholesale, day-ahead prices. They are thereby not directly exposed to wholesale price risk and do not buy any hedging contracts.

We note that customers could simply choose to accept a wholesale indexed tariff from a single supplier without the need for multiple supply; although that would require them to face the indexed tariff for all, rather than part of their load, and at all times. To this end, the benefit of multiple suppliers is only through the potential for greater uptake of such offers and the ability to arbitrage onto the fixed price offer where lower than the wholesale price. We consider there to be three separate mechanisms for benefit within this use case:

1. **Avoided risk premium**

When a consumer opportunistically switches load between a primary and secondary supplier, they capture the full price difference between the fixed price and the day-ahead price. We consider that part of this benefit comes from avoiding a risk premium which is built into the fixed offer price to reflect the risk that generators face in selling the contract and to reflect primary supplier forecasting imperfections in load shape, customer numbers and weather expectations. Consumers accepting wholesale prices effectively take on the hedging risk that would otherwise have been managed by the primary supplier. Therefore, this is only likely to represent a legitimate benefit for consumers

who are happy to accept and manage this risk for some of their load, without experiencing offsetting costs or reduced utility.

2. **Distributional transfer**

We also consider that price arbitrage represents an imperfect transfer of risk since primary suppliers are not expected to know the timing or volume of load which is opportunistically switched to secondary suppliers. Without this information, primary supplier hedging is likely to be less effective. Suppliers are more likely to be over hedged and thereby more expensive per unit of electricity sold (or, less profitable if the primary supplier is unable to recover the additional expense). To the extent that these costs are socialised across all primary supplier customers, or absorbed by the supplier through reduced profitability, part of the effect of consumers arbitraging between fixed and wholesale indexed prices will represent a distribution impact rather than a genuine welfare benefit.

3. **Enhanced load shifting incentives**

A further benefit is possible if secondary supply opportunities increase the propensity for consumers to agree to tariffs indexed to wholesale prices via secondary suppliers and, in turn, to increases in the extent of load shifting between different time periods. Using dynamic technologies to shift load in response to wholesale prices can produce a benefit for the consumer undertaking the shifting as well as a system-wide benefit from 'peak shaving', i.e., leading to lower wholesale prices and lower costs from reduced network stress.

5.3.1. Analytical approach

Assumptions

We have carried out high-level modelling to establish an upper estimate of the possible benefit that could be associated with this use case. Our analysis relies on several assumptions and should be considered as an indicative assessment to establish an 'order of magnitude' of potential benefit. Assumptions include the following:

- We have assumed that consumers can capture the full price difference between fixed and day-ahead prices, whereas in practice some of this value could be retained by secondary suppliers to cover their costs and margin.[19]
- We have assumed that the volatility of day-ahead prices during the modelling period is equivalent to that observed historically over the past five years.
- We have assumed that this supply arrangement would be most appealing to consumers with large, separable load which can easily be predicted and controlled (e.g., EVs, heat pumps, batteries). From a consumer perspective, this could happen if a consumer adopts meter splitting at the same time as purchasing one of these technologies. From a secondary supplier perspective, there may also be a preference for EVs, heat pumps and batteries as their consumption can be controlled – directly, or through dynamic tariffs – to manage balancing market risk.
    - **For consumers with EVs and heat-pumps:** Opportunistically switching load between a fixed electricity price provided by a primary supplier and the day-ahead price facilitated by a secondary supplier, depending on which is cheaper at any point in time.
    - **For consumers with energy storage:** Arbitraging intra-day differentials in day-ahead prices (i.e., charging overnight and exporting during the morning or evening peak). Our analysis captures the part of the load shifting benefit that accrues to consumers, but not any potential system-wide benefit.

[19] We discuss secondary supplier costs in section 5.2.10 but have not quantified them for this impact assessment.

- We have assumed that network charges and any costs associated with environmental or social schemes are unchanged; the modelled benefit does not rely on a cost base disparity between primary and secondary suppliers in any of these categories.

Analytical steps

Our model uses the CT scenario within National Grid's Future Energy Scenarios to establish levels of uptake of EVs, heat pumps and residential batteries. To these annual volumes of EVs and heat pumps we apply usage profiles derived from empirical studies[20] to construct hourly usage profiles for each technology which span the 10-year modelling period (i.e., 2023 to 2032, inclusive). There is no usage profile for residential batteries. Instead, we assume that the full storage volume is cycled once every day.

We have assigned a value to the arbitrage opportunities for each technology by analysing historical day-ahead prices and historical hedging contract prices for the past five years.[21] For EVs and heat pumps we have determined what the primary supplier's fixed price would have been by using the method employed by Ofgem in its Default Price Cap analysis.[22] Specifically, we assume that:

- the fixed price for any season reflects the average price of wholesale contracts available in the six months commencing eight months prior to the start of the season; and
- suppliers hedge 70 per cent of their load with baseload products and the remaining 30 per cent with peak load products (i.e., covering the period 07:00 to 19:00 on weekdays).

For a five-year period, we compared the prevailing fixed price with hourly day-ahead prices and observed the differences between them. We assume that a consumer will be charged the fixed price for their consumption unless they choose to opportunistically switch their load to a secondary supplier and pay the day-ahead price instead. In the model, the consumer can benefit by making this switch when the day-ahead price is less than the fixed price. We have calculated the benefit as the difference between the fixed price and day-ahead price when the latter was lower than the former. Taking all periods in which there was a benefit, we calculated monthly averages of the benefit for each hour of the day.

For residential batteries, we assumed that a battery with two hours of storage and 90 per cent round-trip efficiency is cycled once every day. This operational regime was applied to day-ahead prices from the past five years, assuming that the battery was charged for the cheapest two hours of the day and discharged in the most expensive periods, subject to the battery having to be at least partially charged before it can be discharged. This analysis produced daily arbitrage values which we then averaged to produce monthly averages of the daily benefit.

We matched the hourly technology usage profiles with the arbitrage values for EVs and heat pumps and multiplied the battery arbitrage values by the by projected residential battery volumes, to produce a benefit for every hour of the 10-year modelling period. We then summed these hourly benefit values to produce annual totals and a total discounted benefit.

This approach generates indicative estimates of the overall benefit associated with arbitrage based on the combination of risk premium avoidance and distributional benefits discussed previously. To provide an indication of the breakdown between these two mechanisms, we have estimated the value of the risk premium using historical pricing data. We define the risk premium as the difference between the fixed price that a hedged supplier would incur for wholesale market purchases and the average wholesale price during the corresponding delivery period of

[20] National Grid ESO, Development of GB electric vehicle charging profiles and Customer-Led Network Revolution, Enhanced profiling of domestic customers with air source heat pumps.

[21] Day-ahead prices from ENTSO-E Transparency Platform and hedging contract prices from Bloomberg (ELUBS and ELUPS Indices) for the period 1 October 2015 to 29 September 2020.

[22] Ofgem, Default Tariff Cap: Decision, Appendix 4 – Wholesale costs, 6 November 2018.

the hedging contracts. We calculate an indicative risk premium from five years of wholesale price and hedging contract data by subtracting the average day-ahead price from the average primary supplier fixed price. We identify an approximate supplier risk premium of £5.03 per MWh.

5.3.2. Magnitude of potential benefit

We present the results of our high-level modelling in Table 5.2 based on the assumptions set out above. We set out the full modelled benefit as well as our estimate of the proportion of this that constitutes risk premium avoidance as opposed to the distributional impacts discussed previously.

When scaled by the volume of energy consumed by EVs and heat pumps in our analysis, we find that the risk premium is approximately 39 per cent of the total benefit possible through the arbitrage opportunities. Hence, we estimate that around 61 per cent of the modelled benefit is a transfer rather than a welfare enhancement. We emphasise that this breakdown is based on several high-level assumptions and should be considered indicative only.

For each uptake scenario we provide a range for the benefit where the bounds reflect the possible outcomes in terms of the distribution of EVs, heat pumps and residential batteries, reflecting uncertainty the number of unique households from the EV, heat pump and battery cohorts.

- The lower bound assumes that households have either an EV, heat pump, battery, or no technology, and there is no overlap between these groups.
- The upper bound assumes that the technology groups are entirely overlapping (i.e., the number of households that have any technologies is capped at the volume of the most popular technology).

Table 5.2: Total potential benefit from increased competition for supplier volumes over 10-year timeframe of analysis (NPV, discounted to £m 2021)

Uptake scenario	Potential total benefit ('risk premium' and distributional) (£m 2021)	Potential 'risk premium' benefit (£m 2021)
0.1%	7.4 – 11.7	2.9 – 4.6
1%	73.8 – 116.5	29.1 – 46.0
10%	732.3 – 1,070.9	289.3 – 423.0

Source: CEPA analysis

5.3.3. Likelihood of potential benefit

P379 was raised to alleviate a regulatory barrier to competition for energy volumes behind the customer meter. We consider it possible that removing this barrier may allow for the nature of arbitrage between multiple supplier tariffs that we set out above. However, it is less clear to us that there would be a material net benefit from arbitrage between primary and secondary supplier offers.

We note that much of the benefit of arbitrage that we have modelled could be established simply by signing up to a wholesale indexed tariff with a single primary supplier, particularly as these offers become increasingly sophisticated. In particular, this would deliver much of the 'risk premium' avoidance benefit identified above, but with less likelihood of a distributional transfer from primary to secondary supplier customers. Wholesale indexed tariffs are emerging in the market[23] and becoming more sophisticated, including through partnerships between suppliers and technology companies that allow load profiles to be better predicted and modelled. This can also help to deliver much of the load shifting benefit that we set out but did not model.

[23] See the Octopus Agile Tariff for example: https://octopus.energy/agile/

We note the potential for some of the benefit associated with arbitrage to be eroded by the response of primary suppliers to the presence of secondary suppliers. In consultation responses, some suppliers indicated that they would seek to move customers who engage secondary suppliers onto amended supply tariffs to ensure that they could still recover their fixed costs and manage volume risk more effectively. Tariff rebalancing between the fixed and variable components of supply tariffs could detract from the modelled benefit, but we have not attempted to quantify this. Volume risk is a quantified cost reflected in Section 4.1 of this report and therefore captured in the overall assessment of benefits and costs.

Some respondents also indicated that some of the benefits associated the arbitrage use case are dependent on inequalities between the regulatory arrangements for primary and secondary suppliers. The modelled benefits that we observe could also be affected by regulatory changes to address distributional impacts if regulators find that such impacts are inequitable and distortionary to effective competition.

5.3.4. Timescale for delivery of potential benefit

To the extent that benefit does materialise, this is likely to be driven by the increasing propensity for take-up of wholesale indexed tariffs, primarily by those who adopt EVs, heat pumps and batteries. For that reason, we would expect the bulk of any benefit to materialise over the medium term, in the second half of the appraisal period (i.e., between 2028 and 2033).

5.3.5. Uncertainty

Table 5.3 sets out the key sources of uncertainty in relation to this use case and what this means for the range of potential benefit.

Table 5.3: Sources of uncertainty for enhanced competition for consumer volumes benefit

Source of uncertainty	Potential impact on benefit
Potential for 'peak shaving' leading to lower wholesale prices and reduced network stress	The option of retaining a fixed tariff with one supplier while agreeing to a wholesale indexed tariff with another could increase the propensity for take-up of wholesale-indexed tariffs and may encourage some additional level of load shifting. This could lead to additional system benefits including 'peak shaving' leading to lower wholesale prices and savings from reduced stress on network assets. This could result in a higher benefit than those that we have quantified. However, there are other ways in which consumers can gain access to wholesale prices for their flexible resources, making it unclear to what extent significant benefit could be attributed to meter splitting.
Extent to which modelled benefit is welfare enhancing	We noted above that the modelled benefit consists of a benefit from avoiding the primary supplier risk premium as well as some amount that is a transfer from primary suppliers to consumers. Our *indicative* estimate of the split is 36:64 between risk premium benefit and transfer. In addition, the actual split could change over time Beyond this there is further uncertainty in the extent to which the avoided risk premium is a benefit for consumers. The risk does not disappear but comes out of the retail price because the consumer is managing it themselves. Our estimates assume that there are not costs or disbenefit from consumers doing this whereas in practice there may be some loss of utility in managing additional risk that was previously performed by the supplier.
Secondary supplier costs and margin	We would expect secondary suppliers to take on some level of cost and risk that we have not accounted for. Neither have we incorporate a margin into the wholesale market indexed price of secondary suppliers. Were these to be included then the benefit seen by consumers would be lower than in Table 5.2.

Magnitude of uncertainty

We believe that the uncertainties around the extent to which the modelled benefit is welfare enhancing and secondary supplier costs and margin could be material. Both suggest a lower benefit than the one we have modelled. For this reason, we consider our analysis to represent an upper estimate.

5.4. Specialist suppliers, new business models and innovation

One of the key use cases frequently associated with meter splitting, and secondary supply more broadly, is the idea that it would enable a range of innovative business models where firms are responsible for supplying only part of a customer's load. Such firms may not consider themselves electricity suppliers but may require access to a customer's load to provide another service.

The first broad bucket of business models is the idea of bundling electricity supply with another product or service. In Figure 5.1 we explore two bundling models, one for electrified transport and one for electrified heat. The bundling model for EVs is much more developed, with certain bundled tariffs already in the market.[24]

Figure 5.1: Bundled electricity supply propositions related to transport and heating

Bundled EV charging

Electricity for charging an EV is bundled with the EV itself or with a smart home charger. For example:

- A new EV purchase may come with a free mileage allowance
- A smart home charger comes with free mileage when recharged at certain times of the day
- A monthly subscription bundles together an EV lease, home charging, and mileage.

Heat as a Service

Consumers purchase heat rather than energy, with the heat source, energy, and energy optimisation and efficiency services all bundled together in a single product.

For example, a firm with a HaaS offering may provide a heat pump, associated electricity, a smart thermostat, and any necessary insulation, all as a single service.

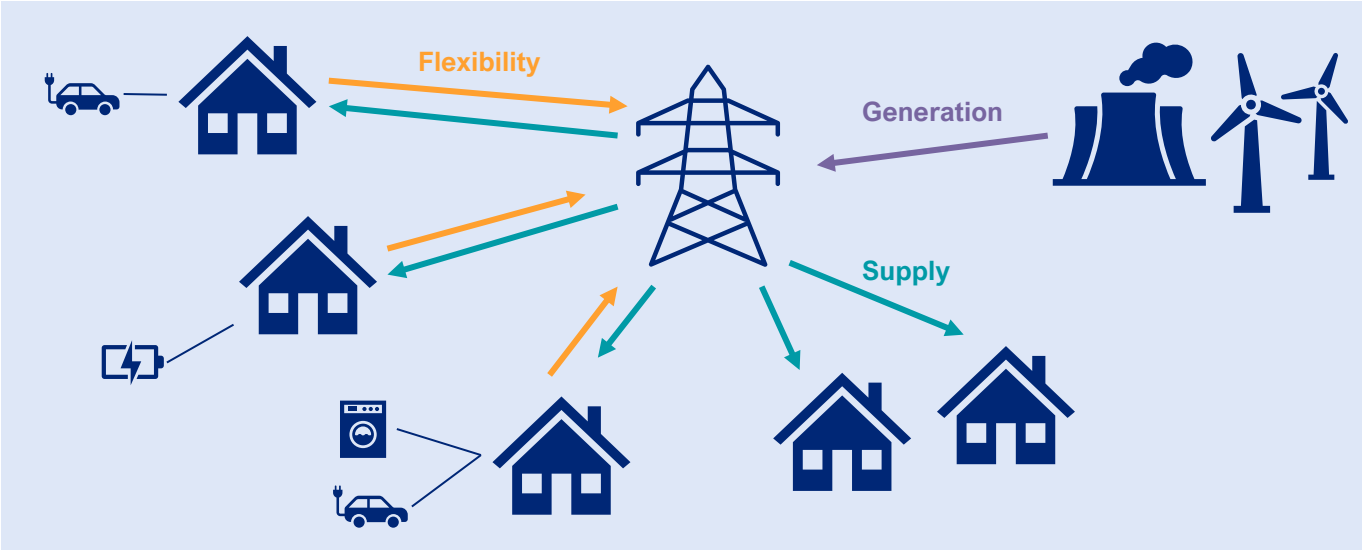
Source: CEPA

With bundling, the hypothesis we are testing is that meter splitting would provide a route to market for firms wishing to provide bundled services by allowing them to supply only a subset of a customer's load, i.e., demand from EV charging or heat pumps. Specifically, we are testing whether without P379, the uptake of these business models would be limited because alternate routes to market do not exist.

The second broad bucket of business models is the use of secondary supply to get access to the part of a customer's load that is more flexible, to provide flexibility services to the energy system. Under such a model, shown diagrammatically in Figure 5.2, secondary suppliers would act as aggregators being responsible for, and having control over, assets within a customer's home or premises that are flexible. This could include EVs, heat pumps or other forms of electric heat, and batteries. The aggregators would then be able to use these assets to shift load away from the peak, provide balancing services for the transmission network, or provide flexibility services for the local grid.

[24] Current News (2020) Octopus partners EO Charging for EV charging solution. Available at https://www.current-news.co.uk/news/octopus-partners-eo-charging-for-ev-charging-solution

Figure 5.2: Model of flexibility services provided by consumers



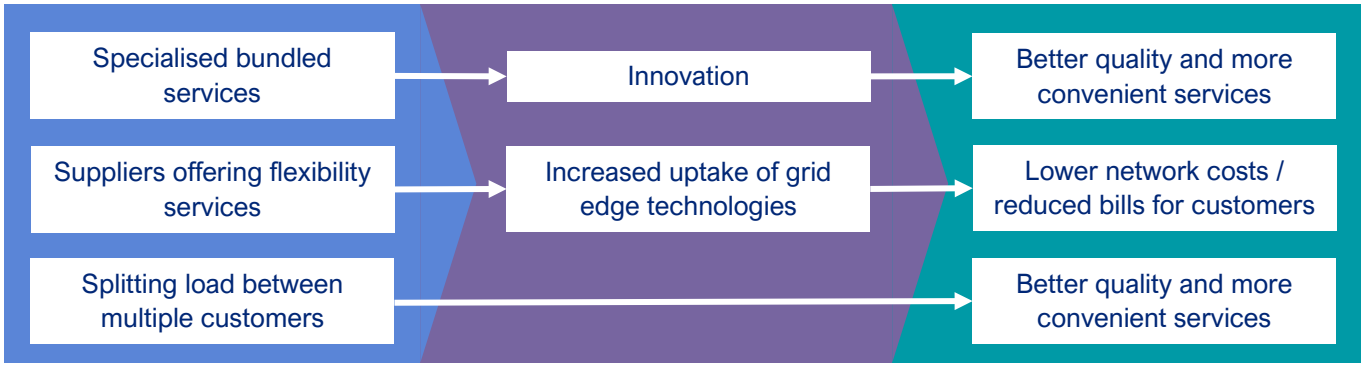
Source: CEPA

Similar to bundling, we are testing the hypothesis that without P379, the ability of firms to provide aggregator services would be limited. As part of this, we are considering the specific barriers that prevent firms from being able to access the flexible part of a customer's load, and whether alternate routes to market exist.

The third broad category of new business models is where different parts of the load behind a boundary meter have different customers. Here, we have explored whether there are other applications where it may be beneficial for there to be different paying customers for different parts of a premise's electricity consumption, beyond the two outlined above. In our stakeholder engagement, other examples provided included allowing corporate customers to have one supplier for their internal use and have a second supplier for visitor usage.

Figure 5.3 outlines the main benefits we expect to see with all three business models. The creation of bundled offerings may, through innovation, provide services that customers value and are willing to pay for. This could be because they perceive the quality of the services they are being offered to be better, or because it is more convenient. Similarly, business models that allow for the splitting of the load behind a boundary meter to different customers, may provide a more convenient solution than alternatives. For example, an automated solution for firms to pay for their employee's domestic EV charging, may be more convenient than the employee making manual expense claims. Finally, greater usage of suppliers offering flexibility services would in turn increase the uptake of grid edge technologies such as smart devices and EVs, improving the efficiency of the electricity system and in turn lowering network costs and reducing customer bills.

Figure 5.3: Map of potential benefits from the introduction of specialist services, tariffs and business models



5.4.1. Barriers alleviated by P379

Without P379, a firm wishing to be responsible for supplying part of a customer's load for these new business models, would be required to put in place a second meter at the boundary point. For domestic customers and small commercial customers, the cost and effort involved in putting in place a second boundary meter would likely outweigh the benefits, with the cost of procuring and installing a second boundary meter estimated at £500 in current prices.[25] This does not include additional costs of installing a new network connection and connecting the meter to the power supply[26]. P379 should, in theory, alleviate this barrier by allowing for secondary supply without needing a second meter. This could reduce the costs involved in getting a secondary supplier, making it more accessible and increasing uptake.

Many of the suppliers we spoke to agreed that the cost of a second boundary meter would be impractical for most domestic users and, therefore, there was a material barrier that could be alleviated through P379. However, one supplier we spoke to considered that a second meter at the boundary point would be an easier and more effective approach for non-domestic users. They noted that premises with large-scale on-site generation already had separate import and export meters.

Additionally, through our stakeholder engagement, we found other potential routes to market for these business models that did not rely on meter splitting:

- **Partnering with energy suppliers** – We explored opportunities for bundling with a stakeholders in the HaaS space. These stakeholders stated, although they would not rule out direct energy supply, partnering up with existing energy suppliers would be their preferred strategy. The main motivation for this was to allow each firm to focus on their relative strengths. Many industry stakeholders concurred with this view, suggesting that low margins and up-front fixed costs within the energy supply business would make entry an unattractive proposition for firms outside the sector.

  A similar argument has been raised in the context of the provision of flexibility services, with stakeholders highlighting existing partnerships between aggregators and suppliers.[27] More broadly, we note that there are several emerging partnerships between energy suppliers and vendors of behind the meter devices ranging from digital assistants, home energy management systems, EV charging, and electric heating.[28]

- **Existing energy supplier providing demand-side flexibility services** – Many supplier stakeholders considered that flexibility services could be provided effectively under the single supplier model, particularly following P375. They questioned how much additional value secondary suppliers would be able to provide in this regard. An opposing view was taken by other industry participants, who suggested that many existing suppliers were insufficiently agile and faced insufficient competitive pressure to offer such services to consumers. They suggested that the competitive pressure created by new market entrants through meter splitting, would accelerate the development of services and tariffs that allow consumers to provide flexibility services to the grid.

- **'Fuel card' type arrangements for charging EVs in multiple locations** – One of the business models we refer to earlier is using secondary supply for non-domestic consumers to pay for EV charging at their

[25] DECC (2011) Impact Assessment: Provision of third-party access to licence exempt electricity and gas networks. Available at https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/43255/1155-ia-third-party-access-licence-exemptions.pdf

[26] E.g. see: https://www.westernpower.co.uk/downloads-view-reciteme/212686

[27] Automotive World (2021) ev.energy and Flexitricity partnership helps suppliers unlock Balancing Mechanism with smart EV charging. Available at https://www.automotiveworld.com/news-releases/ev-energy-and-flexitricity-partnership-helps-suppliers-unlock-balancing-mechanism-with-smart-ev-charging/

[28] IGov New Thinking for Energy (2019) Changing actor dynamics and emerging value propositions in the UK electricity retail market. Available at https://projects.exeter.ac.uk/igov/wp-content/uploads/2019/01/IGov-BM-Analysis-report.pdf

employee's homes. One stakeholder, in their consultation response, argued that this type of arrangement could be accommodated more easily and cheaply, through a fuel card style arrangement. They argued that this would also be more flexible, allowing employees to charge EVs at any location rather than being restricted to the workplace or home. They also indicated that this would be much easier to implement than the industry change required under P379.

In our stakeholder engagement, the feedback we received was that there were more fundamental barriers to widespread adoption of many of these business models, including the need for MHHS and further development of the market for flexibility services.

We have explored potential innovations that have previously been discussed, or that we or others have considered feasible under meter splitting. However, a key feature of innovation is that it is generally not easy to predict. There may be other innovations not currently anticipated that may only materialise once meter splitting is implemented, and once firms inside and outside the sector explore the possibilities created through the opening of behind the meter competition.

5.4.2. Magnitude of potential benefit

We expect the magnitude of potential benefit from specialist suppliers to increase linearly with uptake scenarios for bundled services and split loads between multiple customers. However, the benefit from flexibility services may increase exponentially with greater uptake, with increased penetration allowing for more learning, which in turn allows for lower costs and a greater ability to extract flexibility from a customer's load.[29]

The potential value to an individual customer from bundled services or other products that offer greater convenience is unclear. We are not aware of any studies that have explored the value to a customer from such services,[30] nor explored what the likely uptake of such services would be at different price points. We do know that there have been several bundled offerings around EV charging introduced into the market over the past 18 months, suggesting that there is at least some demand for bundled services.[31]

On the other hand, there has been much more consideration of the potential value of flexibility services. Analysis has suggested that the energy bills of customers with flexibility may be up to 70% lower than for customers without flexibility,[32] though other studies have estimated the reduction to be closer to 25%.[33][34] Taking 2019 average electricity bills as an illustration, this would imply a benefit per domestic customer of up to £475 per annum.

This suggests that the potential benefit from greater uptake of flexibility services could be substantial, and there is likely to be some benefit from bundled services. However, as we show in other sections, many of these benefits are likely to materialise even in the absence of P379, and in some instances are already materialising. Consequently,

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[29] BEIS (2015) Realising the potential of demand-side response to 2025. Available at https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/657144/DSR_Summary_Report.pdf

[30] There have been some studies undertaken in a non-UK context, where it is unclear the extent to which the conclusions would be applicable to UK consumers. For example, Lee and Won (2018) find that Korean consumers are unlikely to value bundled services. Lee, Y-S and Won DH (2018) An Empirical Study on the Consumer Value of the Bundle Services in the Electricity Market. Available at https://www.koreascience.or.kr/article/JAKO201826259708412.page

[31] AM Online (2020) Mitsubishi offers free electricity to Outlander PHEV buyers. Available at https://www.am-online.com/news/manufacturer/2020/02/04/mitsubishi-offers-free-electricity-to-outlander-phev-buyers

[32] Strbac (2012) Cost effective evolution to a Low Carbon Future: Role and Value of Demand Side Response. Available at https://www.ofgem.gov.uk/ofgem-publications/56991/goran-strbac-presentation-demand-side-response-event-autumn-2012-pdf

[33] Imperial College London (2014) Residential consumer responsiveness to time-varying pricing. Available at https://innovation.ukpowernetworks.co.uk/wp-content/uploads/2019/05/A3-Residential-Consumer-Responsiveness-to-Time-varying-Pricing.pdf

[34] We also note that reforms to network charging structures may impact on the magnitude of these benefits.

we consider the scale of benefit from specialist services and bundling as a result of P379, is likely to be more limited.

5.4.3. Likelihood of benefit

The consensus from stakeholders we engaged with was that the biggest opportunities from P379 are likely to relate to the provision of bundled services or demand-side flexibility services. Meter splitting would allow a new route to market for firms who are not existing suppliers but wish to provide a niche offering. It may also enhance flexibility and optionality for consumers by allowing them to purchase multiple different bundled products from different providers[35]. Although we have shown in other sections that such opportunities could and are arising without P379, it is likely that at least some innovation would emerge given multiple supplier opportunities that would not do otherwise. This could happen either through P379 enhancing the pace of uptake of these new services through supporting consumer appetite, or by P379 enabling entry of firms who do not wish to partner with an existing supplier but want to only provide volume to certain loads within the household.

5.4.4. Timescale for delivering benefits

The demand for specialist services and business models depends substantially on consumers having assets that are flexible or assets where consumers may value bundled services; primarily heat pumps and EVs. As such, the timescale for any benefits materialising under this use case largely follows that for the uptake of EVs and heat pumps. By 2033, National Grid expects there to be 19 million EVs and 7.8 million heat pumps under its CT scenario, with each group providing approximately 1 GW of electricity flexibility.[36]

Based on these timescales, we consider it plausible that some of the benefit associated with take-up of these technologies and meter splitting will materialise within the appraisal period. Take-up of EVs and heat pumps is skewed towards the latter half of the appraisal period and bundled services are not in the immediate planning horizon for the EV and HaaS firms we spoke to. We therefore expect that the majority of any benefit would be delivered in the second half of the period.

5.4.5. Uncertainty

Table 5.4 sets out the key sources of uncertainty in relation to this use case and what this means for the range of potential benefit.

[35] For example, purchasing a Nissan car with a bundled package from one supplier and a Tesla car with a bundled package from a different supplier.

[36] National Grid (2020) Future Energy Scenarios. Available at https://www.nationalgrideso.com/document/174541/download

Table 5.4: Assessment of uncertainty around benefits from specialist services, and new and innovative business models

Source of uncertainty	Assessment of magnitude and potential impact on benefit
Consumer appetite for new business models	The consumer appetite for many of the potential business models we have explored is highly uncertain. Although they have been studies that have considered consumer appetite for multiple suppliers, and have found that many are receptive to this,[37] there has been limited testing on whether uptake of these business models would likely remain niche or become widespread. Some studies have looked at specific aspects of consumer appetite. For example, dynamic time of use tariffs would allow consumers to extract the maximum value from flexibility. Research into consumer views on such tariffs suggests there is not a large appetite for them, with consumers worried about complexity and unpredictability of tariffs.[38] However, meter splitting may encourage greater innovation in the automation of such flexibility, allowing customers to take advantage of dynamic tariffs without any manual input and without worrying about excessive prices for uncontrollable loads. If consumer appetite for these new business models is lower than we anticipate in previous sections, the scale of benefit is likely to be substantially lower.
Consumer and producer value from bundled services	Bundled services could deliver benefit by creating consumer value (i.e., providing greater convenience to customers such that they are willing to pay more for the bundled service) or by creating producer value (i.e., lowering costs for bundled suppliers through greater competition of through economies of scope). As these bundled services are relatively new to the market or are yet to be introduced, it is yet unclear whether such services create either consumer or producer value and what the scale of the value is. Nevertheless, we have not been able to find concrete examples of efficiencies or economies of scope that could arise through bundling and, therefore, we consider the scale of the benefit likely to be small.

5.5. Increased penetration of community energy

Another potential use case for P379, is to provide consumers with another way of accessing generation from community energy schemes. Many community energy organisations would like locally owned generators to be able to supply electricity directly to local households and businesses, partly to keep value within the local community and to support local community development.[39] This is hindered somewhat by the *Supplier Hub* model that requires consumers to purchase their electricity through a single supplier intermediary.[40]

Under the current model, a local, community-owned generator wishing to sell electricity to local consumers would need to form a partnership with a licensed supplier and agree to either a white label, licence lite or sleeving arrangement.

[37] Watson et al. (2020) Two energy suppliers are better than one: Survey experiments on consumer engagement with local energy in GB. Available at https://www.sciencedirect.com/science/article/abs/pii/S0301421520306066

[38] Impact (2019) Future Energy Models: Research findings report. Prepared for Citizens Advice. Available at https://www.citizensadvice.org.uk/Global/CitizensAdvice/Energy/915%20Citizens%20Advice%20Future%20Energy%20Models%20Report%20Final%20v2.pdf

[39] Regen (2015) Local supply: Options for selling your energy locally, 3rd Edition. Available at https://www.stephens-scown.co.uk/app/uploads/2015/07/LocalEnergySupply.pdf

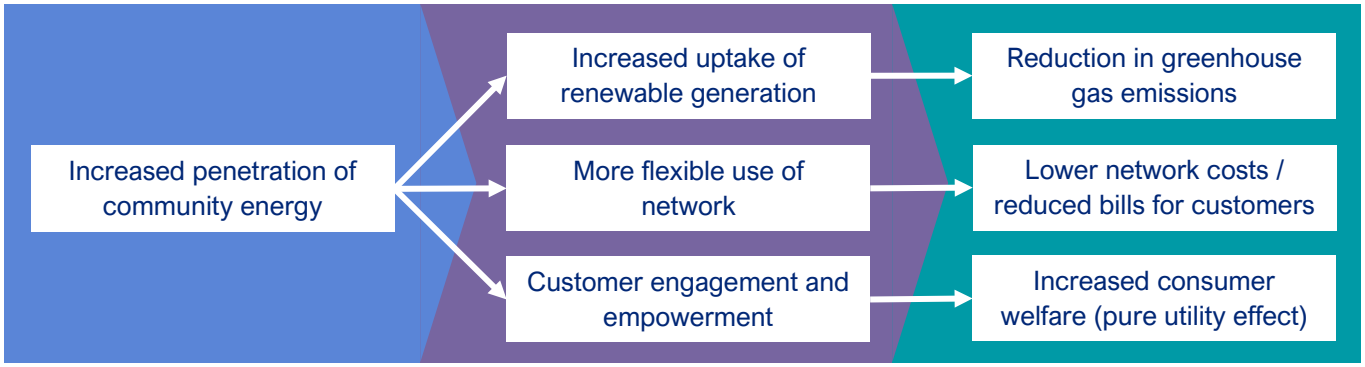
[40] Green Alliance (2019) Community energy 2.0 The future role of local energy ownership in the UK. Available at https://www.green-alliance.org.uk/resources/Community_Energy_2.0.pdf

- A **white label** supplier works in partnership with an existing licensed supplier who provides back office functions, metering etc. while the white label supplier is responsible for customer acquisition, determining tariffs, and branding. The licensed supplier would then purchase the local community generation on behalf of the white label supplier.
- A **licence lite** allows small generators to become suppliers. It operates in a similar manner to a white label arrangement but with the licence lite supplier also being responsible for meeting industry codes.
- A **sleeving** arrangement is a type of Power Purchase Agreement between local generators and suppliers where local consumption is netted off against local generation.

With all of these arrangements, local consumers wishing to purchase from local generators need to switch to whichever supplier forms a partnership with the local generator. The hypothesis we are testing is that the requirement to switch is a barrier to local consumers purchasing electricity from community-owned generators, which in turn acts as a barrier to the development of community generation.

If this hypothesis is true, the consequential benefits from removing this barrier is as shown in Figure 5.4.

Figure 5.4: Map of benefits from increased penetration of community energy



5.5.1. Barriers alleviated by P379

P379 has been identified in the literature as a potential enabler for community energy and specifically, for local supply.[41] In addition, the code modification was originally proposed by a community energy organisation. However, many of the papers and studies we have reviewed do not identify or articulate the specific barriers to community energy that would be alleviated by P379.

The main barrier we have identified that P379 would help to alleviate is the requirement for consumers to switch to a single shared supplier should they wish to purchase electricity from a community-owned generator. This may lead to hesitation on a customer's part to switch due to perceived inconvenience or risk, or it may be that the tariffs on offer for the part of a customer's load that is not served by local supply, are unattractive. Such requirements may also lessen competition between suppliers in areas with community-owned generation assets.

We explored these issues with stakeholders actively participating in community energy, asking whether they considered this requirement to be a material barrier. The broad consensus was that this requirement was not the biggest barrier to the uptake of community energy, or to local generators supplying local consumers directly. Some stakeholders with experience with sleeving arrangements did not experience any challenges with customers switching to a shared supplier.

All of the community energy stakeholders we spoke with suggested there were other, more fundamental barriers, to community energy. Most notably, they considered that the centralised electricity system and the network charging

[41] See, for example, http://www.edinbanecommunitycompany.org/Downloads/Edinbane%20Local%20Energy%20Study.pdf and https://es.catapult.org.uk/wp-content/uploads/2020/11/Local-Energy-Markets-review.pdf

regime insufficiently valued decentralised energy resources, and regulations and licensing obligations such as the universal service obligation, prevented the creation of local energy markets.

Where stakeholders disagreed, was whether P379 would act as a small step towards more fundamental reform or might reduce the focus on more material change. One stakeholder we spoke with suggested that P379 failed to tackle the fundamental issues that prevented greater penetration of community energy and would act as a further barrier by increasing supplier costs. On the other hand, another community energy stakeholder suggested that meter splitting, if implemented correctly, would create competitive and regulatory pressure for more substantial reform.

5.5.2. Magnitude and likelihood of potential benefit

There is significant potential for the development of community energy over the appraisal period, with WPI Economics estimating that in a baseline scenario, installed generation capacity could rise from approximately 240 MW in 2018 to 320 MW by 2024 and 418 MW by 2030. Under a more supportive policy environment this could rise to 3,000 MW by 2030 and in the most ambitious scenario, to 5,720 MW by 2030.[42] This suggests that if P379 was to act as a real enabler for community energy, the impact could be substantial.

The benefits of 3,000 MW of installed capacity have been estimated at saving 1 million tonnes of CO_2e per annum and creating approximately 6,000 jobs. They also keep value within the local area, delivering income to local communities that can be used for other social projects. Finally, community energy can enhance engagement within local communities, with customers expressing a preference for locally generated supply.[43]

However, as we discuss in the previous section, there is limited evidence to suggest that meter splitting would materially increase the uptake of community energy without other, more substantive changes to the electricity system. The stakeholders we spoke to noted that P379 does not change the value stack within energy and so, the benefits from community energy projects were unlikely to increase as a result of the code modification.

5.5.3. Timescale for delivery benefits

Given that there are many community energy organisations that are active in developing generation assets and finding ways of directly supplying local consumers, we consider it is possible that any benefits that did materialise for community energy could start to do so in the short-term.

5.5.4. Uncertainty

Table 5.5 sets out the key sources of uncertainty in relation to this use case and what this means for the range of potential benefit.

[42] WPI Economics (2020) The future of community energy. Available at http://wpieconomics.com/site/wp-content/uploads/2020/01/Future-of-Community-Energy-20200129-Web-Spreads.pdf

[43] Regen (2015) Local supply: Options for selling your energy locally, 3rd Edition. Available at https://www.stephens-scown.co.uk/app/uploads/2015/07/LocalEnergySupply.pdf

Table 5.5: Assessment of uncertainty around benefits from community energy uptake

Source of uncertainty	Assessment of magnitude and potential impact on benefit
Value of social benefits of community energy	Studies of community energy have often identified the social value of community energy schemes as an evidence gap. Although there is recognition that such schemes have social value, the scale of benefits and their value in monetary terms is uncertain. We do not consider this uncertainty to materially affect our conclusions around the magnitude of benefit that will likely materialise through the implementation of P379.
Financial benefits from community energy schemes	Many proponents of community energy schemes and other forms of distributed electricity highlight the potential of such schemes to locate generation close to demand, mitigating the need for costly transmission (and to a lesser extent distribution) network reinforcement. The scale of the cost savings of community generation will depend substantially on their location, and whether they are located in areas where there is network congestion. Similarly, trials of community energy have found that they can lead to a behavioural response on the part of customers, encouraging them to switch demand to times when community-owned assets are generating. It is still uncertain however, whether this behavioural response is sustained.
Uptake of licence lite and wider reform of supplier licencing obligations	We have based our conclusions on the assumption that the current model of supply stays relatively similar to today, with the exception of meter splitting being implemented. However, if wider reform of supplier licencing obligations were to take place, or if licence lite was to become more widely adopted by community organisations, it is possible that meter splitting opportunities could complement wider reform such that it may have more of an impact on uptake. It is still unclear what such reforms could look like, and how they may interact with meter splitting.

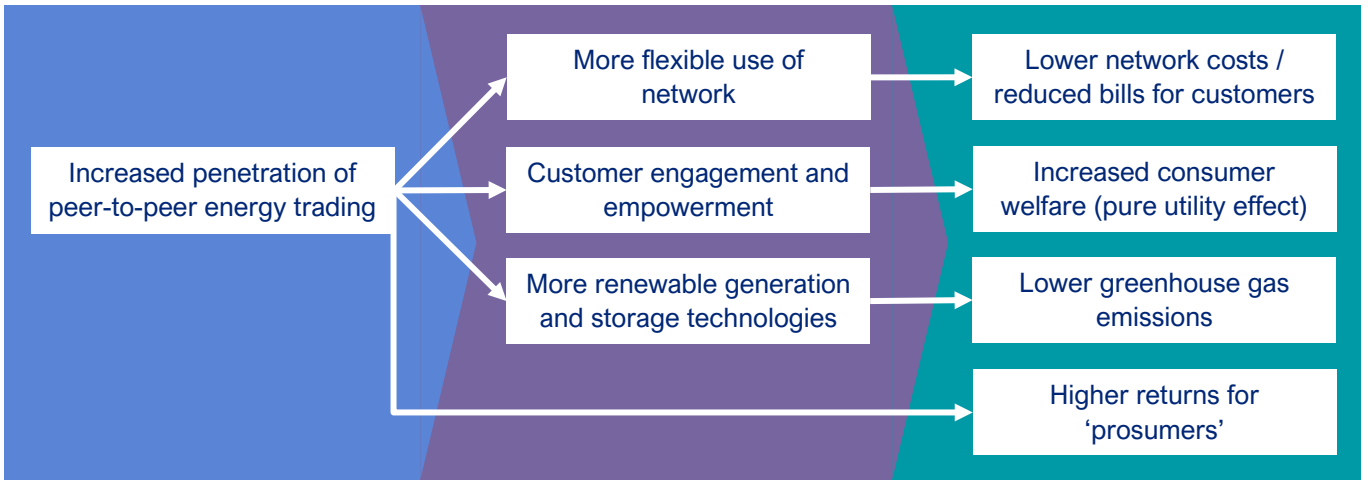
5.6. Additional uptake of Peer-to-Peer trading

Peer-to-peer trading, the buying and selling of energy between consumers, has been identified as another use case for P379. Under a peer-to-peer trading model, any electricity consumer with a generation asset like solar PV, or a storage asset, would be able to sell electricity directly to other consumers, whether households or non-domestic consumers. However, under current regulatory arrangements in the UK, direct peer-to-peer trading is not possible due to the requirement for consumers to purchase all of their electricity from a supplier intermediary. This means that peer-to-peer trading must be facilitated by suppliers.

The impact of this requirement is that peer-to-peer trading can only operate in a similar manner to a community energy scheme directly supplying local consumers. All participants in a peer-to-peer trading operation, would be required to switch to a single shared supplier who would then actively facilitate such trading. And any firms wishing to provide a trading platform, would be required to become licensed suppliers themselves, with all the associated obligations, or would need to partner up with an existing supplier.

We are testing the hypothesis that P379 could enhance the uptake of peer-to-peer trading by reducing the barriers for participants and platform providers. The benefits we expect to see from peer-to-peer trading are summarised in Figure 5.5.

Figure 5.5: Map of benefits from increased penetration of peer-to-peer services



The main benefit that is commonly associated with peer-to-peer trading, is access to better prices for both sellers and buyers. This would lead to lower bills for consumers and higher returns for prosumers – customers who both buy and sell electricity. This in turn could increase investment in small-scale renewable generation and storage technologies, which in turn could lead to lower greenhouse gas emissions. Greater localised generation may lead to lower usage of the transmission and distribution network, reducing network reinforcement costs and lowering customer bills if system efficiency benefits are realised. Further, some consumers may value purchasing electricity from neighbours or other local generators, instead of large-scale centralised generators.

5.6.1. Barriers alleviated by P379

As with community energy, P379 has been identified within the literature as playing a key role in the development of peer-to-peer trading.[44] The key barrier we have identified is the requirement for peer-to-peer trading to be actively facilitated by suppliers, either by suppliers hosting a trading platform, or by hosting platforms partnering up with existing suppliers. On the participant side, any consumer wishing to buy or sell electricity through peer-to-peer trading would need to switch to one of these suppliers for the entirety of their load.

We consider this presents a material barrier to the development of peer-to-peer trading under the current market and regulatory structure. The requirement for all consumers in a local area wishing to trade with peers, to switch to a single shared supplier, will likely limit the scale of any peer-to-peer market. There is also a risk of creating local monopolies where suppliers are able to extract rents from consumers participating in a peer-to-peer market, by offering unattractive tariffs for the consumption that is not locally traded.

However, we also note that the implementation of P379 is not a sufficient condition for the development of peer-to-peer trading. At a minimum, market-wide half hourly settlement and greater penetration of smart meters is required. Many stakeholders we spoke to also considered that, without reform of the supplier hub model, the transaction costs associated with having a supplier intermediary would make peer-to-peer trading unviable regardless of the implementation of P379. A secondary supplier would still need to have an electricity supply licence and so direct peer-to-peer trading would continue to face similar barriers. This view has been supported by some stakeholders, including some who have been actively involved in trials of peer-to-peer trading.

[44] See for example:

- EnergyREV (2020) Working Paper 2: Digital energy platforms. Available at https://www.energyrev.org.uk/media/1439/energyrev_digital-platforms_202007final.pdf
- Verv (2020) Case study: Peer-to-Peer Energy Trading. Available at https://verv.energy/research

Although it is possible that P379 alleviates certain barriers to peer-to-peer trading, experience of peer-to-peer trading thus far suggests that more fundamental regulatory barriers exist. The removal of these wider regulatory barriers would almost certainly have a more fundamental impact on P2P trading than would P379, whether or not it is implemented. In the absence of these wider changes, the benefits of P379 for P2P trading are likely to be negligible.

5.6.2. Magnitude and likelihood of potential benefit

The main potential benefit from peer-to-peer trading is allowing both buyers and sellers to arbitrage the difference between export tariffs and import tariffs. For a typical household in GB with solar panels, the difference between the two tariffs equates to approximately £79 per year, to be shared between buyer and seller. There are reasons to believe the return could be higher if consumers adopted dynamic time of use tariffs, allowing for more opportunities for peak shifting and price arbitrage. Studies looking at peer-to-peer trading in a European context have suggested that the savings to consumers could be 28%, while the returns to prosumers could increase by up to 55%.[45]

The second order effects of peer-to-peer trading may also be material, incentivising local renewable microgeneration, reducing emissions and reducing network reinforcement costs by locating generation closer to demand. Finally, there are the consumer well-being benefits from purchasing renewable energy and from purchasing from neighbours.[46]

Overall, however, we consider the potential magnitude of benefit to be almost negligible in the near to medium term as peer-to-peer trading faces wider, more material barriers. If peer-to-peer trading does emerge in the longer term, meter splitting may support growth, but it is unlikely to be a fundamental driver of success.

5.6.3. Timescale for delivering benefits

Of the use cases we have considered in this report, peer-to-peer trading is widely considered in both the literature and in stakeholder engagement, to be the one focused furthest into the future. Given widespread participation in peer-to-peer trading will require other market and regulatory developments, we do not consider it likely that the benefits from peer-to-peer trading will materialise at scale during the appraisal period.

5.6.4. Uncertainty

Table 5.6 sets out the key sources of uncertainty in relation to this use case and what this means for the range of potential benefit.

[45] Neves et al (2020) Peer-to-peer energy trading potential: An assessment for the residential sector under different technology and tariff availabilities. Available at https://www.sciencedirect.com/science/article/abs/pii/S0360544220311300

[46] Impact (2019) Future Energy Models: Research findings report. Prepared for Citizens Advice. Available at https://www.citizensadvice.org.uk/Global/CitizensAdvice/Energy/915%20Citizens%20Advice%20Future%20Energy%20Models%20Report%20Final%20v2.pdf

Table 5.6: Assessment of uncertainty around benefits from peer-to-peer trading

Source of uncertainty	Assessment of magnitude and potential impact on benefit
Financial benefits from peer-to-peer trading	We have cited some studies considering the potential benefit to consumers and prosumers from peer-to-peer trading, but many of these are theoretical calculations. Importantly, they do not capture the potential transaction costs associated with such trading. It is possible that these transaction costs are large enough to make peer-to-peer trading unviable, regardless of whether meter splitting exists.
Interaction of other market and regulatory reforms with P379	Another related issue is how P379 will interact with other market and regulatory reforms. It is unclear whether P379 will be sufficient to enable peer-to-peer trading in the absence of these other reforms, with the transaction costs and overhead from the secondary suppliers potentially making the model unviable. On the other hand, should these other reforms be implemented to allow consumers and prosumers to trade directly with one another, it may be that P379 is no longer necessary or only provides marginal benefit.

6. DISTRIBUTIONAL EFFECTS

In this section we consider the potential for distributional impacts. We firstly consider the potential for distributional effects across different types of suppliers. In terms of developing an assessment of social, and in particular, consumer welfare, our CBA is indifferent to distributional impacts on suppliers to the extent that this does not in turn impact on consumers or society more generally. However, in many cases, distributional impacts on suppliers could in turn lead to impacts on consumers.

In Section 6.2, we summarise the potential for distributional effects on different types of consumers, either as a consequence of impacts on suppliers or more directly.

6.1. SUPPLIER ARCHETYPES

We consider the potential for P379 to have distributional impacts on suppliers in two ways:

1. Distributional impacts between primary and the secondary suppliers.
2. Distributional impacts between different primary supplier types.

We discuss both cases below.

6.1.1. Distributional impacts between primary and secondary suppliers

Under P379, primary and secondary suppliers would take on different obligations and responsibilities in some areas, the exact details of which may depend on finalisation of the solution and wider consequential change, e.g., in relation to supplier licences.

Several stakeholders indicated concerns that P379 could lead to a 'two tier' supply market in which secondary suppliers are able to offer cheaper rates for supply of electricity because they avoid certain costs. In particular, stakeholders noted that primary suppliers would be responsible for the fixed charge element of network charges. We have previously discussed the potential for primary suppliers to take on additional volume risk given the ability of secondary suppliers to finalise Customer Volume Notifications one hour prior to delivery. Where this does allow secondary suppliers to provide cheaper rates, this would not reflect actual efficiencies but would transfer 'per unit' costs from the secondary to the primary supplier.

At least in theory, the market would find a new equilibrium. All customers of a secondary supplier require a primary supplier and the costs of delivering electricity for the primary and secondary supplier should reflect the associated cost base. Primary suppliers would therefore continue to compete with primary suppliers for delivery of primary supply while also providing a service that the secondary supplier does not – i.e., the ability of a consumer to have electricity delivered and the option value of secondary supply. As lower unit rates from the secondary supplier would be reflected in an increase in rates for the primary supplier, a rational consumer would only choose to take on secondary supply for the proportion of electricity volumes for which it identifies some additional value from doing so. So long as the depth of both the primary and secondary markets are sufficient to ensure effective and efficient competition this may not be a problem in of itself.

However, this equilibrium depends on two assumptions:

1. That lower unit rates of secondary supply result in a direct transfer of cost, resulting in increased rates of primary supply ***for the same consumer.***
2. That consumers have the information and understanding to identify this transfer such that they do not consider secondary supply to be cheaper once the full costs of supply are accounted for.

The first assumption depends on the final details of the P379 solution and on the approach of primary suppliers in recovering additional costs where consumers choose to take up secondary supply. If primary suppliers can, and choose to, increase the rates for an individual consumer to reflect the transfer of cost from secondary to primary

supply volumes then the assumption holds. However, primary suppliers may instead spread additional costs across their full consumer base, increasing unit rates for all of their consumers.

The second assumption effectively requires consumers to act rationally in response to differences in the unit rates of primary and secondary supply. This is dependent on the first assumption holding and on consumers having a clear understanding of the price differentials between primary and secondary supply. Informational and engagement challenges may limit the extent to which this is the case, particularly if take-up of meter splitting opportunities moves beyond more engaged sectors of the market.

This introduces the potential for an alternative outcome to the new equilibrium set out above. Under this scenario, unfair competition develops between primary and secondary suppliers. Consumers identify both to be operating within the same market but favour secondary suppliers due to hidden cost advantages or given the socialisation of secondary supplier costs. Under this scenario, there is greater scope for unintended consequences to materialise, including distributional transfers from customers of primary suppliers to customers of secondary suppliers. This may also generate a feedback loop as greater take-up of secondary supply exacerbates the cost differential between primary and secondary suppliers.

6.1.2. Distributional impacts between primary supplier types

In addition to distributional impacts between primary and secondary suppliers, we also note the potential for primary suppliers to be affected to differing extents. Take up of secondary supply is more likely to be undertaken by more engaged consumers. Particularly in the early years following implementation, our assessment of use cases suggests that take-up would be primarily driven by those with EVs, heat pumps or batteries who are also likely to be the more engaged and informed consumers in the market.

EV use is projected to rise significantly over the course of our analytical time horizon, particularly under the CT scenario in which we frame our analysis. However, even under optimistic projections of take-up of meter splitting, we would anticipate take-up being more likely for engaged consumers who are more open to new and innovative tariffs.

We have noted some of the challenges that may sit with primary suppliers who are responsible for the load of customers who choose to adopt secondary supply. Respondents indicated that several cost areas including costs to serve, and volume risk would increase with higher take-up levels. They also noted that additional risks may sit with suppliers of customers with secondary supply such as the volume risk associated with failure of the secondary supplier.

Some of the respondents to our consultation suggested that the combination of higher take up rates for engaged, early technology adopters and increased supplier costs with take-up could lead to a perverse outcome. They argued that P379 could disproportionately impact innovative primary suppliers who are leading the way in areas such as time-of-use tariffs and elective half-hourly settlement. By disproportionately increasing cost and risk for these primary suppliers, they felt that P379 could in fact discourage innovation by introducing a ‘penalty’ or risk associated with supplying such customers.

6.2. Consumer archetypes

The most direct way in which P379 is likely to have distributional impacts on consumers is as a result of engagement in the sector. All of the use cases that we considered for meter splitting are more likely to be adopted by consumers who are already engaged in the market. The use case that we consider to be the most likely driver of take-up is in relation to separation of supply for EVs, heat pumps and/or batteries.

While engagement[47] has been increasing in recent years[48], slightly more than half of energy consumers continue to be fully disengaged. Under the CT scenario, there are estimated to be close to 19 million residential EVs on the road by 2033 (the end of our assessment period). However, growth is faster in the second half of the period with just over 5 million residential EVs in 2027. Take up of heat pumps is steadier with just over 3 million by 2027 and close to 8 million by 2033. Domestic battery take-up remains relatively low over the period.

In combination, we would expect take-up of meter splitting to be primarily targeted within a relatively small consumer sub-set who adopt these technologies and derive benefit from one of the specialised use cases we have discussed previously. EV ownership is disproportionately focused within higher income socio-economic groups[49]. While there are policy support options available for installation of heat pumps, the up-front costs of both heat pumps and batteries are likely to discourage take up amongst the lower income classes. The direct beneficiaries of meter splitting are therefore likely to be relatively higher income consumers, particularly in the short term before EV and heat pump penetration increases amongst lower income groups.

Detailed design questions remain regarding how additional costs of P379 for primary suppliers would be recovered from consumers. We set out two conditions that would need to hold for primary suppliers to be able to target costs onto secondary supply customers in Section 6.1.1. In the case that additional costs and risk to primary suppliers can be targeted on those customers who choose to adopt secondary supply, distributional impacts on consumers may be more limited. Nevertheless, we identify certain use cases, such as the 'cherry picking' benefit of arbitrage between suppliers, that may result in distributional rather than absolute effects. We also consider it unlikely that suppliers would have the means to observe and target the increased costs of secondary supply in full.

Given this, there is a risk of lower income groups, and more generally, those who are less engaged in the market, absorbing additional costs.

[47] Defined as those who have switched supplier or tariff, and/or have compared supplier or tariff in the previous 12 months.

[48] See Ofgem's Consumer Engagement Survey (2019): https://www.ofgem.gov.uk/system/files/docs/2020/02/2019_consumer_survey_report_0.pdf

[49] https://www.green-alliance.org.uk/resources/going_electric_how_everyone_can_benefit_sooner.pdf

7. RISKS AND UNINTENDED CONSEQUENCES

7.1. SUMMARY OF RISKS AND UNINTENDED CONSEQUENCES

Through the stakeholder engagement process, we identified several potential risks and unintended consequences from P379. Below, we describe the risks and unintended consequences most frequently raised by stakeholders. Whether these risks materialise will depend significantly on how P379 is implemented alongside wider regulatory and code reform, particularly around supplier requirements when there are multiple suppliers per customer.

This is not necessarily a comprehensive list, but it does capture what we consider to be the most material risks.

7.1.1. Risks to consumers

There are some potential risks to consumers and unintended consequences for the consumer experience related to meter splitting. It is worth noting that most of the following are risks to consumers who voluntarily opt for a second supplier through meter splitting, rather than introducing market-wide effects. It is therefore reasonable to assume that the scope for actual consumer harm would be limited to some extent by the need for consumers to voluntarily enter into such arrangements. We would also expect there to be an incentive on secondary suppliers to develop arrangements to resolve/minimise issues where possible. Nevertheless, these issues, if material, could introduce 'frictions' into secondary supply, potentially limiting appetite for take-up,

Misleading price comparisons and quotations – One of the unintended consequences identified by stakeholders was the difficulty in making price comparisons in a scenario where there are multiple suppliers behind the meter. It is quite likely that the tariff on offer by a primary supplier will need to change if secondary supply is introduced. As such, a price comparison may potentially be misleading if it does not reflect this tariff adjustment when considering options for secondary supply. Similarly, quotations by prospective secondary suppliers may also be misleading if they do not account for any potential tariff changes by the primary supplier. This would make it difficult for customers to determine whether contracting with a secondary supplier will provide a financial return.

Another related issue is the challenge in making appropriate price comparisons in a context where it is unclear exactly what proportion of a customer's load will be served by a secondary supplier versus a primary supplier. Such issues are not necessarily unique to P379, however, with the introduction of time of use tariffs and specialist tariffs for EV charging etc. all making price comparisons more challenging.

Poor experiences during home moves / switching / disconnections –The process for home moves, switching and disconnections are all yet to be determined in the P379 solution, as these issues need to be considered more broadly, including by Ofgem[50]. Nevertheless, many suppliers have argued that there are material risks to the customer experience during these processes, given the added complexity from the involvement of multiple parties. Suppliers noted that poor customer experiences can be exacerbated where it is unclear who is responsible for resolving an issue, and customers are passed from one party to another.

Smart meters becoming less useful – One of the primary motivations for the introduction of smart meters was to allow customers to track their usage and expenditure on a close to real time basis. However, under many of the split-meter secondary supply models we have considered, the usefulness of smart meters in providing this function is at risk of being undermined. Based on existing smart metering arrangement, the volumes presented on the smart meter will only show aggregate volume, and costs will be estimated based on the tariff set by the primary supplier. As a result, the cost estimates would become inaccurate. In turn, this may undermine the use of smart meters, including in relation to innovative supplier tariffs and services.

[50] While the solution does include a process for change of customer, the BSC solution is limited to the existing process which places the burden on the customer to notify of the change.

There will need to be an evolution in the smart metering arrangements for customers, including integration of sub-meters with the main meter, to allow for information to be presented to customers accurately. For example, where secondary suppliers offer a bundled service, the volumes involved would need to be tracked and communicated to the main smart meter. This can then be deducted from total volumes on a close to real time basis, to allow customers to track their expenditure for the remaining load.

Poor experience from supplier disputes – Finally, there is a risk that customers are caught in the middle of supplier disputes, leading to a bad customer experience. As an illustrative example, work undertaken by a primary supplier may inadvertently cause equipment owned by the secondary supplier to stop working (e.g., an EV charge or some smart flexibility technology). The customer would then be caught in any dispute between the two suppliers as to the responsibility for resolving the issue.

7.1.2. Risks to market

In addition to effects on consumers, there are some potential risks and unintended consequences on the supplier side of the market.

Allocation of network and policy costs – The exact method for allocating network and policy costs between primary and secondary suppliers is yet to be determined, though it is expected that fixed costs would rest with the primary supplier and variable costs would be shared between suppliers depending on respective volumes. If there is a high take up of secondary supply, there is a risk that this leads to a more fundamental change in market structure, creating a two-tier system. Primary suppliers and secondary suppliers would not be competing on the same basis as they would have different tariff structures to reflect their different cost bases. For example, we would expect primary suppliers to have much higher standing charges to reflect their higher fixed costs.

We explore what the impact of this might be on primary and secondary suppliers in Section 6.

Higher costs and barriers to entry for suppliers – There is a risk that secondary supply duplicates many of the fixed costs involved with supply for a single customer, such as billing, credit management, customer service, etc. Many stakeholders we spoke to noted that suppliers often aim for scale to allow recovery of these substantial fixed costs over a large customer base. Secondary supply risks making this more challenging by increasing fixed costs. This could, perversely, introduce additional barriers to entry for new entrant primary or secondary suppliers.

7.1.3. Other risks

Opportunity costs of pursuing P379 – We received feedback from multiple stakeholders that P379 would be a substantial change in how the market is structured and regulated. As a result, it would require substantial resource to design the detail around the solution and then implement it. Further work is required around how exactly network and policy costs are allocated between multiple suppliers, and consequential changes are likely to be needed around supplier licensing obligations, DCUSA code changes and the smart meter rollout, among others. It is possible that the time and resource costs associated with designing and implementing P379 lead to other, more valuable reforms being deprioritised or limited in scope.

8. COMPARING COSTS AND BENEFITS

In this section, we bring together our analysis of costs, risks and unintended consequences, and benefits to consider whether P379 may demonstrate a positive benefits case under our break-even analysis framework (Section 3).

8.1. RANGE OF DIRECT COSTS, RISK AND UNINTENDED CONSEQUENCES

While the extent of direct financial costs (Section 4) remains subject to a broad degree of uncertainty, we agree with respondents that the finalisation of design and implementation of P379 would constitute large, complex change. Given the inter-dependencies between potential costs and benefits with broader codes and regulations and wider ongoing reform, we can see merit in the suggestion from several stakeholders that P379 would need to be finalised through an Ofgem SCR[51].

Our analysis of the evidence base submitted by stakeholders suggests that it is primarily changes to electricity supplier systems and processes that would drive most of the direct financial cost and that these costs could be significant. The few numerical cost estimates that we did receive indicate discounted costs for implementation within the domestic consumer base of between £84 million and £526 million over the 10-year period at low take up levels of approximately 0.1%. At more optimistic take-up levels of 10% of domestic consumers, these cost estimates rise to between £2.3 billion and £2.6 billion (NPV, £2021). Implementation across non-domestic consumers would increase costs significantly.

Implementation requirements on industry participants other than suppliers would be less significant but would introduce non-negligible additional financial costs, nonetheless. In addition to direct financial costs, we have set out several risks and unintended consequences of P379 in Section 7.

In combination, these direct financial costs, risks and unintended consequences indicate that the likelihood and scale of benefit must be considered separately when assessing whether the benefits case of P379 is likely to be sufficient to outweigh costs.

Implications of cost estimates for required benefits

While many of the cost components identified by suppliers scale with take-up of secondary supply, a sizeable proportion of cost would be incurred regardless of take-up levels. Up front systems and process changes would be needed to enable meter splitting. One of the suppliers who provided numerical estimates indicated that more than 20% of the costs of implementing P379 at 10% take-up levels would still be needed, even with very low take-up of 0.1%. Many of the wider costs falling on industry participants other than suppliers would be fixed, up-front costs that would be incurred regardless of take-up levels. In addition to direct financial costs, substantial industry time and resources would be needed to develop and implement the solution regardless of take-up.

This emphasises the importance of having a good degree of certainty in the likelihood of benefits of meter splitting. A positive benefits case is likely to depend on achieving relatively high levels of take-up. This would allow for economies of scale to be achieved and for the additional benefit to overcome up front fixed cost requirements.

Given the level of complexity that remains in developing and implementing the P379 solution, and the costs involved in doing so, even if reasonably high levels of take-up are achieved, the magnitude of benefit per customer needs to also be high to overcome variable cost items that increase with take-up.

[51] Ofgem has the option to bring complex code decisions in house and develop them through a SCR. SCRs are multi-year reviews of strategically important areas of the energy industry in which Ofgem leads the development of change through close engagement with the industry.

The majority of benefit needs to be absolute rather than distributional. Our analysis (Section 6) suggests that it is higher-income customers who are disproportionately likely to benefit, particularly in the early part of the period. Where benefit is achieved through socialising additional cost and risk onto others, this may result in a transfer from lower to higher-income households.

Finally, implementation of the solution needs to navigate the potential for risks and unintended consequences so as to minimise the extent to which some of this benefit is eroded by disbenefit in other areas.

8.2. Consideration of benefits

We have considered the likelihood and magnitude of benefit in relation to the four use cases that we have tested with stakeholders (Section 5).

Likelihood of benefit

Advocates of P379 highlight the emergence of EVs and heat pumps as drivers of benefit from multiple supply options. They set out the case for meter splitting based on a belief that innovation and specialised services for EV and heat pump users in particular, would emerge both from within the energy market and from tangential markets. This is in the context of consensus from market commentators (including in the FES) who forecast exponential growth of EVs and steady growth of heat pump use over the next ten years.

Our engagement suggests that bundling and specialised services in the EV and heat pump markets represent the most promising use cases for meter splitting. We consider it highly likely that at least *some* benefit would be generated through this use case. And we note that it is difficult to foresee the extent to which unknown innovation may emerge in the presence of meter splitting opportunities.

However, we question the certainty with which we might expect these use cases to drive the take-up levels needed to reflect the up-front implementation costs of P379. Many of the specific approaches that have been proposed could already be delivered in similar ways through existing or emerging routes to market. Once we take these alternatives into account, the set of non-substitutable use cases that meter splitting could deliver becomes increasingly small. Engagement with potential entrants from the EV and HaaS markets suggests that their leading option for entry into the market, at least in the short-medium term, is through partnering with existing primary suppliers. We are already observing innovative new services and products enter into the market through this approach.

Magnitude of benefit

Our analysis also suggests that it is in relation to products and services in the EV and heat pump market that we might expect the greatest materiality of benefit. But again, this is limited by the size of the set of use cases that could not be achieved through other means. We expect that certain types of innovation might materialise that cannot currently be identified. However, there is very little certainty that this innovation may provide real benefit to more than a relatively small sub-set of consumers.

It is also difficult to say at the current time whether the scope for potential risks, unintended consequences and distributional impacts could be alleviated. Many of these are dependent on wider developments and design decisions outside of the BSC.

8.3. Conclusions

We conclude that a strong case cannot be made to suggest that the benefits of meter splitting are likely to outweigh the costs at this time. While some uncertainty exists regarding both costs and benefits, based on our engagement with stakeholders and review of the evidence, we ascribe a relatively high level of certainty to this assessment.

The only additional evidence that could lead to an alternative conclusion would be a demonstration that there are significant levels of innovation that would emerge that cannot currently enter into the market through other means

and that would be adopted by a substantial volume of customers. While predicting the emergence of unknown innovation is one of the most challenging areas in which to gather evidence, we have sought to engage with a relatively broad range of stakeholders to inform our view, commensurate with the scope, timing and scale of the project. Our assessment suggests that forming a positive benefits case based on this mechanism would be too reliant on the benefits from these unknown innovations.

Developments which could affect a CBA of meter splitting

There is significant potential for both costs and benefits to change over time due to:

- ongoing industry change in other areas of the market;
- changes to consumer trends and behaviours; and
- emerging business models in the electricity sector.

Ongoing changes in the sector may affect both costs and benefits of P379. Several respondents to our consultation identified the potential for significant efficiencies in implementing MHHS before P379. To the extent that use cases and benefits of P379 do materialise, wider developments are also likely to act as enablers, increasing likely levels of take-up and the size of the market for innovation.

At the same time, as consumers increasingly adopt EVs and heat pumps and as companies in tangential sectors consider their entry strategies more fully, ‘innovation gaps’ and consumer appetite for these forms of innovation may become clearer.

For this reason, it may be necessary to re-consider the merits of meter splitting at some stage in the future. The EV and HaaS stakeholders that we spoke to both mentioned a five-year time horizon in relation to thinking about the development of alternative business models for their offerings into the electricity sector. A five-year checkpoint would also allow time for MHHS and use of smart meters to bed in and for EV and heat-pump use to become more prevalent. If meter splitting is re-considered, there may be merit in ‘trialling’ to develop more certainty of potential benefits, costs and implementation challenges before developing the solution in full.

Appendix A SUMMARY OF STAKEHOLDER ENGAGEMENT

A.1. Workshop with BSC Panel

In December 2020, we facilitated a workshop with the BSC Panel[52] to discuss the analytical framework that we proposed to use and our approach for assessing the individual costs and benefits. We followed this up with an optional smaller, dedicated session with some Panel members.

Broadly, Panel members supported our high-level approach to the analysis and use of quantitative and qualitative assessment techniques. One member warned that it may be more difficult than we expected to get a clear view of costs from businesses.

A portion of the discussion covered potential risks and unintended consequences from the proposed modification, some of which fell outside the cost and benefit categories that we had identified. It was thought that our approach might not capture the full range of implementation issues that would need to be overcome. In response we committed to undertake more analysis on potential risks, unintended consequences and distributional impacts to ensure that these would be adequately captured in our reporting.

One Panel member questioned the lack of primary analysis in our proposed approach to assessing benefits. They thought that the formal stakeholder consultation may not capture new innovators who could benefit from P379. In response, we sought to diversify our stakeholder engagement through a series of semi-structured interviews with stakeholders. The summary of these is provided in A.4.

A.2. Open workshop with industry stakeholders

In December 2020, Elexon and CEPA hosted a public workshop for industry stakeholders. A total of 54 attendees attended the five-hour workshop, including individuals representing suppliers, Ofgem, code administrators, software providers, academics, community groups and not-for-profit organisations.

The workshop material can be found on Elexon's website.[53] CEPA's contribution followed a similar structure to the workshop with the BSC Panel; we presented and discussed our high-level approach and the potential benefits and financial costs of P379.

There was limited feedback from stakeholders for our proposed analytical approach but those who did respond generally provided tentative support, while noting challenges with the CBA. Some stakeholders sought clarifications about our methodology and assumptions, such as asking whether we would include impacts on CO2-e emissions, consumer satisfaction, job creation or the potential for future market design changes. Several stakeholders requested that the impact assessment consider the distributional impacts across different consumer groups and types of suppliers. Where possible and material, we have taken on these comments to develop our final approach.

Some stakeholders questioned the value of undertaking an impact assessment when they perceived that the design for P379 was at an early stage and the benefits are uncertain and difficult to quantify.

Stakeholders were invited to vote on the likely take-up and benefit associated with the P379 use cases explored in this report. A majority thought that, by 2030, between 100,000 and 1,000,000 customers might choose specialist suppliers or bundled products using secondary suppliers if P379 was to be implemented. A further 25 per cent of respondents thought that uptake would be negligible (<10,000).

[52] https://www.elexon.co.uk/group/the-panel/

[53] See: https://www.elexon.co.uk/meeting/p379-cost-benefit-analysis-stakeholder-workshop/

There were mixed views on the likely increase in the number of customers taking up community energy due to P379 – 26 per cent predicted a negligible increase (+0-10%), 35 per cent a small increase (+10-25%) and 22 per cent a medium increase (+25-50%).

Stakeholders were sceptical about the likelihood of P379 leading to an increase in peer-to-peer trading – 56 per cent of respondents thought that the increase would be negligible (<10,000 additional customers). A few stakeholders thought that there was a risk of missing out on innovation if P379 is not progressed.

Some stakeholders suggested further use-cases and benefits of P379 which we have reflected on and attempted to capture in this impact assessment where relevant and material.

We set out our proposed approach to the assessment of costs and a hypothesis for each cost category already identified. Stakeholders commented on the likely magnitude of each cost item. Stakeholders generally identified a high level of uncertainty but also a high materiality of several cost items. The costs associated with changes to billing and settlement systems were expected to be the most material.

We asked stakeholders about the possible risks or unintended consequences that could result from P379. In addition to the issues around free-riding, complexity, supplier disputes and bundling that we had already identified, stakeholders noted further issues relating to mis-selling, balancing mechanism impacts from higher forecasting errors, interactions with the faster switching reforms, data ownership/access and industry resourcing for large reforms. Several stakeholders noted that P379 should be dealt with by Ofgem through a SCR as the issues stretch beyond the BSC.

A.3. Consultation responses

On 24 November 2020, Elexon issued a consultation which we helped to develop, with responses invited by 22 January 2021. Elexon received 14 responses from stakeholders who had completed the response form as well as four letters from other stakeholders. The non-confidential responses can be viewed on Elexon's website.[54]

A summary of these responses is provided below.

Suppliers

Seven suppliers responded to the consultation, representing a range of different business types and market segments.

Three substantively completed the cost template with corresponding justification provided. To enable comparison, we have converted these costs into a £ per customer/meter point metric by dividing each cost item by the number of customers served by the respective supplier. We assume that annual cost estimates apply over the full 10-year appraisal period. These normalised costs for the low (0.1% of customers), medium (1%) and high (10%) uptake scenarios are set out in the following figures. ✂ [redacted]

[54] See: https://www.elexon.co.uk/documents/change/modifications/p351-p400/p379-cost-benefit-analysis-consultation-collated-responses/

[55] ✂ [redacted]

Figure 8.1: Disaggregated costs for Supplier A (Domestic)

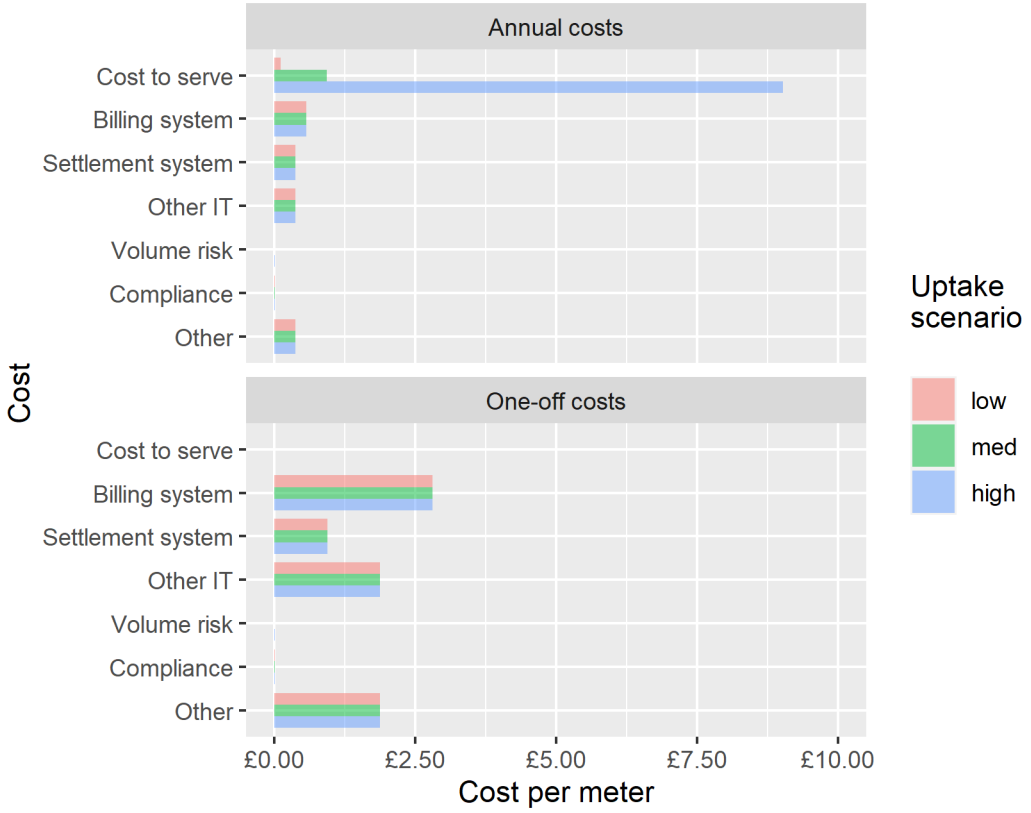
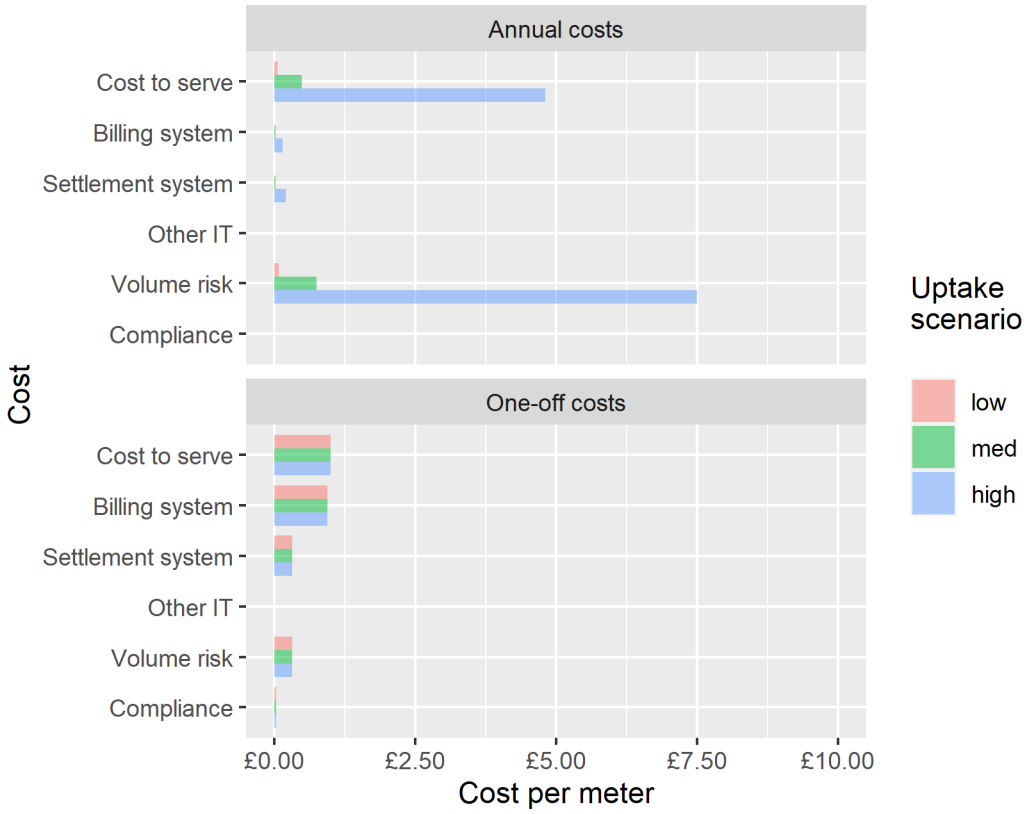


Figure 8.2: Disaggregated costs for Supplier B (Domestic)



[redacted]

[redacted]

Suppliers were generally sceptical about the potential benefits and use-cases of P379. Some provided examples where similar services are already being investigated or provided by suppliers. Most thought that the current absence of meter splitting was not the main reason for the use-cases associated with P379 being underrepresented. They cited other barriers which they thought provided a better explanation for current uptake levels.

All suppliers identified perceived risks and the potential for unintended consequences. They saw the potential for significant new complexity which would increase supplier costs and impact negatively on the consumer experience. They noted a range of situations in which the addition of secondary suppliers would heighten the potential for disputes between suppliers, which could also negatively impact on consumers.

One supplier thought that the costs associated with managing volume risk could be negligible if secondary supply uptake is gradual, whereas other suppliers thought that this cost could be more significant. Another disagreed and noted that the mitigating actions could be detrimental to consumers, such as increased risk premiums and removing customers that have engaged secondary suppliers from the standard pricing structure.

Most suppliers were concerned about how the Supplier of Last Resort (SoLR) process would operate in the presence of secondary suppliers. Several noted that there would be a concentrated risk for primary suppliers if consumption was to default back to the primary supplier if a secondary supplier fails.

Several respondents noted that P379 could perversely act as a barrier to entry if it increases cost and risk of primary supply to the extent that it acts as a barrier to entry in that market.

Supplier agents

Three supplier agents provided cost estimates across the categories of HHOA, HHDC and HHDA and explained how they would implement the changes. One expected no costs relating to its HHOA operations whereas the other one expected some costs and said that they would be incremental to P375.

Licensed Distribution System Operators

Three LDSOs responded to the consultation. All noted that it was difficult to develop accurate cost forecasts due to uncertainty around the design and level of uptake. Despite this, two provided estimates of their likely costs to implement and provide P379 on an on-going basis. One said that it expected to have to create more MPANs and this would impact on server space. They considered that they would experience an on-going increase in database and resourcing costs. Another noted that they would need to make changes to support billing of both primary and secondary suppliers but didn't estimate its likely costs.

One thought that the potential benefits of P379 seemed reasonable in principle but questioned whether the market would evolve to need this solution and whether it would be of interest to consumers. It thought that the benefits of P379 are already being delivered by P375.

Two LDSOs noted potential issues relating to DUoS charges under P379. One advocated for all network charges to be billed to the primary supplier and split 'behind the scenes'. It thought that this would be simpler for suppliers and avoid complex, potentially unworkable, solutions in the case of supplier failure. Another LDSO also identified a range of issues concerning the management of DUoS charges in the case of supplier failures (primary or secondary).

Other stakeholders

One stakeholder set out several concerns that is has about the impact of P379 on the smart meter implementation programme. It noted the potential for quantity and cost information on in-home displays to be inaccurate. It also noted the likelihood of confusion around consumer billing data, the added complexity of disconnections if there are multiple suppliers and issues with using non-SMETS CoP11 meters. It considered that the impacts on the programme are more nuanced than set out in the CBA scoping document.

Two stakeholders indicated support in the belief that P379 would facilitate EV charging of home-parked fleet vehicles and that it would provide choice to tenants who might otherwise have a supplier imposed by a landlord. Both stakeholders noted the example of shared telecommunications infrastructure where one network provider hosts another network and charges them for electricity.

A.4. Semi-structured interviews

We held a series of semi-structured interviews with twelve stakeholders, covering a broad range of industry and non-industry participants. We used these interviews to explore use cases, risks and unintended consequences, and potential routes to market for the different innovative business models. We spoke with a range of suppliers, serving domestic and non-domestic customers, operating at different scales, and those that were actively involved in trailing new tariffs and new business and market models. We also spoke with community energy organisations, industry observers, Ofgem, an EV manufacturer and a supplier of heating and hot water solutions.

The consensus from industry participants was that the key opportunities from secondary supply centred around the provision of new services targeted at customer EV and heat pump usage. Stakeholders were more sceptical around the impact of P379 on the development of community energy and peer-to-peer trading, while many stakeholders struggled to see the efficiency benefits from arbitrage opportunities.

Stakeholders disagreed on two key issues:

- Whether existing suppliers and the existing market structure provided the environment for the development of new business models to exploit the potential for community energy, peer-to-peer trading, bundling and consumer-derived flexibility. While some stakeholders pointed to existing market developments as a positive sign, others argued that the market was insufficiently innovative and the regulatory environment insufficiently permissive to allow such innovations to become mainstream even in the presence of meter splitting.
- Whether P379 would act as an enabler for further innovation and regulatory change, or whether it would distract from other more beneficial market reforms. Stakeholder perceptions on this issue largely correlated

with stakeholder perceptions on the previous issue. Those who saw the existing market and regulatory structure as insufficiently permissive generally considered P379 as a positive move.

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