P415 – Cost Benefit Analysis, Methodology

Elexon

3 March 2022

WORKING NOTE

CEPA
economics matters

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This document is subject to contract. Should this proposal be acceptable, we would be pleased to agree the terms and conditions prior to our appointment.

Contents

1. SCOPE

1.1. Context for the CBA

Flexibility – including demand-side flexibility from consumers – can help lower the costs of decarbonisation. For example, a 2021 analysis by Carbon Trust and Imperial College estimated potential savings of £10-17 billion per annum across the GB economy from making effective use of flexible energy resources.

Sources of flexibility are expected to grow over time as digitalisation and energy technologies (e.g., energy storage, electric vehicles, heat pumps and distributed generation) become increasingly prevalent. Consumers and suppliers are seeking to exploit new opportunities through innovative offerings and novel modes of electricity generation, consumption, and transmission.

P415 was raised in late 2020 and proposes to allow flexible energy volumes to be sold by Virtual Lead Parties (VLPs) in the wholesale market with no involvement from suppliers. These upwards and downwards actions could represent an additional source of 'demand side response' (DSR). This would introduce benefits to consumers by enhancing flexibility of demand to meet periods of high-RES output, potentially reducing wholesale market prices, carbon emissions and the generation capacity needed to meet demand. It may also alleviate pressure on network capacity and introduce positive externalities as additional DSR volumes participate in other markets, in particular the balancing market

However, P415 would also introduce new costs. The solution will require new systems and processes to measure VLP flexibility volumes. The modification may also have a range of impacts on multiple market participants. In particular, downwards DSR actions by aggregators may cause suppliers to be 'out of pocket' for their costs of hedging the full level of consumption. The proposed solution involves the payment of compensation to affected suppliers. The P415 Workgroup has developed two alternative compensation mechanisms for consideration in the CBA.

1.2. Purpose of the CBA

The purpose of this CBA is to provide information to the BSC Panel, P415 Proposer and P415 Workgroup on the potential benefits, costs and other impacts of implementing P415. It is also intended to inform Ofgem's decision on whether to approve P415 for implementation. As well as considering the merits of P415 relative to the counterfactual in which P415 is not implemented, the CBA is intended to support comparison of the two compensation variants to evaluate how the costs and benefits are impacted by each design.

1.3. Structure of this Methodology Note

In this note we set out our intended methodology for the CBA of P415. We structure this note as follows:

- In Section 2, we outline our high-level approach and our methodology for evaluating the benefits and costs captured in our analysis.
- In Section 3, we provide further detail on the modelling framework used to analyse key benefits. We also describe several of the key assumptions for the analysis.

We will proceed with a period of testing and calibration of the models in March 2022. While this note sets out our intended methodology, we may adapt our approach to reflect results from testing and calibration if we determine that this will enable a more robust CBA. Any changes relative to the methodology set out in this note will be discussed and agreed with Elexon.

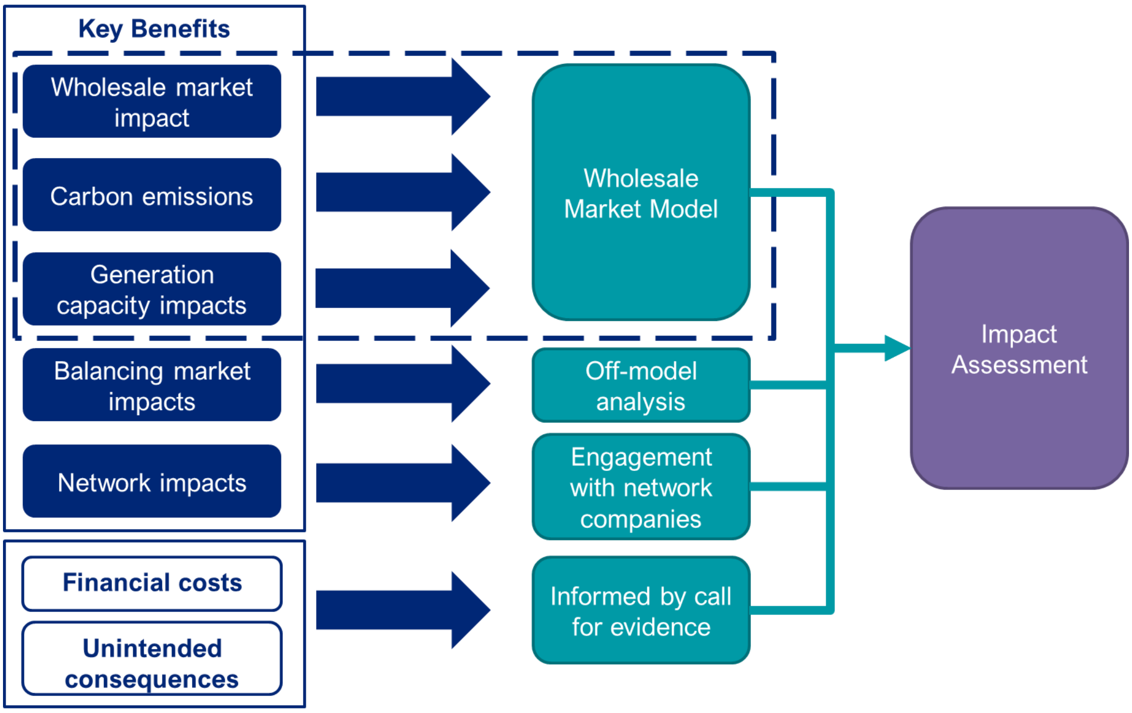
2. HIGH-LEVEL APPROACH

We will assess the key benefits and costs of two P415 variants against a counterfactual in which we assume that P415 is not implemented. Our approach is designed to assess the key expected benefits and costs of P415, using a range of analytical methods.

The assessment of benefits and costs will be brought together within an impact assessment model that will consider the overall net present value impact of P415 as well as the distribution of costs and benefits amongst market participants.

We summarise our high-level approach in Figure 2.1.

Figure 2.1: Summary of our high-level approach



Impact Assessment

The overall impact assessment will bring together the range of benefits and costs. Monetised costs and benefits will be combined to estimate a net present value of the proposed reform. The quantified analysis will be supplemented with a summary of qualitative costs and benefits where quantification is not possible. We will seek to provide an indication of the order of magnitude of these costs and benefits in comparison to the quantified assessment to the extent possible.

Our analysis will also allow for distributional effects of P415 to be considered. As well as an assessment of consumer welfare, our quantitative analysis will also allow for assessment of impacts on the producer surplus of:

- **VLPs**, who will benefit from a new revenue stream but face costs of doing so.
- **Generators**, who will be affected by the change in prices and dispatch positions given the participation of VLPs in the market.
- **Suppliers**, who will face costs of socialised compensation under one of the P415 compensation variants.

Our impact assessment module will bring together all elements of the analysis to provide several outputs. This will include an overall net present value estimate of social welfare, consumer welfare, producer surplus and CO2 emissions. Our analysis will also enable targeted analysis of the potential impacts on the revenues of VLPs participating in the market.

Benefits

We use CEPA's wholesale market model to assess the impact of P415 on wholesale market prices and carbon emissions. Drawing on the outputs from the model, we will also estimate the impact of P415 on requirements for the level of generation capacity needed to meet system demand.

We will consider two other potential benefits through engagement with key stakeholders, informed to some degree by the findings of our modelling. P415 Workgroup members have told us that there may be positive externalities from the participation of VLPs in the wholesale market – i.e., that it will result in VLPs having access to greater flexibility in the balancing markets as well. We will test this hypothesis through engagement with the electricity system operator (ESO), seeking to understand the potential order of magnitude of such benefits given the volume of VLP participation that we observe in the wholesale market.

Workgroup members have also suggested that participation of VLPs could reduce the need for network capacity given the reduction in demand during system peak. We will test this hypothesis through engagement with network companies.

Costs

As well as benefits, we will assess the potential range of costs of P415. These include direct financial costs that would fall on industry stakeholders, both to implement the P415 solution and to maintain the processes, systems and information provision required. We will also consider the potential for unintended consequences of the modification on market participants and on consumers. Both types of costs will be explored through a 'call for evidence', in which we will seek evidence-based input from Workgroup members and wider interested industry participants.

2.1. Analysis of benefits

We provide further detail on our assessment approach for each of the five key benefits below. We will also consider the potential for a range of wider potential benefits that have been informed through discussion with the Workgroup (see Section 2.1.4). The analysis of these wider benefits will be based on secondary sources of evidence, e.g., considering case studies, academic research, trials and our own economic appraisal. Results from the modelling will support this assessment where relevant.

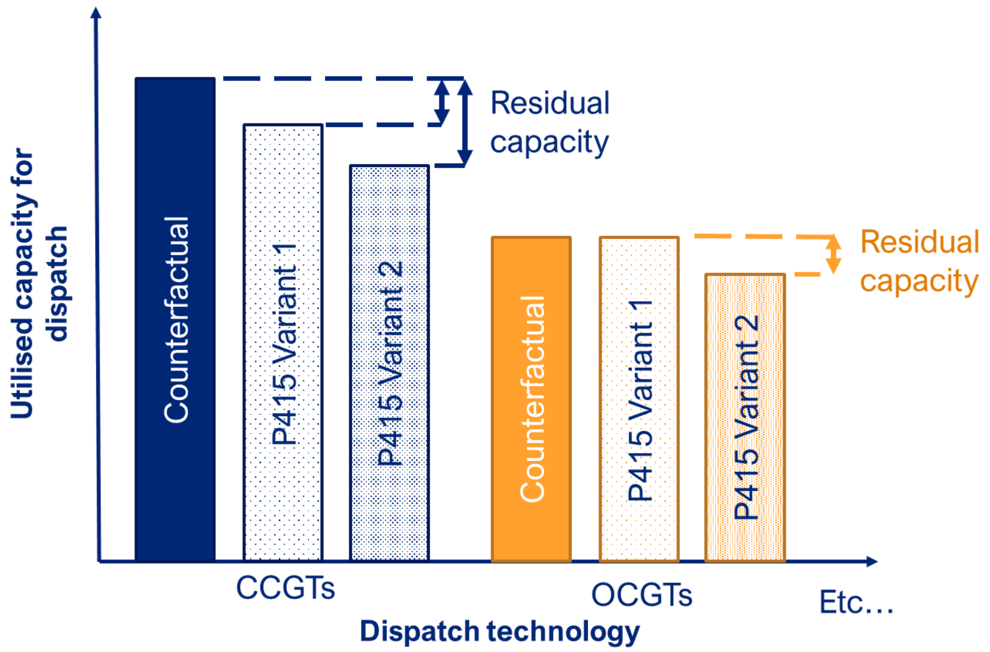
2.1.1. Wholesale market impacts, carbon emissions and generation capacity requirements

Our model will generate hourly wholesale market dispatch, day-ahead market (DAM) prices and carbon emissions, with and without participation of aggregators in the wholesale market. This will allow us to determine the differences in the DAM price between the P415 variants and the counterfactual as a direct output from the model. Section 3 provides further detail on our modelling framework.

Analysis of the requirements for generation capacity will require some post processing of modelled outputs. We will model the installed capacity of each technology based on data under three scenarios. This installed capacity profile will be the same under each option and the counterfactual. Based on our modelling, we will measure the 'residual capacity[1] of each technology that is not required to meet demand during any hour within the year. In the case that the P415 modification allows for a reduction in the need for generation capacity needed to meet demand, we will observe this through an increase in the level of residual capacity that is included in the model, but which is not dispatched. Relative to the baseline capacity of each technology in the model in the initial spot year (2024), we will define avoided residual capacity that is avoided entry of new capacity and avoided residual capacity that represents exit of existing capacity. We will value avoided entry at the estimated capex for the relevant technology, while valuing exit of capacity at the fixed and variable operating costs.

[1] Accounting for de-rating of capacity where relevant

Figure 2.2: Measurement of residual generation capacity under P415



2.1.2. Balancing market impacts

We have engaged with the Workgroup to understand the potential mechanism for benefit in the balancing market. We presented them with two potential mechanisms:

1. **Positive externalities**: Additional revenue opportunities will increase volumes of VLP aggregation in the market. This will have positive externalities for volumes and prices delivered in the balancing market.
2. **Imbalance reduction**: Additional volume of flexible VLP aggregation in the wholesale market will generally work in the opposite direction to the imbalance position. Therefore, this activity will tend to reduce imbalance relative to the counterfactual.

The Workgroup considered the first mechanism to have the most material impact on the balancing market and therefore suggested that it be the focus of this assessment. The Workgroup also assumed that flexibility delivery in the balancing market would remain relatively small in comparison to the potential delivery of volumes in the wholesale market.

Our market model does not incorporate the balancing market. However, we intend to engage with the ESO to understand the potential for additional volumes of VLP provided DSR to participate in the balancing market. Drawing on the volumes of participation that we observe in the wholesale market model, we will seek to develop an understanding of the order of magnitude of the possible costs reductions that may be observed as a result.

2.1.3. Network impacts

Our assessment of potential impacts on networks and network operation will be developed through engagement with network companies. We will draw on their knowledge and expertise to consider the interaction between flexible demand, network capacity and network operation. There are several questions that we wish to test with network companies to get a sense of the potential order of magnitude of such impacts:

1. To what extent will networks be able to build potential VLP volumes into peak network planning and defer/avoid reinforcements by 2034 (i.e., within the next two price control periods)?
    a) Given necessary risk aversion in network security standards, would this result in a material reduction in network capacity planning?
2. Could there be positive externalities of greater VLP participation in meeting the flexibility procurement needs of DSOs and/or the ESO?

3. Are there any potential **cost** impacts on networks to manage greater localised flexibility/volatility of demand and dispatch for DSOs and/or the ESO?

We would not expect P415 to result in any direct locational benefit in the wholesale market given the system-wide nature of the day-ahead market in GB. Our analysis of network reinforcement impacts will therefore focus on the potential for a reduction in capacity requirements due to 'whole system' reductions in capacity needs, for example at times of peak demand.

2.1.4. Wider impacts

In parallel with our quantitative analysis of the key benefits, we will also develop an evidence base for several wider potential benefits that will be considered qualitatively. Following engagement with the Workgroup, we intend to consider the following potential benefits:

- **positive externalities** of additional DSR availability for CM prices (where additional to capex benefits of capacity reduction) and wider system services[2];
- **security of supply** and resilience from diversification of the market;
- benefits related to **consumer engagement and satisfaction;**
- providing **choice** and **competitive pressures** for customers looking to provide flexibility in the wholesale market;
- additional source of DSR which can support **distributed energy and renewables integration**;
- additional source of DSR which can support **electrification** of heat and transport; and
- benefits in the **supply chain** for demand side response services and products.

Wherever possible we will seek to develop an informed sense of the potential order of magnitude of impact through assessment of international case studies, stakeholder engagement, academic research and experiments/trials regarding DSR and aggregator participation. Where not possible, we will aim to set out a clear mechanism for the anticipated benefit and consider the conditions under which the benefit is likely to materialise or not.

2.2. Analysis of costs

We will consider two types of cost of implementing P415, direct financial costs and unintended consequences. Assessment of both types of cost will be supported by a 'call for evidence' used to gather views from stakeholders. Our assessment of unintended consequences will also incorporate our own economic and policy appraisal, drawing on secondary sources of evidence and results from our modelling where relevant.

2.2.1. Financial costs on industry participants

We will estimate the direct financial costs falling on the range of impacted industry participants. This will include the financial costs of implementing P415, e.g., given a need for changes to systems, processes and information provision. It will also include any ongoing costs to maintain such systems and processes.

Our engagement with the Workgroup has identified a range of possible financial costs of P415 as set out in Table 2.1:

[2] Care needs to be taken not to double count externalities across multiple markets.

Table 2.1: Initial views on direct financial costs of P415

Affected industry participant	Implementation costs	Ongoing costs	Workgroup views
BSCCo	Introduction of new processes, systems, data collection and handling	Maintenance of new processes and systems	Workgroup expected the costs to the BSCCo to be the most significant
Virtual Lead Parties	Setting up systems to communicate wholesale market positions and provide data to BSCCo	Maintenance of systems and ongoing processes to provide data to BSCCo	Workgroup expected costs to VLPs to be the most significant after BSCCo costs
Suppliers	None expected	Depending on compensation mechanism (see Section 3.7), may be liable for socialised compensation	Workgroup did not expect any costs to suppliers other than from the compensation variant
NGESO	NGESO has indicated that changes to their systems will be needed. They have undertaken a project to understand these impacts better	NGESO has indicated that changes to their systems will be needed. They have undertaken a project to understand these impacts better	Workgroup did not expect significant financial costs for the NGESO. However, this will be explored directly through engagement with the NGESO
Network companies	None expected	Workgroup did not expect significant financial costs for the NGESO	Workgroup did not expect significant financial costs for network companies

2.2.2. Unintended consequences

Alongside direct financial costs we will consider the potential for unintended consequences of P415. This will include consideration of:

- Impacts of socialised compensation on suppliers.
- The potential for VLP participation in the wholesale market to replace participation in other markets – i.e., displacing flexibility that would have been provided elsewhere.
- The potential for additional complexity and consumer confusion as VLPs enter the market and compete with suppliers for flexibility provision.
- Risk of non-delivery of electricity demand side reduction volumes, potentially undermining benefits relating to generation and network capacity savings and/or introducing the need for risk premiums on this form of flexibility. We note that financial penalties exist for such non-delivery and will consider the extent to which these penalties would alleviate this risk.

2.2.3. Structure of the Call for Evidence

We will work with Elexon to develop a Call for Evidence which allows industry participants to provide a range of cost estimates for implementation and ongoing costs. To ensure consistent and clear provision of data from the industry we will accompany the consultation with a cost submission template. We will publish the consultation document on Elexon’s website and notify stakeholders through Elexon’s communication channels. We assume that all consultation responses will be published on Elexon’s website unless marked as confidential.

Workgroup members stressed the challenges envisaged with providing evidence-based cost assumptions. We will encourage market participants to provide high, medium and low-cost estimates along with background information which allows us to extrapolate from a sample of responses to a market wide estimate. We will also emphasise the importance of providing a robust evidence base to support estimates, for example drawing on experience of implementing prior modifications or on bottom-up analysis of implementation costs. We will weight submissions that include a stronger evidence base more heavily when we appraise the submissions and draw on wider evidence to benchmark cost submissions where possible.

3. MODELLING FRAMEWORK

We will perform wholesale market modelling to assess three of the key benefits as well as to develop analysis of the distributional impacts. In this section, we provide further detail on the structure of the model, our choice of scenarios and the assessment period.

3.1. MODEL STRUCTURE

We will use CEPA's proprietary wholesale market model to perform this assessment. Our model is 'deterministic' and simulates day-ahead market prices for the GB wholesale market. For this task, we will set up our wholesale market model as follows:

- **A single GB market with no zonal configuration**: We will capture network reinforcement impacts outside of the model and we are not considering impacts on network constraints or constraint actions by the ESO. We therefore focus modelling on a national representation of the wholesale market where the direct impacts of P415 are expected to be the most significant.
- **Endogenous dispatch, demand and price formation**: In Section 3.1.1, we set out the range of generation and demand technologies that we will include in the model. We will allow dispatch and demand to vary in response to the wholesale electricity price which is itself determined by the interaction of supply and demand curves. The exception is where there is good reason to assume that dispatch and/or demand profiles are generally independent of prices (e.g., for non-dispatchable renewable generation, nuclear generators and inflexible demand), This endogeneity allows us to consider the impacts on dispatch and wholesale market prices under the P415 variants in comparison to the counterfactual.
- **Hourly granularity with sample 'spot years'**: We include hourly resolution of the wholesale market with modelling of dispatch, demand and DAM prices across 8760 hours in each calendar year (24 hours a day for 365 days of the year). We will model the wholesale market in three spot years within the timeframe of assessment (see Section 3.3). This will allow for sophisticated analysis of mechanisms for impact. We will interpolate the assumptions and analysis between these years to allow for assessment of the costs and benefits over the full period
- **Carbon emissions impacts**: Each technology in our model has an associated carbon intensity which will be defined based on publicly available sources. From this, we will calculate the carbon intensity of dispatch under each scenario and option. To incorporate these estimates into the overall CBA we will monetise carbon emissions at the social cost of carbon in line with Government guidance[3].

3.1.1. Generation and demand archetypes

Our model includes a detailed set of generation technologies and demand archetypes (approximately 24 generator and 12 demand types) across the transmission and distribution networks (Figure 3.1 and Figure 3.2). Each generation technology is modelled as a single fleet across the market with dispatch based on the technical characteristics and variable costs of each representative dispatch type.

For the demand archetypes, the model includes assumptions which represent the responsiveness of demand side customers to wholesale electricity market prices. We will also introduce the provision of flexibility from this set of customers which is delivered by VLPs under P415. We discuss this in detail in Section 0.

[3] See: https://www.gov.uk/government/collections/carbon-valuation--2

Figure 3.1: Generation and storage technologies included in the model at transmission and distribution level

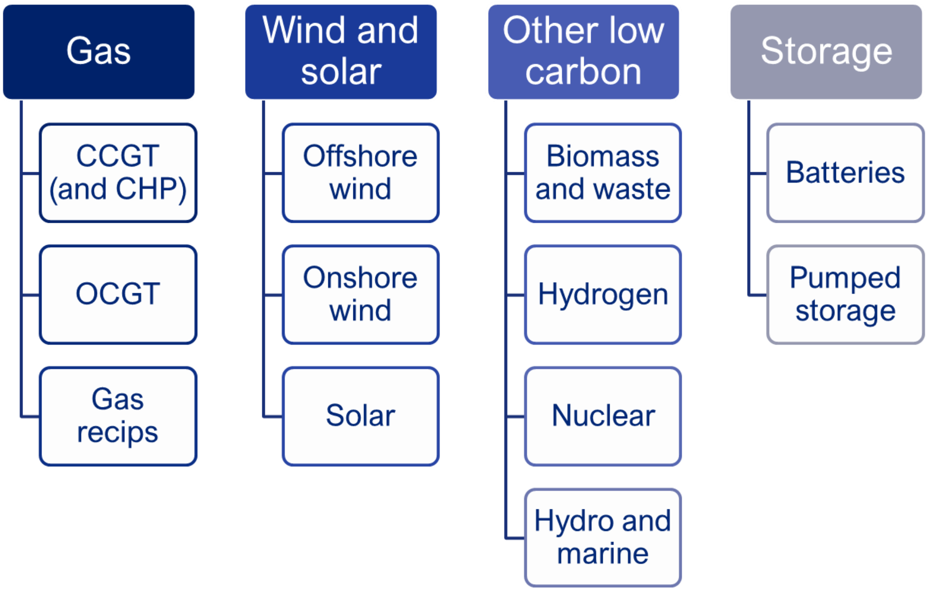
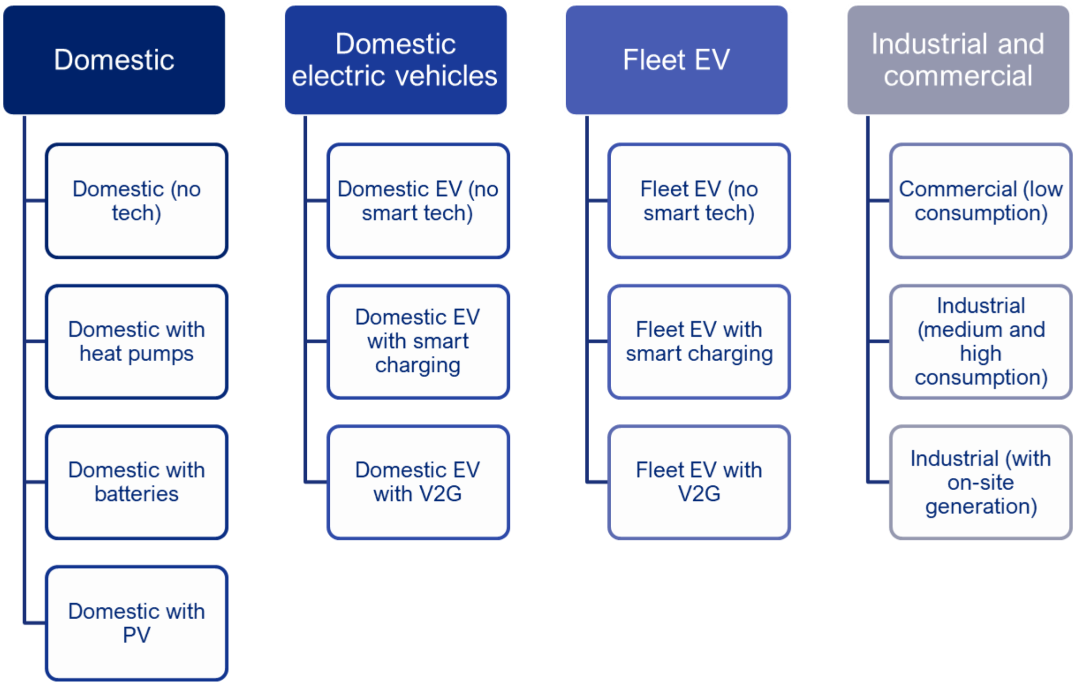


Figure 3.2: Consumer archetypes represented in the model

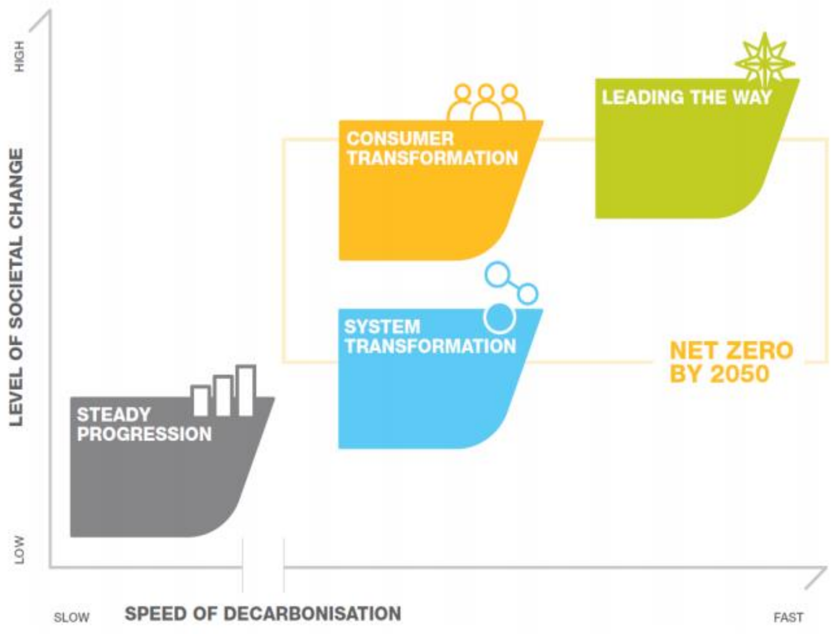


3.2. Scenarios

To test the potential impacts of P415 against multiple potential 'future worlds', we will draw on National Grid's Future Energy Scenarios, 2021 (FES)[4]. The FES are well-established, publicly available scenarios developed with the help of intensive stakeholder engagement. The scenarios differ in two dimensions: the speed of decarbonisation of energy sources, and the level of societal change. The speed of decarbonisation will affect the value of flexibility in the model while the level of societal change generally reflects decentralisation and the extent of flexibility provided by consumers.

[4] https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2021

Figure 3.3: FES 2021 scenarios



Source: National Grid

Drawing on multiple scenarios from the FES will allow for consideration of how impacts of P415 may change depending on factors such as demand growth, generation deployment, etc. Most importantly, using multiple FES scenarios will allow us to consider the impacts of P415 based on a range of assumptions regarding the take-up of demand side flexible technologies.

To capture a high, medium and low estimate of benefit we will draw on three FES scenarios. We will model impacts against the 'Consumer Transformation' scenario as a central estimate, in addition to high and low decarbonisation scenarios based on 'Leading the Way' and 'Steady Progression' scenarios respectively. 'Consumer Transformation' provides a high electrification, decentralised scenario in which 2050 decarbonisation objectives are met with a high level of societal change. 'Leading the Way' represents the fastest possible decarbonisation scenario identified by National Grid while 'Steady Progression' represents the slowest possible decarbonisation scenario. Therefore, the use of these scenarios provides useful high and low stress tests around the central scenario regarding the value of flexibility and take-up of flexible technologies.

While most input parameters will be taken directly from the relevant FES scenario as inputs into the model, we will develop our own assumptions for the level of flexibility provided by different consumer technologies[5], both with and without VLP participation in the wholesale market. We discuss the development of these assumptions in more detail in Section 0.

3.3. Assessment period and spot years

Elexon specified a time horizon for the CBA of 10 years. We agree that this represents a sensible appraisal period as there may be several market designs, technological and societal changes beyond this period that introduce an additional level of uncertainty as to the costs and benefits of P415.

[5] As a result, outputs from the modelling may not be fully consistent with the FES.

November 2022 is the earliest possible date for implementation of P415[6]. However, due to large volumes of industry change and the complexities associated with P415, we understand that it is unlikely to be implemented before 2024. In addition, we anticipate the need for VLP business models to ramp up their activities in the wholesale market before they can deliver volumes of DSR at scale. For these reasons we intend to model 2024 as the initial spot year of the analysis. In line with the 10-year modelling horizon, 2033 would therefore represent the final year of the assessment. To allow for effective interpolation between these two years, the most appropriate spot year for assessment in the middle of the period is 2029[7].

3.4. Flexibility provision

Our modelling will incorporate the provision of flexibility from the relevant consumer types included in Figure 3.2, even under the counterfactual. This flexibility will represent the responsiveness of small residential and commercial consumers with flexible technologies to flexibility enabled directly by suppliers and direct contracts by suppliers of large, flexible loads.

Take-up of each flexible technology under each scenario will be taken directly from the FES. We will develop assumptions for the demand profile of each technology, drawing on historical data for each customer type. We will incorporate a profile of flexibility designed to reflect the demand profile of the relevant consumer archetype and the nature of flexibility provided. For example, the flexibility provided by electric vehicle (EV) users with smart chargers will be significantly higher than EV users with no additional technology and the level of flexibility will change in each hour, reflecting the expected demand profile of EVs. E.g., there will be more potential for flexibility provision during evening peaks as consumers return home and plug in EV chargers.

We will model two distinct forms of DSR:

- **'Load shifting'** implies that any demand reduction is balanced by an increase in demand in other periods. In our model this type of response is modelled as a 'storage' unit.
- **'Peak reduction'** implies that any demand reduction is not balanced by an increase in other periods. This may reflect load that can be met with alternative back-up generation for example. In our model, this type of response is modelled as a 'generator' unit at the demand node which nets off demand.

Based on engagement with the workgroup we intend to model flexibility provision from EVs and batteries as load shifting. We heard from one workgroup member that heat pump use may represent peak reduction however we will test this further before finalising our assumptions for this type of load.

We will model two classes of large industrial and commercial flexibility. The first will represent load shifting where we assume that industrial processes can be shifted between periods or can be modified for short periods without any notable effect on output. The second will represent peak reduction where consumers would be compensated for lost output or may have alternative means of production (e.g., on-site generators) that allow production to continue largely unaffected.

In the model, DSR will effectively compete with generation in the wholesale market merit order, with variable costs defined for different types of load (see Section 3.6.1).

3.5. 'Additionality' of VLP provision

Under the P415 options, VLPs will provide an additional source of flexibility from each consumer technology archetype. This may represent the additional capacity of each consumer technology which enters into flexibility agreements relative to the counterfactual. It may also represent the potential for VLPs to deploy flexibility more effectively into the wholesale market.

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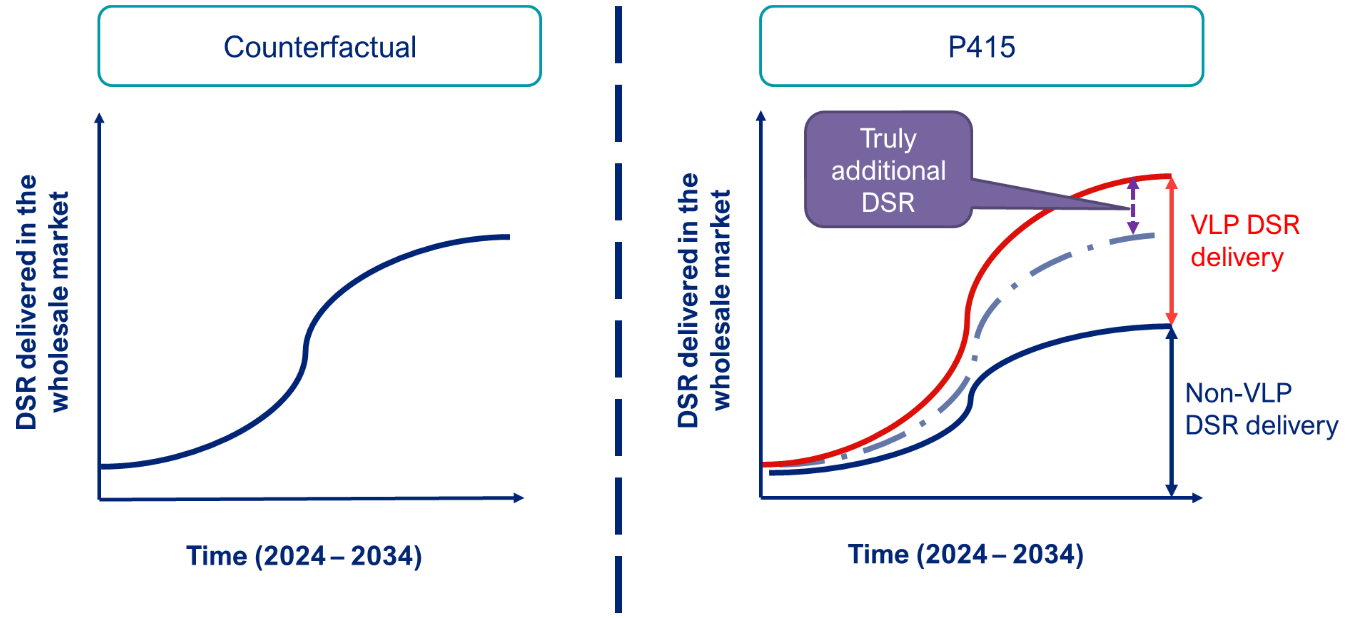
[6] See p. 4, https://www.elexon.co.uk/documents/change/modifications/p401-p450/p415-initial-written-assessment/

[7] Depending on evidence of model run-time following testing, we may choose to model four spot years with 2028 and 2031 chosen to represent intermediate years in the analysis.

As part of our CBA, we must consider the extent to which flexibility provided by VLPs would have been delivered even if P415 had not been implemented (Figure 3.4). Under the counterfactual, some proportion of DSR delivered by VLPs may have provided flexibility through alternative arrangements, such as direct contracting of customer flexibility by suppliers, or in response to time-of-use tariff designs.

Figure 3.4: Measuring the 'additionality' of VLP provision



The extent of additionality of VLP provision during the period 2024 – 2033 will be highly dependent on factors including VLP business models, the success of non-VLP flexibility models for developing flexibility with customers in the absence of P415 and the nature of flexibility in the market.

To capture the full range of potential future outcomes, we intend to vary our assumptions of additionality between the three FES scenarios. This will allow us to test whether the benefits of P415 outweigh the costs under a 'worst case', 'central case' and 'best case' scenario of VLP flexibility provision. We will develop further analysis to identify a set of additionality assumptions that reflect this range appropriately.

Table 3.1: 'Additionality' assumptions applied to each FES scenario

	Additionality		
	Low	**Medium**	**High**
Steady Progression	'Worst Case'	Not included	Not included
Consumer Transformation	Not included	'Central case'	Not included
Leading the Way	Not included	Not included	'Best case'

3.6. VLP DEFINITION

To incorporate VLPs into the model we will attach an additional 'storage unit' or 'generator' to each consumer archetype (Figure 3.2) depending on whether we assume they provide load shifting or peak reduction respectively. In each case, the first storage/generator unit will continue to represent flexibility provided through mechanisms other than VLPs while the second storage/generator unit will represent VLP-delivered flexibility.

The capacities and technical parameters of both the VLP and non-VLP storage/generator units will be adjusted to reflect the assumptions of flexibility provision and 'additionality' that we assign to each form of flexibility.

3.6.1. VLP cost assumptions

VLPs will incur fixed up front and fixed ongoing costs to deliver volumes of flexibility, e.g., to acquire and manage a customer portfolio. Workgroup members also say that in many cases they expect to incur the costs of installing enabling technology (e.g., 'smart' thermostats, 'smart' EV chargers, industrial process automation) to allow for flexibility to be delivered. In some cases, we may assume that variable costs of delivering flexibility are low, in particular where customers observe little/no impact on their electricity supply. In other cases, VLPs will also incur variable costs associated with compensating customers for inconvenience associated with the provision of flexibility.

Our model will incorporate the variable costs of delivery as an additional cost of the provision of flexibility in each hourly period. While fixed costs will not feature directly in the model, we will compare revenues recovered by VLPs against these fixed cost assumptions to provide commentary on the likelihood of entry and exit of VLPs, considering the feasibility of revenues that would need to be recovered from other markets.

To inform our consideration of the cost base of VLPs we submitted a data request to members of the Workgroup requesting their views on cost assumptions for three types of aggregator. Combined with our own analysis, we have developed the following assumptions:

Table 3.2: VLP cost assumptions

	Residential customers[8] - load shifting and peak reduction	Industrial and commercial – load shifting	Industrial and commercial – peak reduction
Up front fixed costs (£/MW)	Similar customer acquisition costs to a supplier + fixed costs of enabling technology	C. £2.5k - £6k/MW	C. £2.5k - £6k/MW
Ongoing fixed costs (£/MW/yr)	Similar costs to serve to a supplier + enabling technology operation and maintenance	C. £1.2k - £5k/MW/yr	C. £1.2k - £5k/MW/yr
Variable costs (£/MWh)	~£0 (assuming minimal disruption for the flexibility provider)	~£0 (assuming minimal disruption for the flexibility provider)	Multiple tranches: 1st tranche: c. £50/MWh … Nth tranche: c. VoLL – 10%

3.7. Compensation variant definition

We will assess the costs and benefits under two variants of P415 which differ in the way in which suppliers are compensated for lost volumes delivered into the wholesale market. The definition of these two variants and the modelling approach used is designed to reflect the Workgroup's position. We summarise the intended approach for modelling each variant in Table 3.3.

[8] NB: We intend to carry out analysis to develop assumptions for customer acquisition costs, costs to serve and technology costs to incorporate into the model.

Table 3.3: Modelling of compensation variants

Variant	Who pays?	Compensation price	Analytical approach
Proposer	VLPs	Estimate of supplier sourcing costs to approximate retail price (The methodology is being developed by Elexon)	We will incorporate compensation into the model as an additional variable cost to VLPs of providing volumes into the wholesale market. The sourcing cost methodology may need to be approximated, for example as a fixed discount on a historical spot price derivation.
Alternative	Socialised across all suppliers	Wholesale market spot price	We assume that the socialised cost of compensation has a negligible impact on the marginal costs of wholesale market volumes. Therefore, it is not incorporated in the model. However, we will estimate the total level of socialised compensation based on volumes of VLP participation and the associated spot price in each period.

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