# Access SCR Impact Assessment Modelling Methodology

Ofgem

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**TECHNICAL ANNEX**

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# Contents

# 1. HIGH-LEVEL MODELLING FRAMEWORK

Our approach combines several models, some of which have been developed under this contract, and others which have been developed separately. Together, these models are used to calculate the net present value (NPV) impacts of Ofgem's charging reform options on the wholesale market and on network reinforcement costs. The modelling framework is also used to estimate impacts on different network users, in different locations and at transmission and distribution voltage levels.

At a high level, the process is as follows:

- **Cost models** developed for the distribution network by the Energy Networks Association (ENA) are used to calculate the unit costs of capacity expansion at different network locations.
- A combined low voltage (LV), high voltage (HV) and extra-high voltage (EHV) network distribution use of system **(DUoS) charging model** uses these unit cost inputs to calculate a set of distribution network charges for key user archetypes at different network locations within each distribution network operator (DNO) network, under each DUoS charging option.
- A transmission network use of system **(TNUoS) charging model** calculates a set of transmission network charges for generation and demand users at different network locations, under each TNUoS charging option.
- CEPA's **wholesale market model** takes the range of network charges and incorporates them into its generation and demand cost functions to optimise for a least cost solution given a set of constraints. The model also includes behavioural responses for different user archetypes, modelled through demand elasticities in relation to network charges and to wholesale market prices.[2]

  We run two versions of the wholesale market model:

  - An 'unconstrained' version of the market model, which simulates the day-ahead market (DAM). This estimates the impacts of each option on the DAM price, on the generation or consumption of different types of users, and on the locational investment decisions of a set of new generation/other low carbon technologies across distribution and transmission network zones.[3]
  - A 'constrained' version of the market model, which reflects transmission network capacity limits between seven key transmission zones. By incorporating unit costs of network capacity expansion, it also estimates costs of transmission network reinforcement. However, it is important to note that **we do not model the transmission network at the level of detail included in the transport model** owned by the electricity system operator (ESO).
- The **distribution network model** then takes generation and demand outputs from the market model, inclusive of behavioural responses. Based on the locational allocation of different technologies and the level of behavioural response in each distribution network zone, the distribution reinforcement model estimates the impacts of the options on the need for, and costs of, distribution network reinforcement.

  The model also includes an alternative to network reinforcement for DNOs, based on a simplified representation of DNO contracted flexibility services.

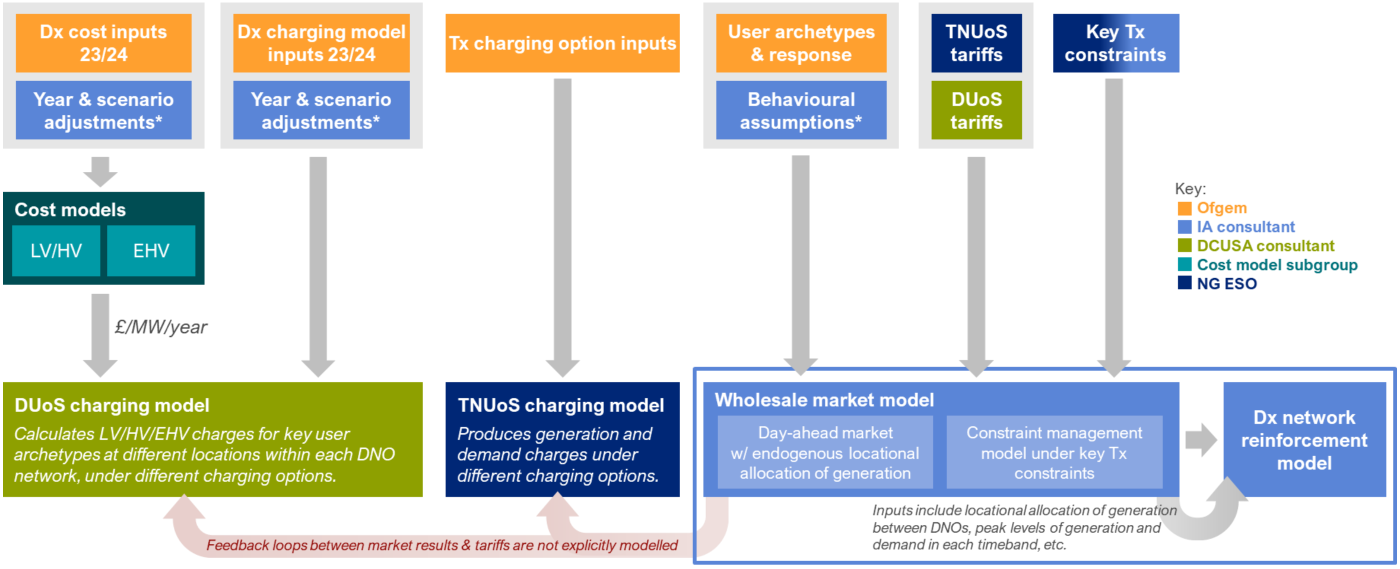
[2] We have developed assumptions on behavioural responsiveness based on our literature review and calibrated these based on an initial 'dummy' run of the wholesale market model. These behavioural assumptions feed into the wholesale market model to ensure that consumers respond to network charging signals provided by each of the policy options.

[3] See section 2.3.2 for more details on our approach to modelling the locational allocation of different technologies.

- Outputs from the market model and distribution network model are combined in an **impact assessment model** to produce an NPV of charging policy impacts.

Figure 1.1 provides a representation of our high-level modelling framework, including key inputs or decisions and relationships between individual models. We also summarise the owners of inputs/models that feed into our own analysis from other parties.

*Figure 1.1: High-level modelling framework flowchart*




*Calibrated using a dummy run of the wholesale market model

## Modelling horizon

Modelling is conducted for the period 2024-2040. Different models in our framework take a slightly different approach regarding representation of the full modelling horizon, depending on their purpose and the impacts they were developed to capture.

The cost models and the DUoS charging model utilise inputs primarily from the ESO, DNOs and other published sources of short-term forecasts to produce charges for each policy option for financial year 2023/24. This data is unavailable for future years, so we rely on extrapolation to determine unit costs and charges out to 2040/41. Our extrapolation approach is based on expected growth rates of peak generation and peak demand in different timebands using a 'dummy' run of the market model under the counterfactual for each modelled scenario.[4] In addition to the first and last spot year, we also model the spot year 2028/29, using the same extrapolation approach.

The TNUoS charging model takes a similar approach for producing 2023/24 tariff outputs for each charging option. The ESO adapted the TNUoS charging model, to produce tariff for the 2040/41 financial year based on the FES 2019 Two Degrees scenario. Tariff outputs were not explicitly produced for 2028/29 – instead, we used a simple interpolation approach to estimate tariffs for that year.

The wholesale market model focuses on three spot years: 2024, 2029 and 2040.[5] Decisions taken in earlier years (e.g., the locational allocation of a given technology in a given network zone, or an increase in transmission network

[4] The dummy runs for each modelled scenario are three initial runs, using the 2023/24 counterfactual tariffs (which are assumed to remain flat for all three years). These market model simulations are then used for extrapolating the tariffs more appropriately over our modelling horizon, based on expected growth rates of peak generation and peak demand in different tariff timebands.

[5] Note that due to data availability we take the generation and demand capacity mix for the market model from the FES, which utilises calendar years. We match calendar year 2024 to the financial year 2023/24, which allows us to model the generation mix following scheduled closure of coal plants. Similarly, we match calendar year 2029 to the tariffs for the financial year 2028/29 – but we use tariffs for financial year 2040-41 for calendar year 2040.

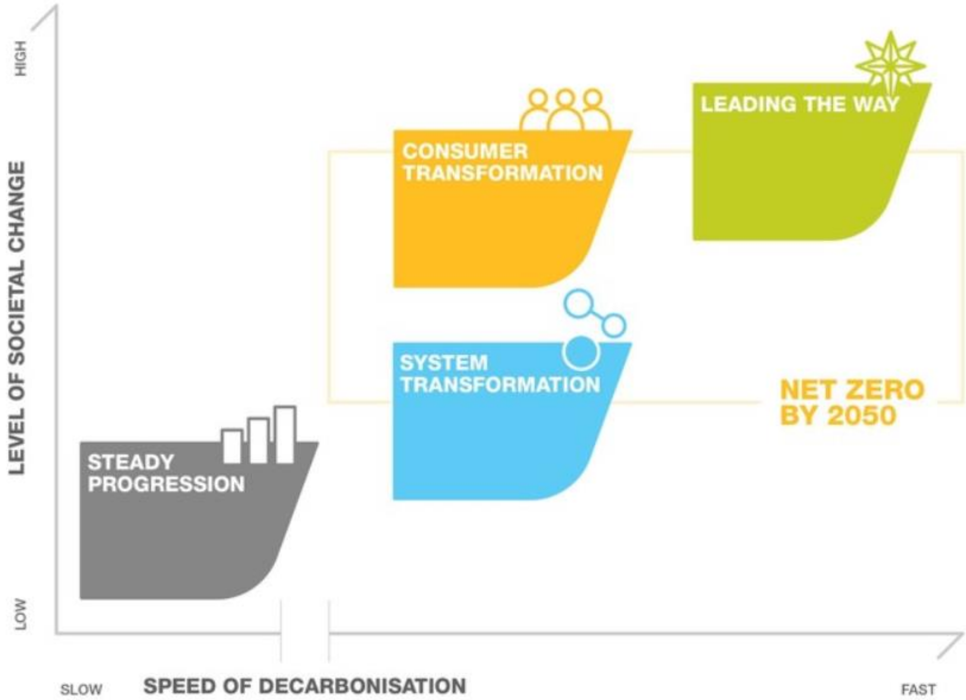
capacity reinforcements) are reflected in later years, ensuring the modelling is consistent across the entire modelling horizon. We interpolate between spot years to estimate NPV impacts over the full period in the impact assessment model.

The distribution network model focuses on the four five-year RIIO periods spanning our modelling horizon, i.e., 2023-2027, 2028-2032, 2033-2037, and 2038-2042. This allows for a fuller representation of how signalling reinforcement costs through connection charges changes users' choices about where to locate their capacity within each DNO network. This is then factored into the level of distribution network reinforcement needed after incorporating behavioural responses to charging signals.[6] In the impact assessment model, we then discard 'excess' individual years (i.e., years before 2024 or beyond 2040) to estimate NPV impacts over a consistent 2024-2040 modelling period.

## Scenarios

We use the FES 2020 scenarios in our modelling. The FES 2020 includes the scenarios set out in Figure 1.2 below:

*Figure 1.2: FES 2020 scenarios*




*Source: National Grid ESO*

The FES scenarios vary in two dimensions – the speed of decarbonisation and the level of societal change:

- The Consumer Transformation (CT) and System Transformation (ST) scenarios deliver Net Zero decarbonisation commitments. Of the two, CT is more decentralised and achieves Net Zero through a more significant level of societal change and with a greater adoption of electrified consumer technologies.
- Steady Progression (SP) makes progress towards net zero objectives but does not meet them. Under SP, the level of societal change and decentralisation are lower than under both CT and ST.
- Leading the Way (LW) goes beyond the Net Zero targets. The level of societal change and degree of decentralisation under LW is broadly similar to the level of change assumed for CT but occurs at an accelerated pace.

[6] See section 2.3.3.

Ofgem set out two key objectives for the choice of modelling scenarios:

1. Testing costs and benefits under a plausible range of scenarios.
2. Assessing the contribution/impacts of reforms in enabling/hindering certain pathways.

We identified the CT scenario as the most effective test of the second objective. The policy options are intended to provide signals which are likely to contribute to societal change and to support delivery of an ambitious decarbonisation agenda. **We use the CT scenario as our central scenario for analysis.**

We run the SP and LW scenarios as alternative backgrounds on CT. This allows for consideration of the impacts of policy reforms under a wide range of potential future outcomes, thus allowing Ofgem's first objective to be met more effectively. While SP may represent an undesirable future world, it provides an important 'stress test' of potential benefits.

**Box 1: How we use scenarios in our modelling**

We rely on the FES scenarios for several key inputs into our impact assessment models for each spot year and scenario. For example:

- Installed capacities of different types of storage and generation technologies,
- The proportion of installed capacity of different technologies on the transmission and distribution grid,[7]
- The levels of installed capacity of different technologies in different network zones, both at transmission[8] and distribution level,[9]
- Interconnection capacity,
- GB electricity demand for different types of consumers, including by distribution zone where relevant,
- Take up of consumer technologies (e.g., heat pumps, electric vehicles, smart charging and V2G, etc.), including by distribution zone where relevant, [10]
- Pass through rates of time-of-use (ToU) tariffs,
- Carbon prices, and,
- Global energy supply and demand and global commodity prices.[11]

[7] We adjust this proportion to exclude distribution-connected generators with capacity of greater than 100 MW and a bilateral embedded generation agreement (BEGA) from the capacity labelled as transmission-connected in the FES. This adjustment is intended to help us better represent the different categories of generators from a tariff application perspective. See sections 2.3.2 and 2.3.4 for more detail.

[8] Based on confidential data shared by the ESO for the purposes of this impact assessment.

[9] Note that for the majority of renewable technologies, we do not directly utilise levels of installed capacity by network zone. Rather, we use these inputs to define upper and lower bounds for each zone around the regional breakdown included in the FES and allow the model to endogenously optimise the location decision for that technology subject to those bounds and the total level of installed capacity. See section 2.3.2 for further details.

[10] Note that for some consumer technologies, we do not directly utilise take-up levels by network zone. Rather, we use these inputs to define upper and lower bounds for each zone around the regional take-up breakdown included in the FES. We then allow the model to endogenously optimise which consumers take up which technologies (and at what rate) subject to those bounds and the total level of take up across GB. See section 2.3.3 for further details.

[11] We rely on the corresponding IEA World Energy Outlook (WEO) scenarios to map against the FES scenarios. For example, we identify the WEO 'Sustainable Development' scenario as correlating most closely with net-zero-compliant FES scenarios: *"The Sustainable Development Scenario maps out a way to meet sustainable energy goals in full, requiring rapid and widespread changes across all parts of the energy system."*

# 2. MODELLING ARCHITECTURE

## 2.1. Cost models

A combined LV, HV and EHV distribution network cost model has been developed by the ENA cost model subgroup and has not been in scope of this project. The cost model calculates the unit costs of expanding the distribution network at different network locations, under alternative cost concepts. These unit costs feed into the DUoS Charging Model to establish the set of DUoS charges. This note does not go into detail on the design of the cost models.

The cost model utilises inputs primarily from the ESO, DNOs and other published sources of short-term forecasts to produce unit costs under each policy option for our first spot year, i.e., financial year 2023/24. Unit costs for later spot years are extrapolated from the 2023/24 values, based on expected growth rates of peak generation and peak demand in different timebands and their impact on modelled peaking probabilities for different users at different locations within each DNO network.

These expected growth rates are derived from an initial 'dummy' run of the market model for each modelled scenario, under the counterfactual (i.e., in the absence of tariff changes).

### Outputs from the LV, HV and EHV cost models

- Unit costs[12] at different network locations, under approaches for defining unit costs of expansion.
- Peaking probabilities,[13] used to set charges at LV and HV in the counterfactual.

## 2.2. Charging models

### 2.2.1. DUoS charging model

The DUoS Charging Model has also been developed separately to this project. It includes around 500 locations/primaries per DNO and has been designed to model the counterfactual tariff regime, after inclusion of the Targeted Charging Review outcomes. It is also designed to incorporate DUoS options packages and variants that have been developed by Ofgem as part of the Access SCR review to date.[14]

The DUoS Charging Model produces DUoS tariffs for a range of users for 2023/24, using inputs from the network cost models and published CDCM models. Charges in 2028/29 and 2040/41 are estimated by updating values which would evolve as demand and generation change over time. These inputs are calculated in the Cost Models described above.

The DUoS charging model provides tariffs inputs into the market model and the Distribution Reinforcement Model.

[12] Allocative unit costs, as calculated in the reference network model, express the asset-related cost of providing capacity as the annuitised Modern Equivalent Asset Valuation (MEAV) of assets at each voltage level (£/year) divided by their rating (MVA). This value varies by location but should be stable from year to year. The annual unit cost for each network level is apportioned across timebands as a function of estimated net peak load to give £/MVA/timeband unit costs.

[13] Peaking probabilities reflect the estimated probability of net load peaking in each timeband at each network level. The cost model contains data for peaking probabilities that differs between DNOs. We note that the quality of data in relation to existing peaking probabilities was inconsistent. This meant that five of the 14 DNOs did not have location specific peaking probabilities that could be extrapolated effectively for future spot years. Where this data was not available, peaking probabilities were estimated based on the average of all other DNOs where good quality data was available.

[14] These options were not in scope for this stage of our work.

### Outputs from DUoS Charging Model

- Full set of 2023/24 charges for selected users.
- Set of extrapolated charges for 2028/29 and 2040/41 that feed into the market model.[15]
- Representative outputs from the DUoS charging model, which give, for each tariff, timeband and charge element, the amount contributed to the tariff per £1/kVA/year of unit cost. These feed into the Distribution Reinforcement Model and are used to extrapolate tariffs endogenously over our modelling horizon.[16]

### 2.2.2. TNUoS charging model

TNUoS charges under the different options form another input into the impact assessment.

The ESO has used the Transport Model (DCLF ICRP) to create charges for all 2023/24 and 2040/41. HVDC assumptions are aligned with the NOA and FES 2019. Generation and demand assumptions are based on near-term forecasts for 2023/24 and on the FES 2019 Two Degrees scenario for 2040/41.

Charges for 2028/29 are not provided – rather, we have agreed on a simple linear interpolation approach based on 2023/24 and 2040/41 charges for different users and network locations.

The TNUoS charging model provides TNUoS charges under different charging options as an input into the market model.

### Outputs from TNUoS Model

- TNUoS charges modelled for each spot year under the range of shortlisted options.

## 2.3. Market model

The market model is used for several elements of analysis:

- It simulates DAM prices based on a set of assumptions such as generation supply costs, the generation capacity mix, interconnector capacities and external market prices, as well as expected hourly demand and demand elasticities.
- It simulates responses to price and charging signals from generators and demand consumers, based on endogenous supply cost curves and assumed demand elasticities.
- It allocates generation to different locations, subject to a set of bounds, based on charging signals and (where relevant) resource availability.
- It incorporates a simplified representation of the transmission network such that transmission constraint costs and transmission reinforcement costs across a sub-set of key transmission network boundaries can be estimated. Within the model, these boundaries are fixed over the period of analysis.

### 2.3.1. Modelling different market timeframes

### Day-ahead market

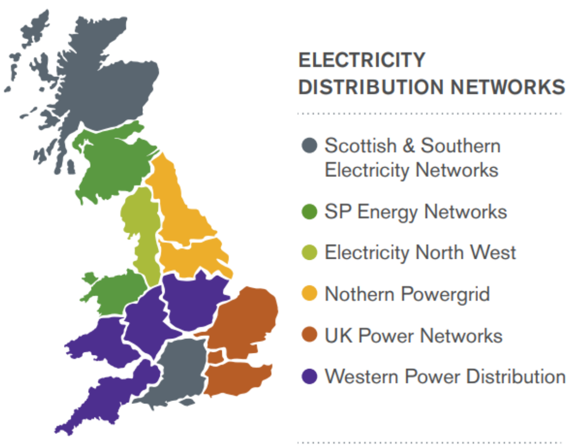
The DAM price and quantities are determined for the system as a whole with no consideration of network constraints from the unconstrained market model run. This market timeframe is represented by a GB-wide deterministic dispatch model.

[15] Note that we do not incorporate exceeded capacity charges or reactive power charges in the market modelling.

[16] See section 2.4 for details.

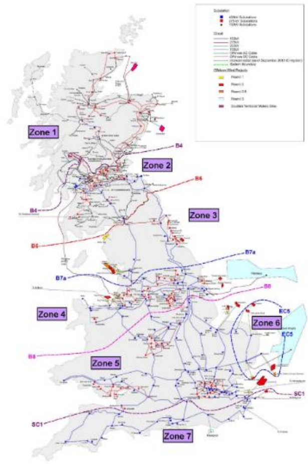
Our market model incorporates dispatch with a number of bespoke features. One of these features is the explicit modelling of the distribution network zones, as well as seven key transmission network zones,[17] illustrated in the figures below. We engaged with the ESO to develop a mapping of existing generation capacity and projected capacity in the relevant FES scenario across our transmission and distribution zones.[18]

*Figure 2.1: Distribution network zones modelled*




*Source: ENA*

*Figure 2.2: Transmission network zones modelled*




*Source: National Grid ESO*

We apply this mapping in several areas:

- **TNUoS charges**: We use the breakdown provided by the ESO. This allows us to apply a weighted average of charges appropriately for each transmission zone represented in our model and apply the TNUoS charges for each distribution zone directly.
- **Transmission losses**: Similar to TNUoS charges – i.e., we use an average for each transmission-connected generation and demand node. Loss factors have been sourced from Elexon and are incorporated into both the unconstrained and constrained model run.
- **Transmission-Distribution Boundaries on the network**: We assume that these are copper plate boundaries in the market model. That is, we do not include capacity limitations or network losses between each transmission and distribution zone.

## Unconstrained model run

To determine a single DAM price, we run a version of the model without any network constraints (unconstrained run). This allows the model to abstract from network constraints, as is the case for nominations in the DAM in practice.[19]

This ‘unconstrained’ version of the model provides:

- the DAM price, where no network constraints are considered,
- the generation by technology (and zone), that bids in the DAM,
- curtailment of renewables where renewable generation is in excess of system demand (without accounting for network constraints), and

[17] Developed with input from the ESO’s NOA team.

[18] Based on confidential data shared by the ESO for the purposes of this analysis.

[19] For the avoidance of doubt, the ‘unconstrained’ model version still considers charging and other zonal differences (e.g., in RES resource availability).

- behavioural response of demand customers at the DAM price combined with the user specific charge.

The locational investment decisions of different forms of capacity are also determined as a result of the unconstrained model. Considering optimal locational allocation as part of the unconstrained model implies that generation capacity connects based on envisaged revenues in the DAM.[20]

## Constrained model run

We use this optimal unconstrained capacity allocation as an input to a 'constrained' version of the model that incorporates our key transmission network constraints (i.e., the capacity limits between the seven transmission zones).

**What are the differences between the constrained and unconstrained model specifications?**

The constrained model specification can lead to more RES curtailment and typically higher CO2 emissions than the unconstrained model, because of the existence of network constraints and the potential need to curtail/dispatch-off certain RES/cheaper units and dispatch-on other, more expensive ones to respect these constraints.

The constrained model is used to model dispatch after taking into account capacity limits on the transmission network. We make the simplifying assumption that interconnector flows are determined in the DAM, and that their position is fixed at that level in the constrained run.

Similarly, we assume that some demand archetypes are not able to provide a response in the constrained run, while others can.[21]

In addition to the results of the unconstrained model, the constrained model can give us:

- the generation by technology (and zone) required to meet network constraints– this can be compared to the position in the DAM (as per the unconstrained model) to determine which generation technologies (and in which zone) had to be curtailed/dispatched-off or dispatched-on to meet network constraints (i.e., re-dispatch);
- the additional demand response incentivised to meet these network constraints where that customer types is able to do so; and
- the need for network investment at the different transmission boundaries, optimised against the costs of constraint actions. This is based on a rule which optimises constraint costs against the annuitised reinforcement unit costs at each boundary.

## Representing constraint management actions in the balancing market

Our constrained model specification includes a proxy of the balancing market (BM), but **considering constraint management actions only**, *and only for the limited number of key network constraints we capture*.[22] Noting these

[20] Investors do consider locational elements of tariffs, which therefore also influence the optimal locational allocation in our modelling.

[21] Specifically, among residential consumers, only households that have installed rooftop solar and/or batteries, and/or have acquired V2G technology for their electric vehicle are assumed to be able to provide a response in the constrained run. The rest of the households are assumed to remain unresponsive further to any load shifting included in the unconstrained model run.

Industrial and commercial consumers, particularly those that have invested in onsite generation and/or other demand-side response technologies, and commercial EV fleets with smart charging and/or V2G capability are all assumed to be able to provide a flexible response in the constrained market run.

[22] Our market model is deterministic and assumes perfect foresight. We capture a subset of the actions taken for locational balancing reasons, with regards to the key network constraints represented in the model only. We note that other considerations such as the need to maintain voltages on the transmission system, speed of response, reliability, potential duration, etc, are not included in analysis.

limitations, comparison of options can provide an indication of the extent to which constraint management actions and costs are likely to rise/fall in relation to the key transmission boundaries included in the model.

Our constrained model specification provides results on what constraint management actions need to be taken but does not explicitly give us BM imbalance prices or generator/demand side response revenues from providing constraint management actions. We are therefore not able to mirror the dynamics of the balancing mechanism in full. Instead, we estimate costs of constraint management actions in the model as follows:

- For generation technologies that are dispatched-on (i.e., where their generation under the constrained model is greater than what they bid in the DAM/unconstrained model), we value the additional 'BM' generation at that generator's short-run marginal cost.
- For any turn-down of generation (i.e., reduction in generation under the constrained model run relative to the unconstrained model run), the ESO receives the short-run marginal cost as a payment from those generators. For CfD-supported technologies that are dispatched-off/curtailed, we assume that the submitted bid takes into account the loss of the CfD strike price (which we proxy using the technology specific levelized cost of electricity (LCOE)).[23] As the generator would still be made whole in the DAM, we assume that their bid is at the CfD strike price net of the DAM price and any marginal cost savings. These bids will be negative in many cases as the LCOE for the given technology will be greater than the DAM price plus any marginal cost savings.
- For any decrease in net demand, we assume that the ESO would have to make the demand user whole for their DAM position by compensating them for the DAM price and tariff paid on that level of demand.[24]
- We assume that demand turn-up in the constrained run contributes to the avoidance of curtailment of CfD-supported technologies. As a proxy for the demand turn-up costs, we therefore assume that the ESO pays a similar price to the potential cost of curtailment of the marginal unit of renewable generation – i.e., the CfD strike price of the cheapest technology (again, proxied by the LCOE) net of the DAM price and any marginal cost savings for that technology.

### 2.3.2. Optimising dispatch and locational allocation of capacity

#### Dispatch

The model incorporates all generation technologies included in the FES scenarios. It solves for dispatch of these technologies based on their techno-economic characteristics (such as efficiencies, variable operational costs, fuel and carbon costs)[25] and other constraints, such as wind/solar availability profiles for intermittent renewable technologies.

For a subset of technologies, we model dispatch exogenously, in line with historical generation profiles, based on the assumption that these technologies remain within merit and follow a similar generation pattern each year. This applies to some dispatchable generation which we consider to be 'must-run' baseload technologies (nuclear and biomass/waste) as well as to run-of-river and reservoir hydroelectric generation.

[23] The LCOE aspect of this calculation is limited to CfD-supported generation (see Section 2.3.2 for details) and is intended as a proxy of the CfD strike price. We recognise that the applicable CfD strike price is not equal to every supported technology's LCOE given that the CfD auctions apply a uniform pricing rule, but we consider use of the LCOE to be a suitable proxy. This implicitly relies on the assumption that technologies with similar LCOEs are grouped together in pots (e.g., established vs. less established technology pots), which we consider to be a proportionate simplification for the purposes and scope of this project.

[24] In practice, some types of demand response may be compensated at a price that they bid into the balancing mechanism which is different to this assumption. Nevertheless, the approach taken here is considered proportional within the overall modelling framework.

[25] We take efficiencies from BEIS Electricity Generation Costs (2020): https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020.

Table 2.1 lists all generation technologies we include and our dispatch modelling approach for each.

*Table 2.1: Generation and battery technologies, dispatch modelling*

| Technology | Network (T or D) | Dispatch modelling |
|---|---|---|
| *Endogenous dispatchable technologies, including storage* | | |
| Gas CCGT, including gas CHP | Both | Endogenous |
| Gas OCGT | Both | Endogenous |
| Gas reciprocating engines | Both | Endogenous |
| Hydrogen | Both | Endogenous – using an inferred H2 price calculated in relation to the scenario gas price and methane reformation costs |
| Battery Storage (including lithium ion, compressed air and liquid air) | Both | Endogenous |
| Pumped storage | T | Endogenous |
| *Dispatchable 'baseload' technologies treated as exogenous in the modelling* | | |
| Nuclear | T | Exogenous, in line with current generation profiles |
| Biomass and waste (including biomass/ waste CHP, and biomass with CCS) | Both | Exogenous, in line with current generation profiles and FES load factors (largely baseload, particularly for BECCS) |
| *Endogenous intermittent renewable technologies* | | |
| Offshore Wind | T | Endogenous, based on location-specific availability profiles[26] |
| Onshore Wind | Both | Endogenous, based on location-specific availability profiles[27] |
| Solar | Both | Endogenous, based on location-specific availability profiles[28] |
| *Exogenous renewable technologies* | | |
| Hydro (including marine) | Both | Exogenous, based on 2019 generation profiles |
| *Behind-the-meter generation (allocated to demand consumer nodes – see section 2.3.3)* | | |
| Behind the meter batteries | D | Endogenous |
| Behind the meter solar | D | Endogenous, based on location-specific availability profiles |
| Gas onsite generation (CHP)[29] | D | Endogenous |

We model the majority of technologies as a single 'fleet', grouping all capacity (in each zone) together. For technologies such as gas CCGTs and OCGTs where the efficiency of existing and new fleets is likely to be significantly different, we model these separately and include separate estimates of efficiency and variable costs for each within each node of the model. This means that the new and existing fleets in each region can dispatch based on separate technical parameters.

For the rest of the technologies, differences in efficiency are typically less significant (e.g., pumped storage plants), or existing fleets do not yet exist (e.g., hydrogen plants), so plants are more likely to be at similar points in the merit order.

[26] Offshore wind profiles in each transmission zone are based on capacity-weighted average wind speeds (from renewables.ninja) at locations of existing and planned offshore wind farms are connected to each zone, based on data provided by Ofgem: https://www.renewables.ninja/

[27] Capacity factor profiles for onshore wind were provided by Ofgem. These were derived based on capacity-weighted average wind speeds (from renewables.ninja) at locations of wind farms operational or under construction (by Q4 2020) in each of our distribution and transmission network zones: https://www.renewables.ninja/

[28] Solar profiles are based on the solar irradiance at the zone centroid. Different technologies are assumed for distribution and transmission level. The transmission level profile assumes 2-axis tracking (tilt and azimuth). For distribution connected and household profiles, we assume no tracking. https://www.renewables.ninja/

[29] These are generators that sit at industrial sites. Informed by engagement with the FES team, we treat on-site generation as gas CCGT CHP generators and use expected efficiencies for this technology. They are modelled as part of industrial consumer demand nodes (for consumers that have taken up on-site generation). The total level of installed capacity of this technology generally declines over our modelling horizon in all scenarios, as industrial consumers adopt other behind-the-meter technologies, such as batteries.

## Locational allocation of capacity

We take total ‘system’ levels of installed capacity of each technology directly from the relevant FES scenario. This includes new capacity and closure of existing capacity.

However, the market model is also designed to optimise the regional allocation of several key types of generation technology across distribution zones and across the simplified representation of transmission zones. In doing so, it takes into account DUoS and TNUoS charging signals,[30] as well as differences in resource availability (where relevant).

We keep the total distribution- and transmission-level capacity of each technology from the relevant FES scenario and year fixed at projected FES levels.[31] I.e., the model does not optimise allocation of generation **between** the transmission and distribution zones.

As the model does not incorporate the full cost functions of generation technology (e.g., land costs, etc), it is only appropriate to include some optimisation of locational allocation where we envisage that DUoS charges would have a significant impact on the decision of where to locate relative to other cost factors which are not captured. We only include locational allocation of capacity in the model where we observe steady capacity growth which is ‘non-lumpy’[32] and where there is a reason to expect that charges may be a significant driver of locational investment decisions (e.g., nuclear capacity is not allocated endogenously given the lumpy nature of new capacity build up).

For those technologies where locational allocation is endogenous, we bound the total amount of capacity of different technology types within reasonable limits to prevent the model from allocating unrealistic levels of capacity to certain zones. These bounds also reflect certain constraints on movement of capacity such as planning and land use to some degree.

For both transmission and distribution connected capacity, the FES regional breakdown for the applicable scenario and year provides the ‘central estimate’ for capacity investment around which our bounds are defined. For the first spot year, we allocate capacity in line with the FES (i.e., fully exogenously). For later spot years, we allow the model to optimise investment within defined bounds either side of the projections in the FES.

Our approach to defining bounds is as follows:

- Upper bound:
  - We determine the maximum annual expansion rate which is included in the FES regional breakdown of capacity allocation for a given technology.
  - We assume that this maximum annual expansion reflects a sensible limit on the ability of a given technology to expand in any one year, implicitly taking into account considerations such as planning, connections and network capacity, etc.
  - We set this maximum annual expansion rate as the upper bound for the annual expansion that could be realised in any year.
  - For technologies with very low initial levels of capacity, this approach can lead to very high upper bounds, driven by growth from a very low level in a certain year. While allowing the given level of

[30] We do not include connection charges as an input into locational decision making *between* distribution zones but do include optimisation of connection costs as an input into the decision of location *within* a distribution zone.

[31] We make small adjustments to the proportions of distribution and transmission capacity for specific technologies, to exclude any distribution-connected generators with capacity of greater than 100 MW and a bilateral embedded generation agreement (BEGA) from the capacity labelled as transmission-connected in the FES. This adjustment is intended to help us better represent the different categories of generators from a tariff application perspective. See section 2.3.4 for more details and a discussion of implications.

[32] For technologies with declining capacity over our modelling horizon under our chosen FES scenarios, we model the location of capacity exogenously, to reflect confidential assumptions that the ESO makes about individual plant closures.

growth in the year in question, we consider any growth rates above 200% as unrealistic and apply the second highest observed growth rate as the maximum allowed in the model in all other years.

- Lower bound:
  - We apply a lower bound which is set at 50% of the additional capacity growth which is defined for the relevant technology in the FES.
  - The lower bound cannot fall below the 'existing' level of capacity defined in each region in the initial spot year.

The model then optimises locational allocation from the perspective of minimising system costs, considering locational charges (in line with the tariff options modelled, as set out in section 0), and natural resource availability.

We summarise our approach for modelling the locational allocation of generation capacity in Table 2.2 below.

Table 2.2: Generation and battery technologies, approach to locational allocation

| Technology | Network (T or D) | Locational allocation |
|---|---|---|
| Biomass and waste, including biomass CHP, waste CHP, and biomass with (BECCS) | Both | Exogenous at T level<br>Endogenous at D level |
| Gas CCGT, including gas CHP | Both | Exogenous, including existing fleet closures in line with the FES (regionally).[33] |
| Gas OCGT | Both | |
| Gas reciprocating engines | Both | |
| Gas onsite generation (CHP) | D | |
| Hydrogen | Both | Exogenous |
| Nuclear | T | Exogenous given lumpy investment (assuming that other non-modelled costs may dominate charges) |
| Pumped storage | T | Exogenous given lumpy capacity increases and assuming that other geographical factors and non-modelled costs are likely to be more important. |
| Hydro and marine | Both | Exogenous, assuming other geographical factors are likely to be more important. Very little capacity is added by 2040, with the exception of T-connected marine technology in selected zones. |
| Offshore Wind | T | Endogenous, considering zonal resource availability and charges |
| Onshore Wind | Both | Endogenous, considering zonal resource availability and charges |
| Solar | Both | Endogenous, considering zonal resource availability and charges |
| Battery Storage (including lithium ion, compressed air and liquid air) | Both | Endogenous, considering charges only |
| Behind the meter solar | D | Endogenous, considering zonal resource availability (for solar only) and charges.<br><br>Allocated separately to each consumer node including EHV-, HV- and LV-connected I&C consumers, as well as domestic consumers, with the split between I&C and domestic consumer capacity remaining in line with the FES. |
| Behind the meter batteries | D | |

[33] For these technologies, there are very few examples of increases in capacity over our modelling horizon, particularly for our central CT scenario.

## 2.3.3. Optimising demand side response and consumer technology uptake

The market model takes demand profiles for a range of behavioural archetypes and solves for demand in each period to be met at lowest system cost. Demand profiles are defined based on data for different types of users (exogenous). For each type of user, we also incorporate behavioural response functions that allow consumers to adjust demand in response to price signals, including both the charge and wholesale price signal.

### Types of behavioural response

The market model has been designed to capture the following responses of network users to charges and pricing signals:

- *The hourly generation mix that meets demand, taking into account price signals under charging reforms.*
- *How consumers might shift load away from periods of high prices and/or charges to other times of the day.*
- *How behavioural responses may change over time, including the impact of technology take-up.*

While the response of generators is determined based on the merit order stack that is a result of cost inputs into the model (as described in section 2.3.2), evidence relating to the behaviours of residential and small commercial consumers shows that they do not always respond rationally to price signals. For these consumers, we therefore need to develop assumptions regarding their response.

The remainder of this section summarises our approach for incorporating the behavioural assumptions of consumers, in particular how they adjust the time at which they consume electricity (load-shifting) and how responses may change over time (e.g., in relation to technology take-up).

#### Load shifting

We define load shifting as reduced demand at peak, but which is re-allocated to periods outside of peak such that the total volume of demand does not change.

As part of our literature review, we also explored peak shaving. Peak shaving represents reduction in demand at peak, but which is not re-allocated to periods outside of peak. That is, there is a net reduction in the volume of electricity demand. In practice, a proportion of demand reduction may reflect load shifting while the remainder reflects peak shaving.

However, the literature on load shifting is significantly richer than that on peak shaving and this reflects our prior expectation that most activities of residential and small commercial customers that are affected by price signals would still be undertaken but may be shifted such that load shifting is more prevalent than peak shaving. Our modelling incorporates assumptions of load shifting but does not include peak shaving where load is not shifted to another part of the day.

*Figure 2.3: Load shifting: Demand outside of peak increases*

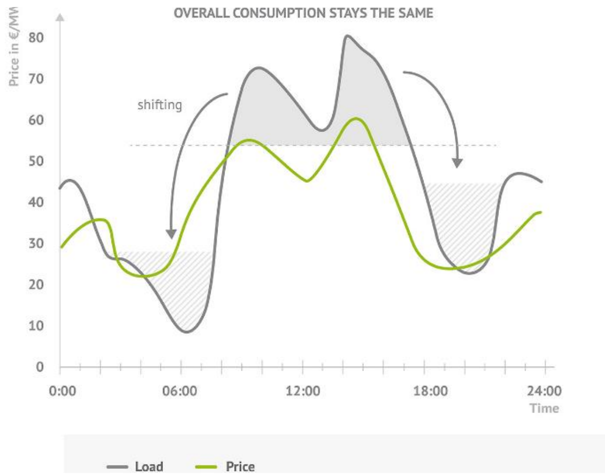
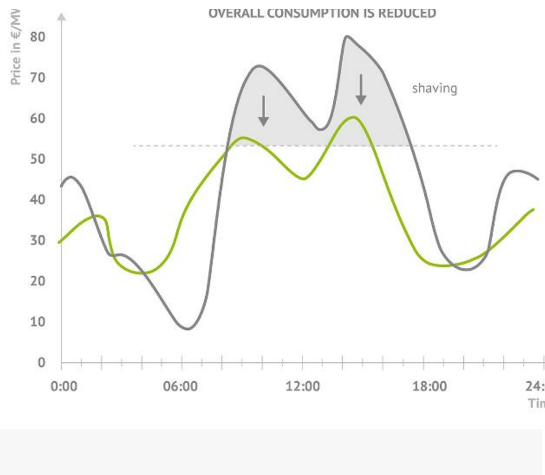



*Figure 2.4: Peak shaving: Demand outside of peak stays the same*



## Behavioural responses assumptions

Our approach for modelling of behavioural response combines three key inputs:

- **Take up of different types of technology**: Set by the relevant FES scenario. E.g., CT has higher take-up of smart-charging EVs than the SP scenario.
- **Pass-through of ToU signals – also set by the FES scenario**: This represents the extent to which time of use signals are passed through to consumers by suppliers and is taken from the relevant FES scenario. We only apply the pass-through rates from the FES to non-optimising technology. We assume that consumers with optimising technology choose to take up a ToU tariff (pass through = 100%) to ensure they can appropriately benefit from their technology choice.
- **Elasticity of response of consumers with different types of technologies**: We establish how much load different types of consumers may shift based on the strength of price signal. This draws on our behavioural literature review to establish elasticities.

To develop our behavioural response assumptions, we follow five steps.

### Step 1: Literature review

We carried out an extensive review of the literature on behavioural responses of consumers to different types of charge (this covered over 90 studies ranging in context, geography and age). We summarise the findings from our literature review in Appendix A.

### Step 2: Define behavioural archetypes

Our modelling has been designed to allow for the impacts of the options to be considered for a broad range of user archetypes, subject to having data on consumption, capacity, income, etc. However, for modelling of the behavioural responses discussed in this working note, we need to consolidate these user archetypes into a sub-set of '*behavioural archetypes'.* These behavioural archetypes are defined primarily to understand the effects of demand reduction on the system and on the costs and benefits of each option.[34]

Based on our literature review, we have consolidated behavioural archetypes based on the following:

1. Is the size of the archetype sufficient to have material impacts on demand at peak?
2. Do different types of consumers have materially different demand profiles?
3. Is the magnitude of the behavioural response likely to be materially different from another behavioural archetype?
4. Is there an evidence base to develop a sufficiently robust set of assumptions?

### Step 3: Assign behavioural archetypes as 'optimisers' or 'non-optimisers'

Based on our review of the literature we have considered:

1. Whether each behavioural archetype is likely to approach optimisation of their response to price and tariff signals or provide a more limited response; and
2. The extent of response for those consumer archetypes who are unlikely to optimise their demand profile to reflect price or tariff changes.

We have applied this to separate the behavioural archetypes into two:

[34] Analysis of distributional bill impacts carried out on a wider set of consumer archetypes than is defined in the market model.

- **'Non-optimisers'**: Those that do not fully optimise their consumption based on price and tariff signals (including consumers with no enabling technologies) but may provide a more limited behavioural response based on the literature.
- **'Optimisers'**: Those technologies that we expect to enable the user to optimise their consumption based on price and tariff signals as far as that technology's capacity will allow (e.g., EVs with smart chargers, batteries, heat pumps with thermal storage).

We set out our assumptions on load shifting of different behavioural archetypes in the table below.

*Table 2.3: Load shifting assumptions*

| Consumer archetype | 'Optimisers'/ 'Non-optimisers' | Strength of evidence base |
|---|---|---|
| Domestic | Non-optimiser | High |
| Domestic with solar PV (no storage) | Non-optimiser | Low |
| Domestic EVs (with smart charging) | Optimiser | Medium |
| Domestic EVs with V2G | Optimiser | Medium |
| Fleet EV (with smart charging) | Optimiser | Medium |
| Fleet EV (with V2G) | Optimiser | Medium |
| Domestic – Heat Pumps (no heat storage) | Non-optimiser | Low |
| Domestic – Heat Pumps (with storage) | Optimiser | Low |
| Domestic with battery storage | Optimiser | Low |
| Commercial (low consumption) | Non-optimiser | Medium |
| Industrial and commercial (medium and high consumption) | Non-optimiser | Low |
| Industrial and commercial (on-site generation) | Optimiser | Low |

**Step 4: Estimate magnitude of behavioural response and introduce as elasticities in the market model**

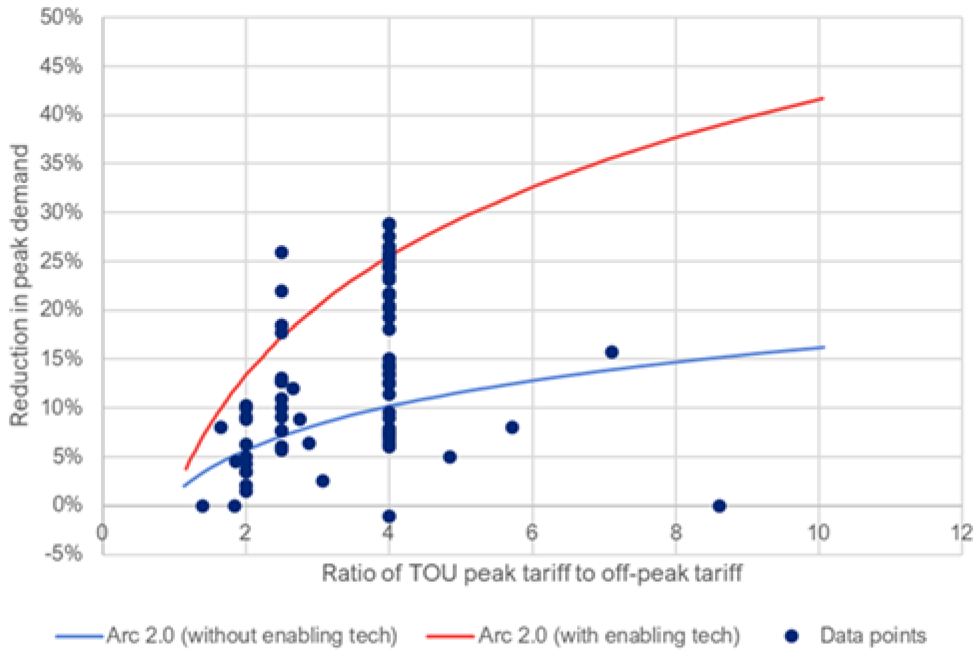
For 'optimisers', we assume that they respond optimally to signals for charging and discharging based on the wholesale price and the charge applied to them.

For 'non-optimising' technologies, we develop assumptions for the strength of response based on our review of the behavioural literature. We model the response of 'non-optimising' technologies using two dummy storage units. These storage units are designed to charge (representing a shift of load away from the period) at a high and low defined price point and to discharge (i.e., shift load to a different period) across the remainder of the day. The high and low-price points reflect the fact that non-optimisers may shift a smaller or greater proportion of their load depending on the magnitude of the delta in the price signals across the day.

Our evidence base on behavioural response is greatest for aggregated domestic consumers. We have defined a behavioural response elasticity curve which sets the level of demand reduction at peak based on the price differential between peak and off-peak periods. We assume that a consumer with the same type of technology maintains their level of behavioural response over time. I.e., individuals only become more or less responsive because of their technology choices rather than any inherent change in preferences.

In order to define the behavioural response curve, we have used the ‘Arcturus Curve’.[35] This curve is extrapolated from a comprehensive meta-analysis encompassing a large number of trials from the literature. Using this set of data allows for us to draw on a single consistent set of data in defining consumer elasticities.

*Figure 2.5: The Arcturus Curve*




The Arcturus curve is expressed as a ratio of the ToU peak tariff to off-peak tariff. For our modelling, we need to establish elasticities as price deltas.

To convert from a price ratio base to a price delta base n, we have used estimates of the GB day-ahead price, drawing on a ‘dummy’ run of the market model for each modelled scenario.[36] We then calculate the price ratios from the GB price estimation, and apply the Arcturus curve directly to that to get the behavioural response as a function of price deltas.

To incorporate the elasticities into the market model, we approximate the curve with two price points, accompanied by corresponding load which consumers shift at that price delta.

### Step 5: How behavioural response changes over time

We incorporate assumptions of how behavioural responses change over time in three ways:

1. For ‘non-optimisers’ we build in a level of shift from the Arcturus Curve (Figure 2.5) indicated by the red line (without enabling technology) to the blue line (with enabling technology). We assume a simple linear trend in the shift from one to the other. This allows us to reflect an inherent growth in load shifting capabilities, even for those consumers who do not take-up one of the technology choices we have set out.
2. Our model incorporates changing take-up of consumer technologies (e.g., EVs with smart charging, batteries, etc). As an increasing proportion of consumers become ‘optimisers’ load shifting levels grow.
3. We take assumptions about take up of time of use tariffs from the relevant FES scenario. This leads to an increase in the extent to which consumers face pass-thorough of the DAM price and charges over time.

[35] Faruqui (2017) Arcturus 2.0: A meta-analysis of time-varying rates for electricity

[36] The dummy runs for each modelled scenario are three initial runs, using the 2023/24 counterfactual tariffs (which are assumed to remain flat for all three years). These market model simulations are then used for extrapolating the tariffs more appropriately over our modelling horizon (as outlined in section 2.2.1) as well as calibrating the behavioural response elasticities in relation to the typical peak vs. off-peak DAM prices from the unconstrained run.

### Optimising consumer technology take-up

For these consumer generation technologies where the location of take-up is defined as endogenous (see Table 2.2), the market model endogenously determines the regional location allocation (subject to bounds), based on charging signals (as well as RES resource availability for rooftop solar). This reflects the different take-up incentives that may exist in different zones and how charging policy may impact on these incentives.

Section 2.3.2 describes our approach to modelling endogenous locational allocation for generation technologies (including behind the meter consumer generation assets) and setting appropriate regional bounds, in line with the FES.

The same approach is also employed for modelling the variation in regional take up for other consumer technologies, i.e., EV smart charging and V2G technologies. For these technologies, the bounds are set in relation to the regional variation in the uptake of EVs assumed in the FES, with the split between domestic and fleet EVs remaining in line with the number of domestic vs. commercial/industrial electric vehicles.

## 2.3.4. Modelling limitations

Our modelling framework has been designed to capture a very broad range of potential impacts, including impacts on DAM outcomes, policy support costs, constraints, and transmission and distribution network investment. To achieve this breadth of analysis, several assumptions and simplifications have been introduced into the model which may impact on the outcomes observed. These modelling choices may also limit the extent to which the framework is able to capture some of the potential benefits and disbenefits of Ofgem’s proposed reforms. In several cases, we have supplemented the modelling to support modelled outcomes with additional supplementary analysis. For example, while we do not model re-optimisation of capacity between technologies, our investment analysis demonstrates the impacts of reform on revenues of different technology types. We summarise some of the key limitations of the modelling framework in Table 2.4.

*Table 2.4: Limitations of the model*

| Assumption | Modelled approach | Possible implications on modelled outcomes | Supplementary analysis (where applicable) |
|---|---|---|---|
| **Exogenous level of total capacity of each technology** | In the model, we take the total level of capacity of each producer and consumer technology from the FES scenarios.<br><br>Note that our model does allow new capacity to choose where on the system to locate within defined bounds (see below). | Our model does not allow 're-optimisation' of the choice of technology in response to revenue outcomes. In practice, investors may respond to revenue signals by shifting investment from one technology to another. Therefore, our modelling may over-estimate the impacts of reforms on RES support costs that must meet revenue requirements for a fixed set of capacity.<br><br>This simplification also has implications for our assessment of carbon impacts of the proposed reforms. As we incorporate the same level of capacity of each technology within the analysis, we do not reflect any reduction in capacity. Instead, we assume that policy support will increase to meet any additional revenue shortfall. The carbon emissions impacts that we present in this report are therefore limited to 'operational' impacts, i.e., resulting from dispatch and re-dispatch of a given capacity mix. | Based on our modelling results, we have developed analysis of the revenue impacts for each type of technology in each location on the system. This allows for insight to be drawn regarding the likely impacts on investment into different technologies and for a discussion of implications for the modelled outcomes. |
| **Bounding of the locational allocation of capacity** | Our model allows renewable capacity to choose where to locate on the system in response to expected revenues. However, the ability of users to choose where to locate is bounded relative to the locational allocation of capacity in the FES[37].<br><br>The bounds that we apply widen over the appraisal period relative to the FES. This | Our modelling of the locational allocation of capacity does not reflect the complexity of locational choices which exist in reality.<br><br>Where our bounds are narrower than would be the case in reality, this may constrain investor decision making, limiting the strength of locational investment signals sent under the counterfactual and the policy option and vice versa. As Ofgem expect their proposed TNUoS reforms to provide more | By bounding the deployment of capacity relative the FES, we include the potential for investment in new capacity to respond to any changes in price signals observed under the reforms.<br><br>We supplement our modelling with revenue analysis (described above) |

[37] For a description of how our locational capacity bounds work, please see our accompanying Methodology Note.

| Assumption | Modelled approach | Possible implications on modelled outcomes | Supplementary analysis (where applicable) |
|---|---|---|---|
| | reflects the increasing uncertainty of factors which may impact on the choice of investors regarding where to locate new renewable capacity.<br><br>In the modelling itself, we do not allow for capacity to re-allocate between the transmission network and the distribution network. | consistent locational signals for embedded generation, this may have consequences for the modelled benefits of reform.<br><br>We do not directly model the potential for investors to respond to the change in signals by deciding to locate capacity on the transmission rather than distribution network (or vice versa). | which can provide further insight on how different types of technology may respond to signals. This includes geographic decisions of where to connect on the network as well as decisions regarding the voltage level at which to connect. |
| **Simplified representation of transmission network** | We incorporate a set of transmission boundaries into our market model. However, our model is not designed to be a detailed representation of the transmission network in full. Instead, we engaged with the ESO to identify and model six key projected transmission boundaries on the system. Transmission boundaries tend to evolve over time, driven by the evolving generation background. This evolution is not modelled. | Our constrained model run does not reflect the complex and evolving set of transmission boundaries that are observed on the transmission network in practice. No intra-zone constraints (i.e., within each transmission zone) are modelled. By modelling a set of key boundaries, we capture the potential of reforms to impact on the need for network investment to some extent, but we are likely to under-estimate this need given the simplification of the network.<br><br>This limitation will apply equally to the counterfactual and to the policy option, such that the overall effect is limited to the differential in transmission capacity requirements between the two. | No supplementary analysis undertaken. |
| **No feedback loop between transmission network development and charges** | Our model does not include a feedback loop between network investment, user behaviour and network charges.<br><br>TNUoS tariffs are modelled by the ESO under the 2019 FES Two Degrees scenario. TNUoS tariff modelling reflects the change in policy regarding charging of embedded generators | In practice, additional network capacity is funded through network charges, and network charging models take into account developments regarding investment and dispatch decisions when forecasting TNUoS charges which are designed to recover revenue.<br><br>As our modelling makes use of a different set of scenarios in comparison to the ESO's TNUoS modelling, we can observe a | We capture the differences in total revenue recovery between the two sets of models and treat this as a consumer welfare impact. This assumes that the revenue over or under-recovery would be passed through to consumers. |

| Assumption | Modelled approach | Possible implications on modelled outcomes | Supplementary analysis (where applicable) |
|---|---|---|---|
| | and consequential impacts on other users. However, the modelling of TNUoS charges does not take into account the outcomes that we model regarding investment and dispatch decisions.<br><br>As the policy options do not affect distribution use of system (DUoS) charges, these charges are the same under the option and the counterfactual. | disconnect between the level of revenue which is recovered in each set of models (i.e., this may lead to over- or under-recovery of revenue requirements over the period of analysis). In practice, an under-recovery of revenue would be reflected in higher charges for consumers and/or producers relative to the modelled outcomes. An over-recovery would lead to a reduction in charges relative to modelled outcomes.<br><br>In practice, this under- or over-recovery would result in impacts on end consumers, either directly through tariff increases/decreases or indirectly, as producers pass on changes to tariffs, e.g., through the DAM price or through a change to the level of subsidy they require through support schemes. | |
| **Simplified representation of distribution network charging application** | We include three 'levels' of connection in our modelling:<br><br>1. Direct transmission-connected,<br><br>Direct distribution-connected (regardless of capacity), and<br><br>Behind-the-meter ('BtM') generation (which we assume is located on-site or in a consumer's home). | This approach does not capture certain nuances within the existing definition of charges.<br><br>Currently, distribution-connected generation that has capacity of greater than 100 MW and a bilateral embedded generation agreement (BEGA) pay Generator TNUoS. However, our model assumes that these generators pay/receive the same as embedded generators, however. We are therefore over-estimating the impact of reform slightly as, in our model, the current EET arrangements for embedded generators are applied to a sub-set of customers who would actually pay Generator TNUoS under the counterfactual.<br><br>Based on FES data, embedded generation with capacity over 100 MW and with a BEGA represented less than 8% of total generation capacity in 2019. Given the relatively small size of | No supplementary analysis undertaken. |

| Assumption | Modelled approach | Possible implications on modelled outcomes | Supplementary analysis (where applicable) |
|---|---|---|---|
| | | this specific customer group, we consider the impacts on outcomes are likely to be limited.<br><br>Our model also misses a small amount of nuancing of the proposed TNUoS reforms with regards to the application to embedded generation with capacity of less than 1 MW that is not BtM. We treat this as direct-connected generation, meaning that it pays Generator TNUoS rather than the EET charge under the reform option.<br><br>The majority of generation of less than 1MW is BtM in the FES scenarios and therefore the impact of this assumption is limited. In 2019, more than 99.9% of total microgeneration (with less than 1MW capacity) was BtM. | |

## 2.4. Distribution network model

### 2.4.1. Summary of approach

As part of the impact assessment for the SCR, we model the impact that different access and charging options have on the cost of managing and investing in the distribution networks against different projected energy scenarios. Our expectation is that different charging structures could reduce the impact that growth in demand and/or generation has on the networks, for example:

- by encouraging new generation to access the network in locations where there is more spare capacity; and
- by prompting customers to reduce their electricity demand at the times of system peak and/or embedded generation to reduce dispatch at times of greatest export capacity constraints.

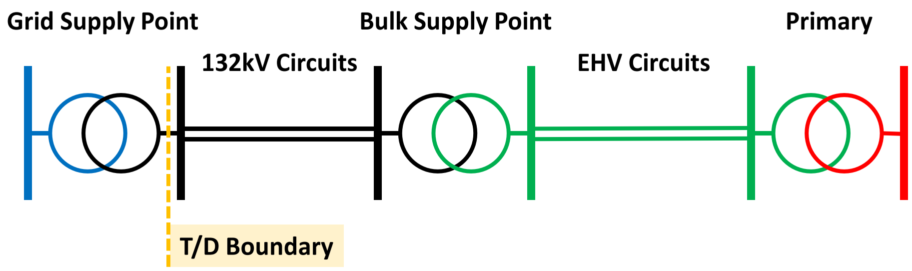
We have integrated existing TNEI models and methodologies to develop a representative network model for quantifying impacts, using the underlying data within the cost models developed by the ENA. We model all voltage levels of the distribution network.

### 2.4.2. Network representation

We use a simplified representation of each network that has been prepared by the cost model subgroup.

This required defining the entire GB distribution network down to the primary level as if it uses a radial topology. Our EHV modelling uses data received from DNOs (within the populated cost models). The radial topology is illustrated in Figure 2.6 below.

*Figure 2.6: Illustration of radial network*




The locational granularity of charges has been considered as an essential element for consideration of the charging options. Modelling approaches that provide a narrower representation of the network would not allow for these effects to be measured properly. To ensure breadth of analysis of the network, trade-offs against depth/detail of representation have been necessary. We have therefore modelled a broader extent of the GB distribution network but made certain simplifications regarding the depth and complexity of those networks (e.g., we did not use full load flow analysis).

### 2.4.3. Modelling period and approach

We separate the 20-year modelling period into four blocks, each of five years. These blocks coincide with anticipated five-year RIIO periods (e.g., 2023-2027, 2028-2032 etc).

For each of the five years within a period, we calculate extrapolated charges, based on the current capacity of the network and modelled utilisations.[38] We then run a cost minimisation model to identify the locations in the network at which new demand and generation capacity connect. The starting point for this is the capacity that the DNO has added to the network in the previous five-year block (as represented within the extrapolated DUoS signals). By signalling these reinforcement costs, the Distribution Reinforcement Model also allows for a representation of how

[38] The Distribution Reinforcement Model extrapolates DUoS charges endogenously by determining how the unit cost changes over time (based on asset value, rating, and spare capacity), and then applying this to outputs from the DUoS charging model, which give, for each tariff, timeband and charge element, the amount contributed to the tariff per £1/kVA/year of unit cost.

signalling reinforcement costs through connection charges changes users' choices about where to locate their capacity.

After repeating the estimation of locational decisions for each of these five years, an algorithm is used to identify necessary reinforcement costs, factoring in the additional generation and demand capacity added in the previous step, and incorporating the behaviour responses to charging signals. This informs the level of distribution network reinforcement needed, allowing DNOs to use non-firm connection options and procurement of flexibility services where they can help to avoid network reinforcement.

### 2.4.4. Generation and demand capacity

Before starting the modelling runs for each year, the first step in the model is to calculate the amount of generation and demand capacity at each location associated with smaller users, adoption of low carbon technologies, and existing large generation and demand.

#### Demand

The model takes current measured demand at every primary on the network (from the cost model) and apportions this across all voltage levels below the primary. It also splits demand between domestic, non-domestic demand and larger non-domestic demand (i.e., that with a defined level of import capacity). Demand is multiplied by a relative growth factor to establish demand at each primary over the modelling period. This growth factor is determined by the FES scenario and calculated as an output from the market model.

#### Low carbon technologies

Weightings are used to assign more low carbon technologies to some types of location and less to others, based on an indicator of rurality. This represents some of the clustering in low carbon technologies that is expected – e.g., higher rates of vehicle ownership in suburban areas compared to dense urban or sparse rural areas as well as higher rates of rooftop solar PV in rural areas.

We have used the UKPN DFES to develop these rurality weights. Their DFES gives scenario projections by LSOA across all three of their licence areas. We have used the RUC2011 study to find the rural category for each LSOA. From this we have identified relative weights for different types of technology and rurality, in terms of amount of LCT per domestic customer.

#### Existing large non-domestic demand and generation

Initial levels of large non-domestic demand are determined directly as an input for the current year, denoting the location and the technology type. For non-domestic demand, this is based on the tariff model inputs that have been provided by the DNOs for EHV tariff modelling. For generation, we have mapped the cost models to the generation capacity information in each DNOs Long Term Development Statements, as this also provides details on generation types.

### 2.4.5. Determining costs of a solution

A set of possible solutions to additional capacity requirements is included in the model along with costs of each asset solution for each voltage level. As in the cost models, this distinguishes between different types of assets (including overhead pole lines, overhead power lines, cables, ground mounted subs and pole mounted subs). This allows the capital costs of a solution to be calculated and minimised. We assume the assets that are installed are never removed.

The solutions we have included and the voltage levels to which they apply are summarised in Table 2.5.

*Table 2.5: Voltage level mapping*

| | LV | HV/ LV | HV | EHV/ HV | 132kV/HV | EHV | 132kV/ EHV | 132kV |
|---|---|---|---|---|---|---|---|---|
| New parallel circuit | | | | | | | | |
| Circuit overlay | | | | | | | | |
| Split circuit | | | | | | | | |
| Phase rebalance | | | | | | | | |
| New substation | | | | | | | | |
| Upgraded substation | | | | | | | | |
| Extra Transformer | | | | | | | | |
| Contracted Flexibility | | | | | | | | |

Costs for reinforcement per km are included within the cost model that the DNOs have developed. We have used this as the basis of the cost assumptions on our model, enhancing this with other information about solution costs and incremental capacity from the ENA's recent analysis of LCT impacts.

### 2.4.6. Determining profiles and asset ratings

To determine profiles' network impacts we need to understand how to represent the profile used for network planning under peak demand and reverse power flow conditions. These profiles are taken based on outputs of generation and demand profiles, incorporating the behavioural response included in the market model where relevant. For each type of technology, we take a single value of the profile in each of the timebands that are represented in the cost and tariff model.

Both the peak and reverse power flow profiles also incorporate limitations that reflect the assumptions made within the P2 planning standards. For example, rather than take a wind farm's maximum possible dispatch during the winter peak demand period, a DNO would use F-Factors as defined in P2 with the effect of reducing expected output to account for variability.

### 2.4.7. Flexibility options

A simple option for flexibility is included in the model in both the options and the counterfactual. This provides DNOs with an alternative to network reinforcement. Given limited data on flexibility prices, our modelling only includes a simplified representation of flexibility services which are available to all DNOs at a given price per unit of flexibility procured.

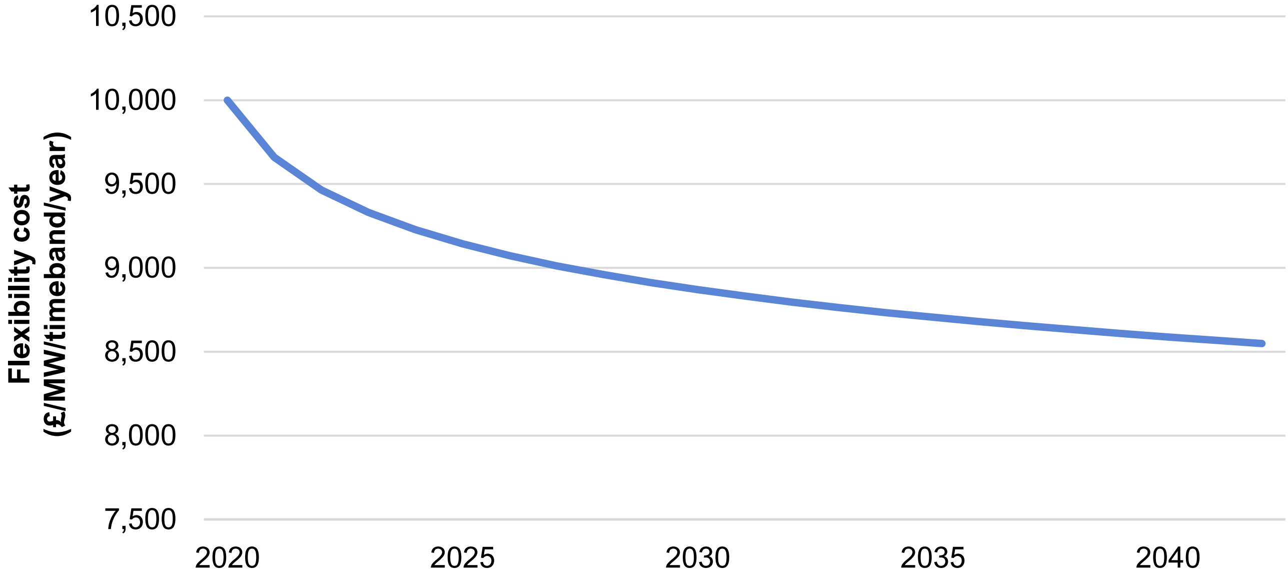
DNOs choose to use these alternative flexibility services where the optimisation allows for flexibility to be used at a discount on reinforcement, therefore allowing for deferral of capital expenditure.

We have assumed an initial £/MW/timeband/year price for flexibility of £10,000 per MW per year in each timeband, and we assume that the price of flexibility decreases exponentially at a rate of 5% per year. These costs have been referenced against data on existing contracted flexibility available from Piclo[39].

[39] Piclo (2020): https://picloflex.com/

We have also included limits on the extent to which flexibility can be relied on, for both individual assets as well as at a licence-wide level.

*Figure 2.7: flexibility cost timeseries*




Given the uncertainty in these costs and the future development of flexibility markets, all of these assumptions are tested through a sensitivity which sets the price of flexibility to £20,000 per MW per year in each timeband.

### 2.4.8. Location decisions of network users

In addition to optimising the costs of the distribution network, the Distribution Network Reinforcement Model is also used to approximate the locational decisions of network users within a distribution zone with respect to the signals that are provided from DUoS and connection charges.

It does this by modelling the additional amount of demand and generation of each type that is deployed in each distribution zone and optimising this to minimise the cost of deployment of this capacity. It optimises this function from the perspective of the user. I.e., it minimises the costs of deploying generation/demand capacity after incorporating the DUoS charges under each options package and including a representation of connection charges.

This modelling is done for a single year, with no foresight included in the model of how charges change in the future. This is primarily because of the complexity with which charges change under the options in response to users' decisions, with these changes being both non-linear, and cumulative (e.g., affected by the decisions of multiple users).

In addition, taking the level of deployment of capacity as exogenous is, while necessary for aligning with our broader modelling approach, nevertheless somewhat unrealistic. In reality, if charges are too high then it may just lead to a specific generation project not going ahead. In our modelling framework, that generation is instead relocated to a more cost-effective part of the network. This means that some of the important aspects of the connection charging regime, such as the management of the queue of prospective users, cannot be accounted for.

To account for some of these limitations, we impose bounds on the ways in which new capacity can be deployed:

- We limit the extent to which new capacity of each type can be deployed at a single location, for example based on the typical ratings of new circuits for different voltage levels (e.g., ~35MVA for a new 33kV connection).
- We prevent certain types of technologies from being deployed on specific voltage levels. In particular, we only allow large generation to connect to the HV circuit level and up.

- We restrict certain types of generation from being deployed in networks based on how urban or rural they are. At a high-level, wind farms can only be deployed in the most rural areas, with fewer restrictions for solar PV, and fewer again for other generation types and storage.
- We restrict the extent to which the proportion of each technology deployed on each voltage level can change compared to the current proportions by voltage level. These restrictions are strongest for demand, and least restrictive for storage and dispatchable generation.
- We also restrict the extent to which any type of technology can be too heavily concentrated in a small number of BSP or GSP groups, again, with restrictions that are stronger for demand than generation.
- Lastly, we also include disincentives for new connections that substantially increase the need for capacity at any particular location (e.g., new connections can lead to a need to double the capacity of the network), even for options where there is not a connection charge for reinforcement. This is intended to provide a simple approximation of some of the practicalities associated with getting connections. E.g., if users trigger too much reinforcement, then their timescales for connection may be delayed, or the “high-cost rule” for connection charges might be applied. This assumption only applies in areas which are already very constrained, or which would otherwise attract a very large amount of new demand/generation capacity (e.g., very low charges/high credits under an option with no connection charge).

### Connection costs

To incorporate the costs of new connections, we introduce another term into the model which represents the cost associated with breaching existing network capacity and triggering connection-based reinforcement.[40]

The costs associated with new connections are incorporated into location connection decisions within each distribution zone. This leads to more connections being assigned to those locations with lower network reinforcement requirements, therefore reflecting locational signals from the connection charge where relevant. In the presence of a shallow connection boundary, the costs of reinforcement would not be incorporated into user connection decisions.

Th connection costs are designed to reflect various aspects of the policy design such as changing the cost apportionment factor to 50%, and different designs of the voltage rule.

## 2.4.9. Allocating load shifting across the network

The market model calculates the average load shifting for each distribution licence area as a whole, in line with behavioural assumptions described in section 2.3.3. However, at this level of granularity, the model does not capture the possible benefit of having more granularity of charges within a given DNO area, which Ofgem considers may encourage higher levels of load shifting in those areas that are most constrained.

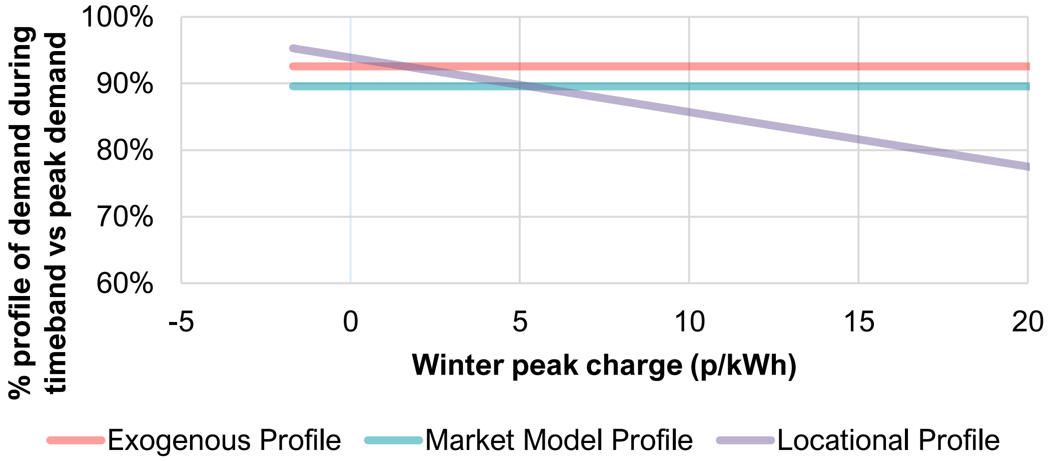
The extent to which load shifting would be allocated across an individual distribution zone given differentiation in charges is relatively uncertain. However, we assume that load shifting can be influenced by the level of charges at locations within the distribution network. I.e., locations with higher charges see higher load shifting than the average for the zone, and locations with lower charges see lower load shifting than average. However, we constrain this such that the average profile across all locations matches that from the market model (e.g., the average change in profile in a given distribution zone is 0%).

This is illustrated in the figure below, which shows how the profile for one technology (electric vehicles) varies against the total charge, during the winter peak timeband.

[40] For the avoidance of doubt, we model the impact that connection charges have on user decisions of where to locate on the distribution network, but do not capture how these costs are allocated to specific new connectees through the connection charge.

In this example, the Exogenous Profile is the input into the market model before load shifting. The market model Profile is the estimate of demand defined by the market model which incorporates load shifting. Both are flat across all locations within a single distribution zone, at 93% and 90% respectively. However, when we incorporate our assumptions about locational load shifting, the demand profile is below 80% for the location with the highest charges in the zone. In those locations where a credit is present, the demand profile is above the Exogenous defined estimate.

*Figure 2.8: Electric vehicle locational profile during winter peak timeband*




The extent of locational variation for each technology is based on the outputs of the market model, considering the relationship between load shifting and charges within different distribution zones. We assume that renewable generation does not exhibit any locational load shifting.

### 2.4.10. Reinforcing the distribution network

The Distribution Network Reinforcement Model assumes that the power flowing through an asset (after accounting for flexibility services) must be less than its rating. An optimisation function is then used to minimise the cost of deploying flexibility throughout the network, and reinforcing assets, subject to this constraint. This takes into account the locational decision of network users regarding where to connect to the distribution network and locational load shifting, as described above.

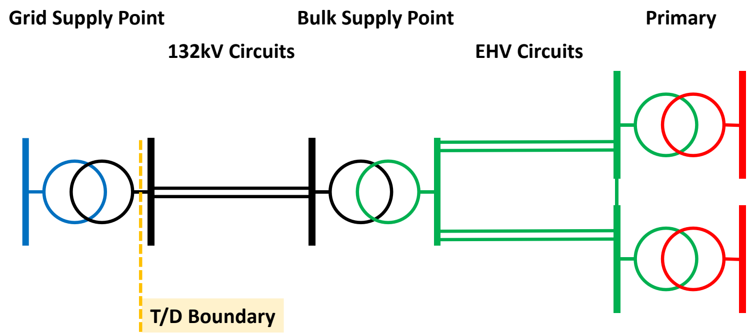
### 2.4.11. Modelling limitations

The modelling task for this analysis required consideration of a broad range of impacts across all distribution zones and all voltage levels. This required a focus on breadth of network modelling rather than very detailed modelling of particular features/elements of a distribution network zone. However, it also leads to several limitations which should be noted in interpretation of modelling and outputs. In all cases, consistent assumptions are applied to the counterfactual and the policy options which limits the impact of assumptions to the effect of the policy options on drivers that are not captured.

Firstly, under our approach, we are only able to account for issues associated with thermal utilisation of the networks. There are other technical factors that can (and do) drive investment in the networks such as voltage fluctuations, fault levels, network stability etc. These additional factors are more technically complex, and long-term behaviour may be more uncertain, which means that they are less suitable for inclusion in the modelling. However, given this, it may be necessary to acknowledge that these other factors may have some impact and hence, that this implies that assessments of investment requirements may be an underestimate. This is expected to be the case for voltage rise driven by generation on lower voltage levels, which has been recognised as a problem in generation dominated areas.

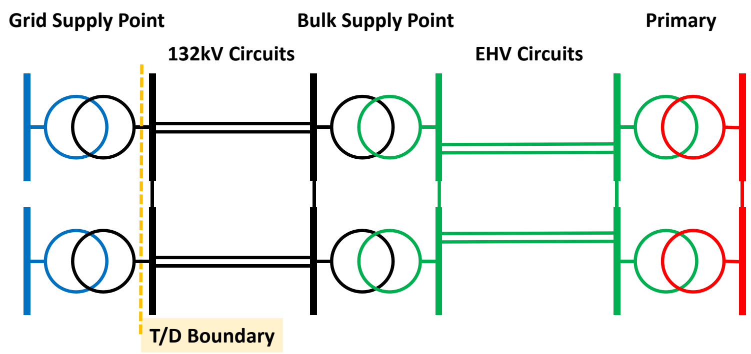
Secondly, there are parts of the distribution network that are not well represented by this simple radial topology. For example, it is relatively common for some networks (particularly EHV networks in rural areas) to use non-radial ring topologies, where there is greater interconnection of circuits to provide security in the event of a fault. The manner in which power flows in these networks is more complex than in the radial network and depends on the design and length of the circuits in question. A simple ring network is illustrated in the figure below.

*Figure 2.9 Illustration of ring network*




In addition, there are some parts of the network which are much more heavily “meshed”. A simplified example is shown below.

*Figure 2.10 Illustration of meshed network*




The majority of Scottish Power’s MANWEB network in North Wales is meshed. This was considered when implementing these networks in the cost model, achieved by defining the cost model inputs in terms of “groups” of substations and circuits, rather than individual substations and circuits. We have applied a consistent approach to the cost model for the IA modelling but, given these differences, as well as some different approaches taken by the DNOs to prepare their cost model inputs, we are cautious when making comparisons of costs and impacts across individual DNOs. Rather, we recommend a focus on overall modelled outcomes on distribution network costs across the system as whole.

## HV and LV network assumptions

Particular assumptions have been applied for modelling of HV and LV networks which should be noted.

In alignment with the development of the unit costs models, we assume that all of the HV, HV/LV and LV assets below a specific primary are homogenous in terms of their demand, assets ratings, costs etc. This assumption means that we do not capture variability in assets below a primary.

Additionally, our representation of the utilisation of the assets at these lower voltage levels is based on extrapolating from the primary level down, including assumptions about diversity. This means that, particularly for the LV voltage level, estimates of utilisation may be less reliable than those modelled for the EHV and 132kV networks.

In early years of modelling, load shifting might materialise at the system level before DNOs develop sufficient confidence in measurable and consistent behavioural responses to charging signals at lower network levels to enable incorporation of responses into HV and LV network planning. We note that the extent of load shifting in our modelling grows over time from relatively low levels in the initial years of analysis. Nevertheless, adjustments for load shifting in relation to costs of HV and LV reinforcement in early years may lead to a small under-estimate of reinforcement costs at these voltage levels.

Given additional assumptions required within the analysis, we consider impacts at HV and LV levels to be subject to a wider range of uncertainty relative to those observed at EHV level. In our reporting, we present the impacts on the EHV and 132kV network levels separately to those on the HV and LV voltage levels.

## 2.5. Impact assessment model

We combine market model and Distribution Reinforcement Cost Model outputs in an Impact Assessment Model, which calculates the NPV[41] for a number of key impacts under each charging option and compares this against the counterfactual.

At a high level, market model outputs allow us to quantify the following key impacts:

- **Bill impacts**, based on the impact of the DAM price, the tariff, and the demand responsiveness of different consumers.
    - This allows us to also produce distributional impacts of bill impacts for key consumer archetypes.
- **Producer surplus**, based on the impact of the DAM price on market revenues net of operational costs and net of tariff costs, by generation technology and by zone. This also includes the impact of locational decisions over our modelling horizon on tariff costs.
    - This allows us to analyse how impacts on producer surplus may affect investment and closure decisions.
- **'Missing money'** by generation technology and zone, allowing us to estimate impacts on the revenue that needs to be recovered through the RES support scheme (CfDs) and impacts on 'missing money' of capacity that is not supported through RES schemes.
- **Impacts on CO2e emissions**.
- Impacts on constraint management actions, and **constraint management costs**.
- **Transmission network capacity reinforcement and cost**, by boundary.
- Based on the simulated market model demand and generation levels of different users, we also calculate total TNUoS and DUoS tariff revenues and the resulting **impact on tariff residuals** for any under-/over-recovery of revenue that is implied.

Distribution reinforcement cost model outputs allow us to quantify **impacts on distribution network capacity reinforcement and cost**, by DNO and voltage level.

In the following sections we provide more detail on our approach for calculating these impacts.

### 2.5.1. Consumer impacts

For electricity consumers, we estimate:

- the impact of the DAM price on consumer surplus, and
- the impact of the tariffs on the consumer surplus.

Both impacts are inclusive of the demand response from different consumers (including any behind the meter generation), and the corresponding impact of this response on the system market price.

[41] We calculate the NPV of these impacts over our modelling horizon of 2024-2040 (brought forward to 2023), using the social discount rate of 3.5%.

### 2.5.2. Impacts on generation and emissions

This section describes how we capture investment/closure impacts on different generation technologies, and the corresponding potential impact on carbon emissions resulting from changes to the generation mix.

#### Investment and closure analysis under an exogenous generation capacity approach

To inform consideration of the likelihood of investment and closure of capacity, we calculate the impacts of charging options on the market revenues of different types of generation capacity net of any operational cost (such as fuel or carbon costs) and net of the relevant locational charges, by zone.

This analysis enables us to comment on the relative attractiveness of investment in different types of technology, in different locations, and at transmission voltage level relative to distribution.

For key renewable technologies, we also compare 'levelized' net revenue impacts to each generation technology's LCOE[42] to inform the likelihood of investment and closure decisions. We consider the potential for 'repowering' of onshore wind qualitatively, based on estimates of LCOE reductions suggested by stakeholders. There is a very limited evidence base from which to draw concrete estimates of the costs for repowering relative to new build capacity.

We calculate 'levelized' revenue impacts in line the BEIS methodology for calculating LCOEs[43] – i.e., taking NPV of the monetary impacts for the total assumed plant life, using the technology-specific hurdle rate, and dividing by the generation (which we also calculate on an NPV basis).

#### RES policy support and non-RES 'missing money'

Under an exogenous generation capacity approach, we implicitly assume that any revenue gap[44] that a given generation technology may face is recovered through a suitable support scheme.

In the impact assessment model, we estimate the impact of the charging option (relative to the counterfactual) on the costs of support under the CfD scheme and develop estimates of the impacts of the options on 'missing money' (i.e., revenue shortfalls) of non-RES capacity. We describe our approach below.

**CfD-type low-carbon support schemes**

We use the change in net revenues for low carbon technologies to estimate the potential impact on the extent of revenue that needs to be recovered from renewable support schemes relative to the LCOE of that technology.

Under a CfD-type support scheme with separate pots, it is reasonable to assume that each technology bids at its LCOE and is awarded a CfD contract close to that level. In other words, the LCOE is a suitable proxy for each eligible technology's likely CfD strike price.[45] As such, our revenue gap metric reflects the difference between the captured market price and the technology specific CfD strike price.

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[42] From BEIS Electricity Generation Costs 2020: https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020.

[43] See BEIS Electricity Generation Costs 2020 report: https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020.

[44] We define the 'revenue gap' as the difference between a technology's LCOE and what it is expected to earn in the market. Market revenues for each technology are estimated using outputs from the market model. For technologies that would not be eligible for RES support, the 'revenue gap' can alternatively be considered as the 'missing money' for that technology, limited to operational costs only for existing capacity rather than the full capital plus operational costs considered for new capacity (defined as any capacity built within our modelling horizon).

[45] We recognise that the applicable CfD strike price is not equal to every supported technology's LCOE given that the CfD auctions apply a uniform pricing rule, but we consider use of the LCOE to be a suitable proxy. This implicitly relies on the assumption that technologies with similar LCOEs are grouped together in pots (e.g., established vs. less established technology pots), which we consider to be a proportionate simplification for the purposes and scope of this project.

For eligible technologies where the revenue gap is zero or negative (i.e., where modelled market revenues over the year exceed the LCOE), we assume that the technology is no longer supported in the scheme or is no longer interested in bidding (with the former assumed to be more likely). In effect, these technologies no longer drive additional CfD support costs.

### Modelling missing money of non-RES plants

For non-RES capacity, we separate plant into new capacity and existing capacity:

- For new capacity, we calculate the 'missing money' i.e., any shortfall in market revenues when compared to that technology's fixed operational costs *plus annuitised capex costs*, at that technology's hurdle rate.
- For existing capacity, we do the same but only considering the 'going forward' fixed costs of that technology (effectively operating and maintenance fixed costs).

Based on these assumptions, we estimate the total missing money metric for non-RES capacity that is included in each FES scenario.

### Impacts on emissions

Our modelling only reflects electricity sector CO2e emissions rather than whole system greenhouse gas emissions – i.e., we do not reflect emissions from non-electric transport, gas used for heating, etc. As we define total capacity of each technology as fixed, CO2e is only affected by changes to demand and demand response, operational dispatch decisions and by the efficiency of the location of renewable capacity, both in terms of resource availability and as a result of re-dispatch requirements.

This allows us to comment on whether emissions levels are greater or smaller under the modelling options relative to the counterfactual. We monetise emissions (or changes in emissions relative to the counterfactual) using the traded carbon values recommended by the Green Book in its guidance for the valuation of greenhouse gas emissions for appraisal.[46]

**Box 2: Potential impacts on costs of reaching a given target on path to net zero**

We noted previously that our modelling takes generation capacity as exogenous and hence, assume that the generation capacity included in the FES is realised. This implies that carbon emission targets are reached (subject to operational generation decisions as noted above) but at a different cost, depending on the size of the revenue gap for different technologies.

An alternative interpretation is that the size of the revenue gap for low carbon technology represents the extent of risk associated with the necessary investment in the relevant technology. Where the revenue gap for low carbon technology is higher, we may assume a greater risk that the required level of installed capacity does not materialise.

Outputs from our modelling would therefore allow us to comment on the relative incentives for different types of generation and how this may support achievement of carbon emissions reduction pathways. However, it is not possible to construct a new internally consistent supply mix that reflects these incentives in full.

## 2.5.3. Impacts on constraint management costs and transmission reinforcement

As noted in section 2.3.1, we run a 'constrained' version of the market model incorporating six key transmission network constraints (i.e., transmission capacity limits between seven transmission zones). We use this specification to model:

- re-dispatch after taking into account capacity limits on the transmission network, relative to the unconstrained DAM model run,

[46] Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal, see: https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal.

- the costs of re-dispatch for constraint management purposes,[47]
- network investment at each transmission boundary.

In the impact assessment model, we estimate the impact on constraint management costs under the charging option relative to the counterfactual. We also estimate the difference in transmission network reinforcement capacity at each boundary under the charging option relative to the counterfactual, and 'monetise' this capacity investment based on annuitised[48] unit costs of network investment (i.e., in £/MW/year of asset life), which were calculated based on confidential data on reinforcement options available at each boundary, shared by the ESO.

### 2.5.4. Distribution network reinforcement costs

To estimate the NPV impact of distribution network reinforcements, we apply a capitalisation approach, in line with financial parameters set for the RIIO-ED1 price control. The process is as follows:

- First, we determine the asset value of reinforcement incurred in each year (as an output from the Distribution Network Reinforcement Model).
- We then expense a proportion of this (15% as per RIIO-ED1) in that year and capitalise the remainder.
- The capitalised proportion is annuitised using an assumed asset life of 40 years and a notional WACC.
- For the purposes of this impact assessment, the relevant cash flow metric in each year is the sum of the expensed proportion plus the annuitised cost of new assets that have entered the RAB for all investment years up to that point.
- We then calculate the present value of this cash flow over our modelling horizon, using the societal discount rate of 3.5%, in line with the calculation of the NPV for the other impact metrics derived from the market model.

This allows us to quantify impacts on distribution network capacity reinforcement costs relative to the counterfactual, by DNO and voltage level.

### 2.5.5. Bill impacts

We estimate bill impacts[49] for key consumer archetypes, after incorporating assumed changes in consumer generation and consumption behaviour that are driven by price and charging signals.

As per Ofgem's recent distributional impacts guidance, wherever data allows for such analysis, we cover the following metrics for each residential consumer archetype:

- Absolute bill impact in £ per customer,
- Bill impact as % of disposable income,
- Equity-weighted bill impact (as per the Green Book approach).

For non-domestic consumers, we only report absolute bill impacts.

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[47] As outlined in section 2.3.1, different re-dispatch actions are valued at proxy BM imbalance bid/offer prices – though we are not able to mirror the dynamics of the balancing mechanism in full.

[48] We use the electricity transmission cost of capital and relevant asset lives to annuitize the cost of network investment.

[49] Static distributional impacts (i.e., pure distributional tariff impacts on consumer archetypes, before any demand responsiveness or changes in other market dynamics) are typically estimated for impact assessments in addition to dynamic distribution impacts. There are no changes to demand tariffs under this set of policy options, so static distributional impacts are zero for all archetypes.

To estimate bill impacts for each archetype, we rely on annual consumption assumptions, adjusting this for any load-shifting observed in the market model,[50] and the £/kWh impact calculated in the impact assessment for each charging option relative to the counterfactual.

We calculate the £/kWh impact for each spot year based on its three constituent parts:

1. DAM price impacts – archetype-specific to reflect that archetype's demand profile over the year (post-load-shifting) e.g., the degree of coincidence of that archetype's demand with peak prices,
2. Applicable tariff impacts – again archetype-specific to reflect both the fact that different tariff rates apply for different archetypes in different network locations, as well as to reflect each archetype's demand profile (post-load-shifting) e.g., its degree of coincidence with peak vs. off-peak tariff rates, and
3. 'Indirect' impacts – including changes to the costs levied on consumers as part of RES support schemes and changes to missing money of non-RES plant, changes to constraint management and network capacity reinforcement costs, as well as changes to the tariff residual, as we assume that all of these impacts would ultimately be passed through to consumer electricity bills.[51]

This gives us the total absolute bill impact for each archetype, per spot year. For each domestic archetype, we divide this absolute impact by the archetype's disposable annual income to calculate the bill impact as a percentage of disposable income. We also multiply the absolute impact for each domestic archetype by that archetype's equity-weighting scaling factor, to produce equity-weighted bill impacts.

We estimate the NPV bill impact for each metric over our modelling horizon by interpolating between our three spot years and applying the social discount rate.

### Assumptions for domestic consumer archetypes

We define two sets of domestic consumer archetypes:

1. We use the archetypes developed for Ofgem by the Centre for Sustainable Energy (CSE),[52] which are intended to capture the full range of consumers in Great Britain. These are listed in Table 2.6.
2. We use Ofgem's statutory groups, to whom Ofgem must have regard when developing policy, as well as consumers included within Ofgem's Consumer Vulnerability Strategy. These are summarised as follows:
    - those with a disability,
    - those of pensionable age,
    - low-income consumers (which we define as consumers in the bottom decile of income),
    - those residing in rural areas,
    - those who are unemployed,
    - those with no internet access, and
    - single parents.

[50] This depends on technology adoption as well as behavioural response assumptions in the absence of technology. We discuss what assumptions we make in the two sections that follow.

[51] We note that the £/kWh unit impact of these costs is assumed to be the same for all archetypes. This reflects the fact that these costs feed into revenue recovery requirements that are passed on to consumers and as such are likely to impact on the level of tariffs rather than their 'peakiness'.

[52] CSE, 'Ofgem energy consumer archetypes report', see: https://www.ofgem.gov.uk/system/files/docs/2020/05/ofgem_energy_consumer_archetypes_-_final_report_0.pdf

*Table 2.6: Ofgem consumer archetypes*

| Archetype | Main attributes |
|---|---|
| A1 | High incomes, owner occupied, working age families, full time employment, low consumption, regular switchers |
| A2 | High incomes, owner occupied, middle aged, full time employment, big houses, v high consumption, solar PV, environmental concerns |
| B3 | Average incomes, retired, owner occupied - no mortgage, electric vehicles, environmental concerns, lapsed switchers, late adopters |
| B4 | High incomes, owner occupied, part-type employed, high consumers, flexible lifestyles, environmental concerns |
| C5 | Very low incomes, single female adult pensioners, non-switchers, prepayment meters, disconnected (no internet or smart phones) |
| D6 | Low income, disability, fuel debt, prepayment meter, disengaged, social housing, BME households, single parents |
| D7 | Middle aged to pensioners, full time work or retired, disability benefits, above average incomes, high consumers |
| E8 | Low income, younger households, part-time work or unemployed, private or social renters, disengaged non-switchers |
| E9 | High income, young renters, full time employments, private renters, early adopters, smart phones |
| F10 | Middle aged/pensioners, full time/retired, owner occupied, higher incomes, oil heat, rural, environmental awareness, RHI, late adopters |
| G11 | Younger couples/single adults, private renters, electric heat, employed, average incomes, early adopters, BME, low engagement |
| H12 | Elderly, single adults, very low income, medium electricity consumers, never-switched, disconnected, fuel debt |
| H13 | Off gas, low income, high electricity consumption, disability benefits, over 45s, low energy market engagement, late adopters |

For all archetypes, we use disposable income data and equity-weightings provided by Ofgem. We also take current typical annual consumption data for each archetype from Ofgem. We then use the FES scenario demand growth projections to extrapolate demand levels for each of these consumer archetypes over our modelling horizon. Demand growth trajectories in the FES vary for different residential consumer types based on technology take-up over time.

For the early years of our modelling horizon, we rely on the attributes of different consumer archetypes as defined in Ofgem's consumer archetype report[53] to define uptake of different consumer technologies by each archetype. However, it is important to note that these archetypes are defined for existing consumers as of today. Under our modelled FES scenarios, all archetypes will change preferences and behaviours significantly by 2040. For example, we note that only one of the archetypes defined in the report (B3) explicitly includes the adoption of electric vehicles.

To consider potential bill impacts on different archetypes, we therefore needed to develop assumptions about which archetypes would be more likely to adopt technologies, such as EVs and heat pumps over time.

We include these assumptions in the table below.[54] Our rationale for these assumptions is based on the total uptake assumed for each technology in the FES for domestic households under each scenario and the following rules of thumb for determining the relatively likelihood/ranking of archetypes taking up each technology:

- We proxied the likelihood of adoption of rooftop solar and micro-battery technologies on the ranking of archetypes by disposable net household income. In the absence of explicit adoption of these technologies, we allowed for some 'non-optimising' (see section 2.3.3) behavioural response on level of that archetype's engagement with the energy market based on evidence of switching.
- We proxied the likelihood of adoption of electric vehicle technologies on the current percentage of households within each archetype that have taken up electric vehicles, scaled up to reflect the assumed uptake for the GB population as a whole in each spot year.
- We proxied the likelihood of adoption of heat pumps on the ranking of archetypes by disposable net household income (subject to the total uptake in the GB population assumed in the respective FES scenarios). We also implemented some manual adjustments based on the qualitative characteristics of the

[53] CSE, 'Ofgem energy consumer archetypes report', see: https://www.ofgem.gov.uk/system/files/docs/2020/05/ofgem_energy_consumer_archetypes_-_final_report_0.pdf

[54] The CSE Ofgem archetypes are designed to represent the whole GB population. As such, we make scenario-specific assumptions for these archetypes, aligned with the percentage uptakes of each technology assumed in the FES for domestic households under each scenario. The assumptions shown in this table are for our central 'CT' scenario.

archetypes – e.g., archetypes identified as likely to have invested in low-carbon heating because of environmental concerns were ‘assigned’ heat pumps earlier than renters who we assumed were less inclined to acquire heat pumps regardless of their position in the income ranking.

*Table 2.7: Technology up-take assumptions for each domestic archetype*

| | 2024 | 2029 | 2040 |
|---|---|---|---|
| *CSE Ofgem archetypes* | | | |
| A1 | Rooftop solar installed, with some households also installing micro-batteries by 2024 | | |
| | | | Electric vehicle with smart-charger post 2029, and for a subset of consumers also V2G |
| | | Heat pump installed (along with thermal storage for some households) by 2029 | |
| A2 | Rooftop solar installed, with some households also installing micro-batteries by 2024 | | |
| | | Electric vehicle, with smart-charger, and for a subset of consumers also V2G by 2029 | |
| | Heat pump installed (along with thermal storage for some households) by 2024 | | |
| B3 | No solar/battery, and no behavioural response in 2024 | No solar/battery, but some 'non-optimising' behavioural response by 2029 | |
| | Electric vehicle | Electric vehicle, with smart-charger, and for a subset of consumers also V2G by 2029 | |
| | No heat pump | | |
| B4 | No solar/battery, and no behavioural response in 2024 | Rooftop solar installed, with some households also installing micro-batteries by 2029 | |
| | No electric vehicle | | |
| | | Heat pump installed (along with thermal storage for some households) by 2029 | |
| C5 | No solar/battery, and no behavioural response | | |
| | | Electric vehicle, with smart-charger, and for a subset of consumers also V2G by 2029 | |
| | No heat pump | | |
| D6 | No solar/battery, and no behavioural response | | |
| | No electric vehicle | | |
| | No heat pump | | |
| D7 | No solar/battery, and no behavioural response | No solar/battery, but some 'non-optimising' behavioural response | |
| | | Electric vehicle, with smart-charger, and for a subset of consumers also V2G by 2029 | |
| | No heat pump | | |
| E8 | No solar/battery, and no behavioural response | | No solar/battery, but some 'non-optimising' behavioural response |
| | No electric vehicle | | |
| | No heat pump | | |
| E9 | No solar/battery, and no behavioural response | | Rooftop solar installed, with some households also installing micro-batteries |
| | No electric vehicle | | |
| | No heat pump | | |

| | 2024 | 2029 | 2040 |
|---|---|---|---|
| F10 | No solar/battery, and no behavioural response | No solar/battery, but some 'non-optimising' behavioural response | Rooftop solar installed, with some households also installing micro-batteries |
| | | Electric vehicle, with smart-charger, and for a subset of consumers also V2G by 2029 | |
| | Heat pump installed (along with thermal storage for some households) by 2024 | | |
| G11 | No solar/battery, and no behavioural response | | No solar/battery, but some 'non-optimising' behavioural response |
| | No electric vehicle | | |
| | No heat pump | | |
| H12 | No solar/battery, and no behavioural response | | |
| | No electric vehicle | | |
| | No heat pump | | |
| H13 | No solar/battery, and no behavioural response | | No solar/battery, but some 'non-optimising' behavioural response |
| | No electric vehicle | | |
| | No heat pump | | |
| *Statutory archetypes* | | | |
| Low income (defined as bottom decile of disposable income) | No solar/battery, and no behavioural response. No electric vehicle or heat pump. | | |
| Pensionable age | No solar/battery, and no behavioural response. No electric vehicle or heat pump. | | |
| Disabled | No solar/battery, and no behavioural response. No electric vehicle or heat pump. | | |
| Rural areas | Rooftop solar installed, with some households also installing micro-batteries by 2024 | | |
| | No electric vehicle or heat pump.[55] | | |
| No internet access | No solar/battery, and no behavioural response. No electric vehicle or heat pump. | | |
| Unemployed | No solar/battery, and no behavioural response. No electric vehicle or heat pump. | | |
| Single parents | No solar/battery, and no behavioural response. No electric vehicle or heat pump. | | |

### Assumptions for non-domestic consumer archetypes

We also assess impacts on different types of non-domestic consumers.

Our analysis considers:

- Very small commercial customers connected to the LV network with average annual consumption of 6.7 MWh (based on the GB-wide median of commercial consumer demand[56]).
- Small commercial customers connected to the HV network with average annual consumption of 61.9 MWh (based on GB-wide mean of commercial consumer demand).

[55] Rural consumers are assumed to install a mixture of rooftop solar plus battery and biomass boilers rather than heat pumps for the purposes of the bill impact analysis. The archetype with the highest proportion of rural consumers in the CSE Ofgem archetypes (F10) is noted to include households that are likely to invest in renewable heat – in that case we have assumed that heat pumps are installed early on. We also assume that this archetype takes up an EV by 2029. We consider that this differentiation is a good proxy for the natural variation likely to be observed amongst rural consumers.

[56] For commercial customers, we define our representative archetypes based on the BEIS Sub-national electricity sales dataset (2020). The distribution of commercial customers in this dataset is positively skewed, with the majority of customers being 'very small' and with a few larger commercial consumers included, pushing up the mean. As such, we use the median to represent a typical 'very small' commercial consumer, and the mean to represent a typical 'small' commercial consumer.

- Medium to large commercial/industrial consumers connected to the EHV network with average annual consumption of around 40.6 GWh (based on the mid-point of the medium and large consumption bands).
- Very large industrial consumers connected directly to the transmission network with average annual consumption of around 135.0 GWh (based on the mid-point of the very large consumption band).
- An example fleet EV consumer with 25 electric vehicles with annual consumption of just over 163.9 MWh.[57]
- An example fleet EV consumer with 50 electric vehicles with annual consumption of just over 299.2 MWh.[58]

For each non-domestic archetype, we assume a demand growth trajectory in line with our modelled FES scenarios over our modelling horizon. We also assume technology adoption rates for each archetype in line with the FES scenarios. This includes non-domestic heat pump, solar PV, battery or other onsite generation average uptake rates per commercial or industrial archetype and smart-charging and V2G uptake rates for fleets.

[57] We take annual consumption for each vehicle from our modelled FES scenario.

[58] We take annual consumption for each vehicle from our modelled FES scenario.

# 3. TARIFF OPTIONS MODELLED

We perform all modelling for each of the options packages developed by Ofgem and compare outcomes against a counterfactual option run in which no changes to policy are assumed.

In the following sections, we summarise our modelling approach for the counterfactual and for modelling of the two sets of options packages:

1. Applying TNUoS charges to embedded generators, and
2. DUoS connection boundary options

## 3.1. Modelling of the counterfactual

In Table 3.1 we set out our definition of the counterfactual.

*Table 3.1: Description of counterfactual*

| Policy workstream | Description |
|---|---|
| **DUoS charge design** | • **Small demand users:** Static ToU (3 RAG bands, not seasonal) plus a fixed residual charge element (as per TCR).<br>• **Large demand users:** Static ToU (3 RAG bands, not seasonal), agreed capacity charge (as per MIC in connection agreement) and exceeded capacity charge, plus a fixed residual charge (as per TCR) and reactive power element. The capacity charges and the reactive power element are not included in our impact assessment modelling framework.<br>• **Generation:** Static ToU (3 RAG bands, not seasonal) but charges are the negative of demand. There are no capacity charges. There is a reactive power charge if the power factor < 0.95 but this is not incorporated into the market model framework. |
| **DUoS cost model** | The CDCM and EDCM rely on different cost models:<br>• A 500MW model for the CDCM<br>• A Long Run Incremental Cost (LRIC) model or Forward Cost Pricing (FCP) methodology for the EDCM, depending on the DNO.<br>    ○ As LRIC and FCP costs are confidential, CEPA/TNEI (DCUSA contract) approximate these using locational forward-looking outputs from the cost model subgroup. |
| **Locational granularity** | None for CDCM<br>Site-specific for EDCM. |
| **TNUoS** | **Small demand users:** Static ToU charge (4-7pm); 14 demand zones.<br>**Large demand users:** Winter only triads; 14 demand zones.<br>**Generation:** Generation charges apply to transmission-connected generators,[59] depending on TNUoS technology type (Intermittent, Conventional Low Carbon or Conventional Carbon), annual load factor of each technology and T-zone.[60] Demand TNUoS charges apply to distribution-connected generators (specific to each of the 14 D-zones), with credits for exporting during triads (through the Embedded Export Tariff). |

[59] See Table 2.4 for further details the types of generators included in this group and the potential impacts of our simplified representation of the applicability of generator charges.

[60] For each of our seven transmission zones, we take weighted averages of the relevant 27 TNUoS generation zone tariffs, using weights provided by the ESO.

| | |
|---|---|
| **Connection charges** | A shallow-ish connection charge approach applies under which users contribute for reinforcement of the voltage level to which they connect, as well as the voltage level above. |
| **Access rights** | There are no Access Rights options within the counterfactual. |

### 3.1.1. Application of TNUoS charges

For the counterfactual, we follow the methodology set out by the ESO to define the charges levied on different user types.[61] We summarise this application below:

- **Producers who pay Generator TNUoS**[62] face charges which depend on their technology classification (Intermittent, Conventional Low Carbon or Conventional Carbon). See Figure 3.1 for a summary of the application of charges to these different types of producers. The figure shows that some charges are partly determined by the annual load factor (ALF) of the producer. In theory at least, this may introduce some form of dispatch signal as a reduction in annual dispatch would lead to a lower charge. However, in practice, the highest and lowest annual load factors from the previous five years are discounted such that the ALF is determined based on the load factor in the central three of the previous five years. The dispatch signal is therefore dampened and unlikely to impact significantly on producer behaviour. We therefore model all elements of Generator TNUoS as a capacity-based signal.

- **Half-hourly settled demand customers**[63] face locational Demand TNUoS with charges according to their average demand over the three Triad periods with the highest net system demand in each year. In Scotland and the north of England and Wales, Demand TNUoS is negative[64] which introduces an incentive to increase demand during these periods. We model this signal directly – i.e., there is an incentive for consumers to avoid/increase demand during Triad periods where they are able to do so.

- **Non-half hourly settled customers** face locational Demand TNUoS based on their annual consumption between 4-7pm as a 'targeted' volumetric tariff within these hours. In Scotland and the north of England and Wales, Demand TNUoS is negative which introduces an incentive to increase demand during these periods. We model this signal directly – i.e., there is an incentive for consumers to avoid/increase demand during the 4-7pm period where they are able to do so.

- **Under the current arrangements, embedded generators with capacity of less than 100 MW**[65] **receive the embedded export tariff (EET) credit.** The EET is paid as a credit to embedded generators based on their half hourly metered export during Triad periods. The EET is capped at zero. This means that in Scotland and the north of England where a positive charge would otherwise apply (i.e., not a credit), there

[61] For an accessible overview of the application of TNUoS charges, see the ESO's 'TNUoS in 10 Minutes': https://www.nationalgrideso.com/document/130271/download

[62] This includes both generators that are directly connected to the transmission network and large-embedded generators (with capacity greater than or equal to 100 MW and with a BEGA).

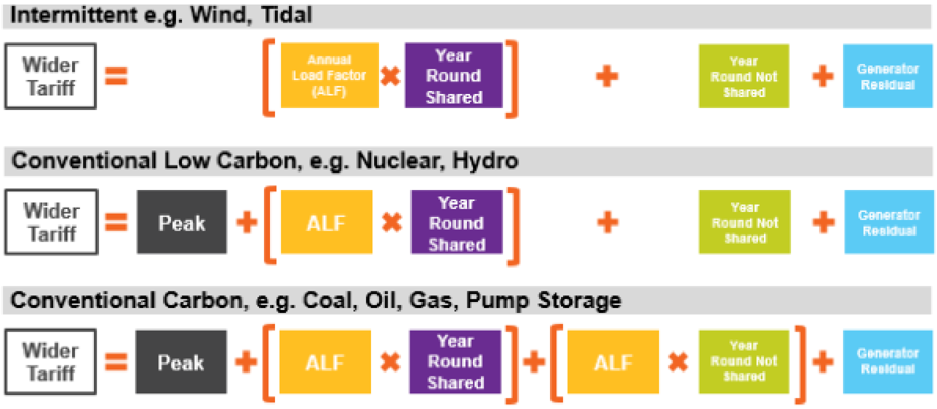
[63] As a result of modifications CMP266 and CMP318, we note that small customers (i.e. domestic and smaller non-domestic customers) that are half-hourly settled would continue to be charged under the non-half hourly settled arrangements described below. This means that the 'half-hourly settled demand customers' category effectively means 'large customers' regardless of settlement status.

[64] We note that Ofgem's Minded-to Decision on the Targeted Charging Review specifies that the locational element of the Demand TNUoS charge would be floored at zero. We understand that this change would apply equally to gross demand (i.e., not affecting changes to the EET) under both the counterfactual and the policy option such that the analysis set out in this report would be largely unaffected.

[65] This includes both small-embedded generators (with capacity of 1MW or greater) as well as micro-generators (with capacity less than 1MW).

is currently no Generator TNUoS charge for embedded generation. Due to uncertainty regarding the exact timing of Triad periods, these charging arrangements introduce incentives to dispatch not only in actual Triad periods, but also in ***expected*** Triad periods. We model Triads probabilistically in order to reflect these dynamics.[66]

*Figure 3.1: Application of charges to different classifications of producer*




*Source: ESO, 'TNUoS in 10 Minutes'*

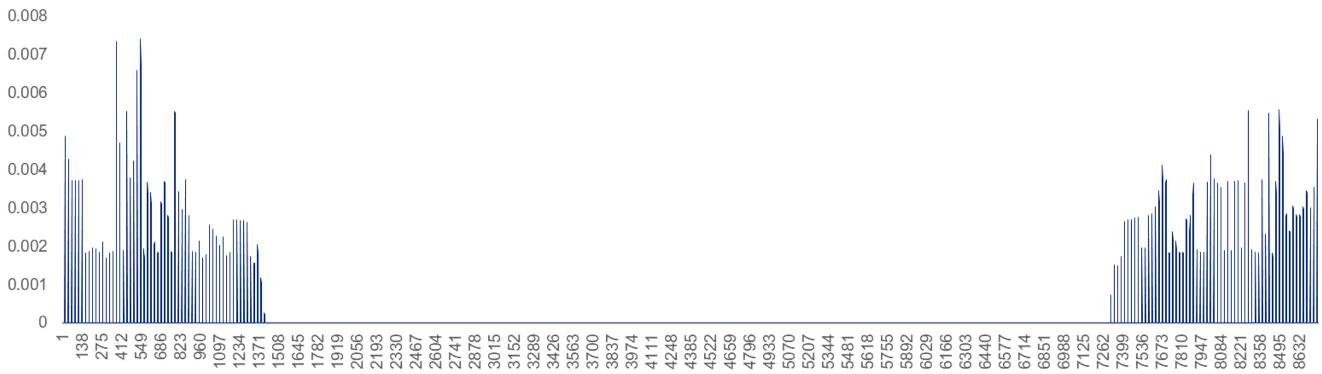
## Probabilistic approach to modelling Triads

We calculate a probability profile for the likelihood of triads occurring on each hour of each winter day.[67]

Our probability profile is based on historical triad occurrences since 1990, and the ex-post triads that would have occurred using the exogenous demand profiles we utilise in the market model in each spot year, before any endogenous demand or behind the meter generation response.

Triads have not occurred historically outside the 4-7pm period. To ensure that our probabilistic profile is realistic, we have restricted Triad occurrence to those hours on each day between November and February of each spot year. Figure 3.2 shows our assumed probability profile, based on exogenous demand profiles utilised in modelling our first spot year (2024).

*Figure 3.2: Assumed probabilistic triad likelihood profile*




Note that this profile sums to 1 over each calendar year, to reflect the fact that triad tariffs are charged on the *average* consumption during the ex-post three half-hour settlement periods with highest system demand.[68]

We apply this approach in both the counterfactual and the option packages.

[66] See our accompanying Methodology Note for more detail on our approach for modelling of Triads.

[67] Summer hours are explicitly excluded, in line with policy – i.e., a zero probability of Triad occurrence was assumed for these.

[68] Separated by at least 10 calendar days.

## 3.2. Modelling of options packages

### 3.2.1. Applying TNUoS charges to embedded generators

Under Ofgem's proposed reform option, we are modelling two key changes to these arrangements:

- For small-embedded generators (with capacity of 1MW or greater): The charging structure changes. The EET credit is removed and replaced with Generator TNUoS (assumed to be a capacity-based charge). This means that charges are no longer floored at zero such that embedded generators would face a charge where Generator TNUoS is positive.
- For micro-generators (with capacity less than 1MW): The charging structure will remain the same but the floor of zero on the EET is removed. In zones where the charge is currently set to zero, micro-generators will face a positive charge (rather than receiving a negative charge, i.e., credit) for export during Triad periods.

### 3.2.2. Connection boundary options

Our modelling focusses on the direct impacts of reforms to the connection boundary on the costs of the distribution network. Several of Ofgem's anticipated benefits of this reform are not possible to quantify within this modelling framework. For example, Ofgem anticipate the potential for reform of the connection boundary to make it easier for low-carbon technologies to connect to the distribution network. In this sense, it is important to note that our modelling provides only a part of the picture. It is intended to inform Ofgem's principles-based assessment by estimating the network cost impacts and allowing Ofgem to consider whether any additional network costs are likely to be outweighed by broader, non-quantifiable benefits.

#### Approach

Impacts of connection boundary options have been assessed predominantly within our distribution network model. This model includes an estimate of the locational investment decisions that will be made for new capacity within a distribution network zone, which is determined by signals provided through connection charges and any locational elements of DUoS charges. By varying the modelled depth of the connection boundary and incorporating different DUoS approaches it is possible to estimate how these policy reforms could affect the need for distribution network reinforcement between 2023 and 2040.

For consistency between connection boundary options, we use a single run of the market model (for each scenario) to generate the inputs for all options. We use the counterfactual run that does not incorporate any other change to tariff design such that the impacts of the proposed connection boundary reforms can be considered independently. The model considers import and export requirements from the network in six seasonal/time-of-day time bands (peak, day and night, each for summer and winter).

#### Connection boundary options

We reflect four different connection boundary options within the model:

1. Under the **shallow-ish counterfactual**, the model reflects the existing voltage rule. This states that users contribute for reinforcement at the voltage level to which they connect, as well as the voltage level above.
2. The first policy option **amends the voltage rule** such that customers only face connection charges for reinforcement for the voltage level to which they are connected. Contribution to higher voltage levels is no longer required.
3. The second option is a **hybrid option**, which removes connection charges completely for demand (i.e., a shallow connection boundary), and retains connection charges for generation but including the amended voltage rule mentioned above.
4. The final option introduces a **shallow connection charge**, removing all connection charges associated with reinforcement.

Our model only incorporates the shared elements of the network such that the costs of sole use assets are not included. A completely shallow connection boundary therefore includes no connection charge for the connectee in our modelling, only the element which is shared through DUoS.

## DUoS options

We have modelled the four connection boundary options against two different DUoS "backgrounds".

1. The counterfactual status-quo CDCM and EDCM charges.
2. Charges set using a notional version of a possible DUoS policy change.

The assumptions about how DUoS charges are set interact heavily with the modelling of connection boundary options, since it is ultimately the balance between connection charges and locational DUoS which signals to a user where on the network, they should choose to locate their new capacity.

In the DUoS counterfactual, charges do vary by voltage level but, apart from this, are assumed not to affect locational decisions. In practice, EDCM charges *do* vary by location, but we understand that these are rarely accounted for within locational decisions as they are too volatile to provide a stable signal. Therefore, the model considers the average EDCM import and export charge for each voltage level within each distribution network zone as part of the locational decision-making process.

The notional policy option is one specific combination of features that Ofgem has been considering as part of an "ultra-long-run" cost model, which would ultimately replace both the CDCM and EDCM. This uses locationally specific estimates of network asset value and utilisation to drive locational DUoS charges. The notional option used within this modelling has the following features:

- The £/kVA/year locationally specific unit costs are initially averaged across all voltage levels, such that users are not exposed to signals that reflect any deviation away from average costs of capacity (e.g., due to very long or short overhead lines or cables).
- No "spare capacity indicator" is used. This means there is no signal for users to favour areas of the network which currently have more capacity.
- While the total £/kVA/year cost for each location is the same (within each voltage level) the allocation of costs to time bands (and demand vs generation dominance) may be different for each location.
- This allocation to time bands is initially done for each primary substation but, as a final step, £/kVA/year costs for each time band are averaged across each Bulk Supply Point (BSP) or Grid Supply Point (GSP) group.

It is important to note that this DUoS policy option is only used for the purposes of assessing the connection boundary reforms against a revised DUoS charging background. It does not reflect Ofgem's policy intentions for DUoS reform under the Access and Forward-Looking SCR.

## Limits and constraints on locational decision-making

Our modelling can estimate the way in which DUoS and connection charges will affect the locational decisions made by users about where to site new demand and generation capacity. However, these charges are only one, potentially small, part of the complicated set of factors that would inform these decisions. For example, for embedded renewable generation, locational decisions will be strongly influenced by the energy yield (e.g., the wind or solar resource at each location), the ability to get planning permission (which may be significantly more challenging in certain locations), and other factors like accessibility.

Modelling these other factors is outside of the scope of this analysis. This may lead to our model overestimating the extent to which connection charges and DUoS drive locational decision making. In addition, there are other aspects of connection charging policy which we have not modelled (such as the high-cost cap) or have modelled in a relatively simple way (such as cost apportionment factors). There may even be other signals provided by a DNO to users which influence where to connect, such as indications of where there is more spare capacity available for new connections.

To address these limitations, we have incorporated a set of assumptions and constraints within the model to avoid outcomes that may be unrealistic. These are described in Section 2.4.8.

# Appendix A BEHAVIOURAL LITERATURE REVIEW FINDINGS

## Summary of literature reviewed

CEPA has reviewed over 90 studies and trial results on consumer responses to electricity tariff charging arrangements to inform our behavioural assumptions. These studies consist of commercial trials, academic studies and regulatory reviews. CEPA's review covers 55 trials that present load shifting results and 19 containing changes in total consumption. Most trials have taken place in the UK, continental Europe, North America or Australia. Where possible, we have identified findings specific to the set of consumer archetypes and relevant to the UK. The key findings of this review inform our assumptions of consumer behaviour, which are used as inputs to the modelling framework.

Most of the studies CEPA reviewed involve trials of ToU tariffs applied to the 'whole retail bill' rather than focussing solely on the network charge element. Our review focuses on simple time-varying charge options. We have assessed trial results for implications of load shifting, where users reduce peak period usage, and peak shaving, where reduced peak usage transfers into lower total consumption. We have placed emphasis on trials with statistically significant results, appropriate trial designs, and studies that are regionally relevant to the UK. Note that many relevant trials have small sample sizes and often lack statistically significant results, leading to difficulty in determining reliable inference across some individual user archetypes.

## A.1. KEY FINDINGS

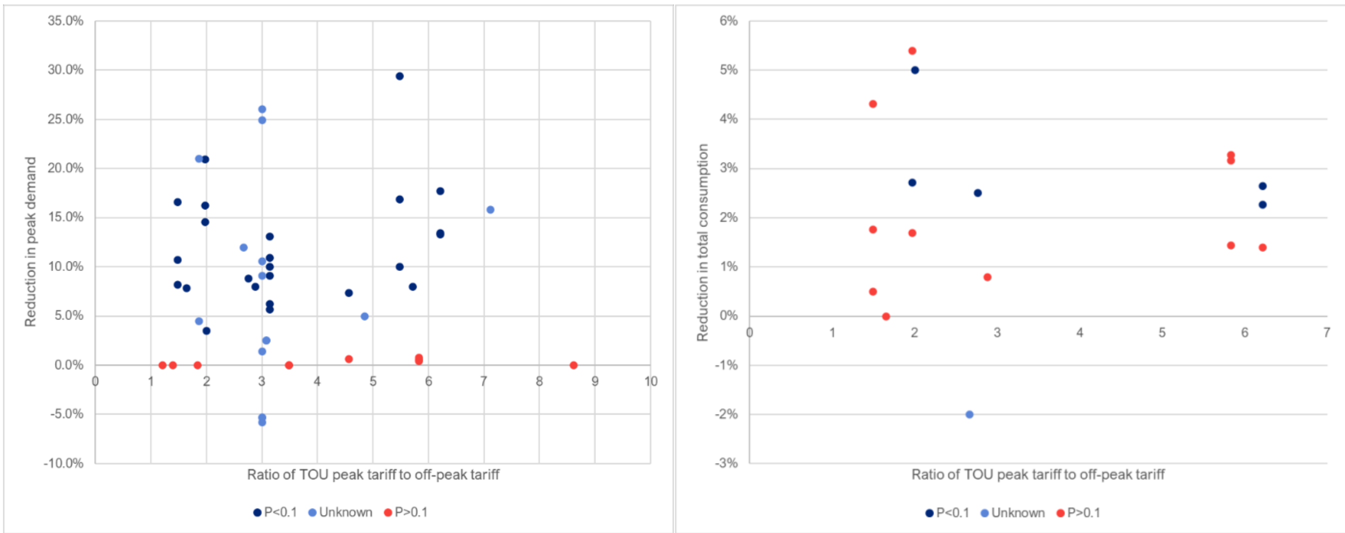
### A.1.1. General results

There is strong evidence that domestic consumers reduce peak electricity demand and total electricity consumption in response to ToU tariffs (Figure A.1). An average domestic consumer reduces their peak demand by 8% and their total consumption by 2%, responding to time-varying tariffs.

Consumer responses vary depending on the size of the price signal, the type of consumer, and access to enabling technology. The largest percentage response in peak demand was a 29% reduction, while many trials reported no statistically significant change in consumption and even peak demand increases of up to 5% peak demand. There is less variation in percentage terms among changes in total consumption, which range from a 5% reduction in total electricity demand and a 2% increase.

Trial results indicate that behavioural responses can be partially attributed to non-price related factors. Responses depend on the differential between 'off-peak' and 'peak' charges, with large differences tending to result in larger responses. However, trial results show there is no clear linear relationship between larger peak: off-peak ratios and larger responses. This means that factors aside from price signals affect electricity consumption behaviour.

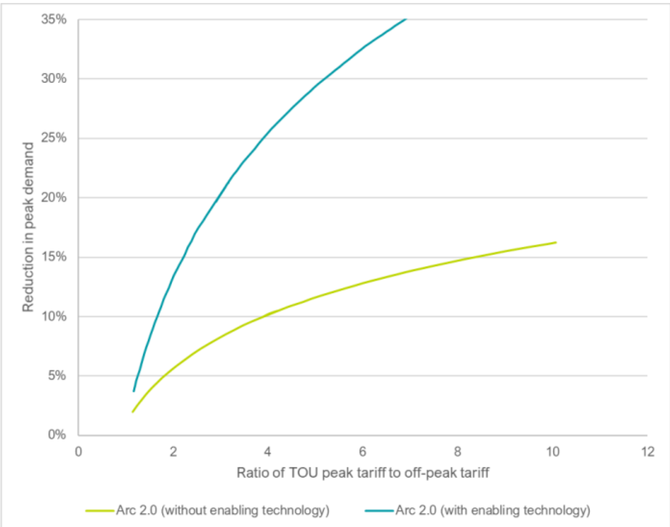
*Figure A.1:* Domestic responses to ToU tariffs split by statistical significance, load shifting (left) and peak shaving (right)




In addition to individual trials, the Arcturus curves from the 2017 Faruqui et al. meta-study are a key piece of evidence on domestic consumer responses to time-varying tariffs. The study assesses the results of more than 350 ToU trials to determine the relationship between load shifting responses and the size of ToU price signals.

Figure A.2 presents the Arcturus 2.0 curve for trials with and without enabling technology, using peak: off-peak tariff ratio as a metric of the price signal. According to the study, at a peak: off-peak price ratio of 2:1 a user without enabling technology consumes 95% of their typical peak usage, while a user with enabling technology consumes 91%. At a price ratio of 4:1 this effect increases to 90% and 75% of typical peak usage, respectively.

*Figure A.2: Arcturus 2.0 curves*




*Source: Faruqui et al. (2017)*

### A.1.2. Load shifting versus peak shaving

The literature exhibits more evidence of consumers' load shifting rather than peak shaving or adjusting their total consumption in response to ToU tariffs. Eight of the 53 trial results on load shifting (15%) exhibited statistically insignificant results. For trials that considered changes in total consumption, we found that 11 of the 18 trials (61%) indicated no statistically significant change in overall consumption. We assume that, in response to time-varying tariffs, consumers elicit time of use behavioural changes but do not adjust their overall consumption. This aligns with our prior expectations which suggest that residential and small commercial consumers shift electricity consuming activities away from peak rather than forgoing them altogether.

### A.1.3. Behavioural user archetypes for the review

Our modelling incorporates a set of behavioural archetypes, with each represented independently in the model based on whether they are likely to demonstrate a different nature of behavioural response. As part of our literature review, we have considered the extent of evidence of different behavioural responses of different types of consumer.

Most behavioural response trials we assessed use a random sample of domestic households and present results as the average response of aggregated domestic users.

Where possible, CEPA has identified trials that present results for individual user archetypes. However, the number of trials with suitable results is much smaller relative to that at the aggregated level. There is a large enough sample of trial results for the EV charging and vulnerable user archetype estimates to warrant a higher level of confidence in the findings. The smaller set of results for solar PV, heat pumps, and commercial consumers means that we have more limited confidence in these estimates.

Table A.1: Load shifting response index, 100 = average domestic consumer response presents an index of behavioural responses of each user archetype, using the average domestic consumer response as the base. The average load shifting response for domestic consumers is 8.3% of peak demand, as presented in Section A.1.1.

*Table A.1: Load shifting response index, 100 = average domestic consumer response*

| Archetype | Trial results (no.) | Load shifting (%) | Maximum (%) | Minimum (%) | Confidence |
|---|---|---|---|---|---|
| Aggregated domestic users | 59 | 100 | 350 | -70 | High |
| EV charging | 7 | 311 | 807 | 90 | Medium |
| Households with solar PV | 2 | 78 | 120 | 36 | Low |
| Vulnerable households | 6 | 65 | 100 | 22 | Medium |
| Commercial users (low consumption) | 2 | 27 | 27 | 0 | Low |

Under time-varying tariffs, domestic consumers with EVs consistently reduce peak period EV charging at a greater rate than the average household reduce overall peak demand use. Consumers regularly make use of enabling technology, such as charging timers and smart charging, when available. In the UK, Octopus Energy found that EV customers on real-time pricing reduced their peak demand usage by 47%.[69] Other trials from North America show ToU charges for EV consumers can reduce peak period EV charging by between 8% and 23%.[70, 71]

The Kaluza ToU DUoS trial under UKPN's Project Shift shows further potential peak load reductions for EV charging when automated smart charging is used. Participants in the Kaluza trial reduced their peak period EV charging by up to 67% according to the July 2020 interim results.[72] Other than the Kaluza trial, there were no explicit uses of smart charging and/or vehicle to grid technology in the trials CEPA took behavioural response data from. However, we assume all participants have access to charging timers, which are common features in EV and charger apps.

For solar PV trials we have exclusively considered trials that are based in the UK or regions with similar climates due to the importance of solar irradiance in solar PV uptake and generation. Solar PV consumer are less responsive than the average domestic consumers, but this may result from a lower peak period demand base. Consumers with solar PV installations and battery storage tend to have lower base levels of peak period demand when on non-time-

[69] Octopus Energy (2019) Agile Octopus: A consumer-led shift to a low carbon future

[70] Xcel Energy (2018) Compliance filing: Residential electric vehicle charging tariff

[71] Zanikau et al. (2015) How will tomorrow's Energy consumer respond to price signals? Insights from a Texas pricing experiment

[72] UKPN (2020) Shift Interim Project Report

varying charging arrangements.[73] This means that PV households have less available peak demand to shift, which partially explains the smaller relative response of solar PV users.

Studies on vulnerable households, defined as low-income or fuel-poor consumers, show that these consumers are either as responsive as or slightly less responsive to ToU tariffs than the average household. A 2010 meta-study on ToU tariffs by Faruqui et al. indicates that low-income household peak load shifting responses do not vary from the average in some trials, while in others they elicited a response that was 15 to 78 percent less than the average.[74]

Commercial consumers with low consumption are often less responsive to ToU tariffs than domestic consumers. The 2011 Electricity Smart Metering Customer Behaviour Trials by Commission for Energy Regulation in Ireland found that this band of commercial consumers found it difficult to adjust hours of energy usage while maintaining business operations.[75]

Households with heat pumps are not included in Table A.1 due the limited number of relevant and statistically significant behavioural response trials, but there are studies that provide useful insights. A 2017 study on heat pump electricity load profiles by Love et al. shows that a 20% uptake of heat pumps could increase the GB national grid evening peak by 14%.[76] Additionally, a simulated ToU trial in the Greater Manchester area suggests domestic households with heat pumps could reduce day time demand by 62%, albeit with direct control over the heat pumps.[77] These studies indicate that the uptake of heat pumps will increase peak demand relative to the UK average but could be offset by the day time reduction potential of implementing ToU tariffs with automation.

### A.1.4. Impact of technology

The provision of enabling technology and automation noticeably increases the size of behavioural responses. Figure A.3 captures trial results by access to assistive technology. On average, consumers with enabling technology, such as in-house displays (IHDs), shift load from peak periods by an additional 4% and reduce total consumption by an additional 1% compared to consumers without enabling technology. Access to some form of automation has the potential to increase load shifting responses four-fold relative to consumers without any enabling technology.

[73] According to the Northern Powergrid DS3 study, peak demand among households with solar PV is 18 to 55% lower than the average household.

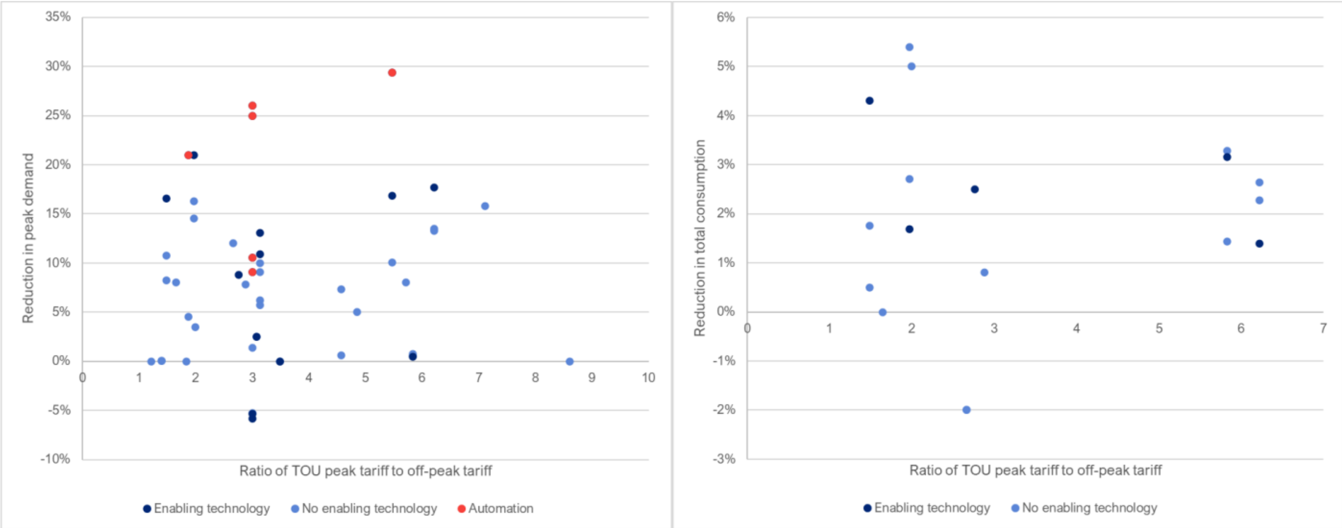
[74] Faruqui et al. (2010) The impact of dynamic pricing on low-income customers

[75] CER (2011) Electricity Smart Metering Customer Behaviour Trials (CBT) Findings Report

[76] Love et al. (2017) The addition of heat pump electricity load profiles to GB electricity demand: Evidence from a heat pump field trial

[77] New Energy and Industrial Technology Development Organization (NEDO) (2017) Implementation Report for Smart Community Demonstration Project in Greater Manchester, UK

*Figure A.3: Domestic consumer responses to ToU tariffs split by level of access to technology, load shifting (left) and peak shaving (right)*




*Source: CEPA analysis of behavioural literature*

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