ASSESSING THE POTENTIAL VALUE FROM DSOS

A report to Energy Systems Catapult

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Contact details

Name	Email	Telephone
Gareth Davies	gareth.davies@poyry.com	+44 1865 812 204
David Cox	david.cox@poyry.com	+44 1865 812 223
John Perkins	John.perkins@poyry.com	+44 1865 812 252

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EXECUTIVE SUMMARY

Decarbonisation and technological advances are transforming the electricity sector in regards to both generation and demand. The emerging system is creating new risks and opportunities for distribution networks. To manage these risks and opportunities more Distribution Network Operators (DNOs) are beginning to transition into a Distribution System Operators (DSOs) model. In particular, there will be scope to reassess how actively DSOs are able to utilise the flexibility resulting from the decentralised resources connected to their networks.

Our study aims to contribute to this debate through analysing the extent to which different approaches impact on the potential value of flexibility to the electricity system and the role of DSOs.

Future market architecture

We have developed a set of Frameworks which represents a potential future architecture focused on the DSO and TSO interactions. Through these Frameworks, we characterise how flexibility can be used by various market participants and the extent to which this leads to benefits for that specific participant, and the market as a whole.

The starting point for our analysis is the Two Degrees scenario from National Grid’s 2018 Future Energy Scenarios (“FES”). This represents the FES scenario with the highest level and fastest speed of decarbonisation in the GB system; the decarbonisation target is met using larger and more centralised technologies. This scenario was chosen to focus the modelling around a world in which these targets are successfully met.

Within the context of the Two Degrees scenario, the assessment focussed on how the distribution system will function. This involved mapping the system described in this scenario into a high-level, characteristic distribution network model, and to assess the impact of the different Frameworks.

Key findings

The key findings associated with our assessment are set out below. The results show that there is opportunity for significant savings by moving towards new market structures. Further detail on each of the concluding comments below can be found in Section 4 of this report:

- **Impact of diverging peaks can lead to inefficient solutions**. The lack of coincidence between local and national peaks leads to the possibility of inefficient system solutions when the same resource can be used to address network issues at both levels, with impacts on costs increasing over time. However some demands, such as the electrification of heat and transport will also be the source of the additional flexibility. As a result this demand and flexibility will arrive at the same time and in the same location.
- **Local flexibility resources should be used at the local level**. There is a higher value from using local flexibility resources to address local network issues (due to lack of alternative options).

- **Network investment is the main driver of cost differences across our Frameworks**. The 'Current Position' Framework features the highest cumulative total system cost at £563bn, over £7.2bn more expensive than the 'Perfect Information' Framework.
- **Revealing the true value of flexibility to the distribution or transmission system will deliver the greatest benefits**. However these require more fundamental changes in information/data flows, commercial arrangements and regulatory incentives.
- **The 'Frameworks' share many of the same features**. Therefore it should be possible to transition from one to another without too much disruption.

Recommendations

Our conclusions have led to the following recommendations. Further detail on each of the recommendations can be found in Section 4.2 of this report:

- **A phased change in the TSO-DSO Framework may be more appropriate given the uncertainty over the speed and extent of the wider decarbonisation programme**. This transition between the Frameworks will need to reflect the status of the electricity market at any point in time, but must be flexible enough to react to market developments:
  - Phase 1 of the transition should look to establish a Framework where the TSO can coordinate more effectively between the needs of local DSOs and the national system. The information exchanges between DSO and TSO and the observations of the impact of the use of flexible resources at particular times will improve transparency and knowledge of the costs and value of individual resources.

  Phase 1 corresponds to the period prior to anticipated load growth reaching the point of driving the need for widespread network reinforcement or the use of flexibility, which the FES shows happening from 2030 onwards
  - Phase 2 is most likely to occur from 2030 onwards. This is when significant load growth is anticipated and hence there are much greater savings in distribution investment if the DSO is influencing the location of embedded generation. This transition is less certain and when it does occur it may follow different paths though both will come as electrification accelerates and the ability of the TSO to coordinate reduces due to ongoing information asymmetries between the TSO and DSOs:
    - In Phase 2a, the greater transparency to DSOs of the flexibility resource on their networks and their greater ability to manage it effectively and in a more granular manner than the TSO, leads to the emergence of local flexibility markets.
    - In Phase 2b, the information asymmetry is removed by having a single system operator directly responsible for the whole network.

- **Innovation should continue to be encouraged under RIIO-2**. Regulatory incentives under the RIIO-2 regime should continue to encourage DSOs to consider innovative non-asset solutions to network issues. Given that the electrification of heat and transport is driving the increase in demands, it is likely that harnessing their flexibility will be an important part of this innovation.
- **Cost reflective charging will help to mitigate demands for higher network investment**. To the extent that Ofgem's charging reforms will improve the efficiency of locational signals for new distributed energy resources, then these should be supported.
- **The need for strong consumer engagement must not be underestimated**. While attractive commercial offerings from suppliers to encourage more flexible use by consumers will be necessary, this should be supplemented by educating consumers as to how they can benefit from the changes. For example, this will require an explanation as how the new technologies and behaviours can deliver both direct and indirect benefits.

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1. INTRODUCTION

This study has been commissioned by the Energy Systems Catapult (ESC) to 'Assess the Potential Value from Distribution System Operators'. The project has been undertaken by Pöyry Management Consulting (UK) Limited ("Pöyry")[1].

1.1 Evolution of the electricity system

Decarbonisation and technological advances are transforming the electricity sector in regards to both generation and demand. This is leading to increasing numbers of decentralised assets (e.g. generation and storage) connected to the distribution system. At the same time, there are significant changes in the uses of electricity (especially in heating and transport). For example, the pursuit of low carbon options in other aspects of the energy sector, notably electric vehicles and heat pumps, are set to dramatically change the shape of the overall demand on the power system and at the same time introduce new sources of flexibility.

The outcome of these changes is a shift in both:

- the need for flexibility to manage the system; and
- who and what provides that flexibility.

The emerging system is creating new risks and opportunities for distribution networks and to enable them to respond more efficiently to these there is a shift from a Distribution Network Operators (DNOs) to a Distribution System Operators (DSOs) model. This has the potential to impact on all aspects of the DNO's business and its interactions with other stakeholders.

In particular, for the DSOs there will be scope to reassess how actively they are able to utilise the flexibility potential of the decentralised resources connected to their systems and how they coordinate with the Transmission System Operator (TSO) [2] in both procuring and controlling resources that can have benefits to both the local and national system.

1.2 Aims of this study

Our study aims to contribute to the debate on the future market architecture through analysing the extent to which different approaches impact on the potential value of flexibility to the electricity system and the role of DSOs.

To inform this we:

- consider alternative '**Frameworks**' for DSO operation, each of which represents a potential future architecture for DSO and TSO interaction;
- assess the quantitative implications for the system costs across the different Frameworks; and

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1 Unless otherwise attributed the source for all tables, figures and charts is Pöyry Management Consulting.

2 For this report we use the term TSO to mean the role undertaken by either transmission system operator or electricity system operator (ESO).

- qualitatively review the practicality of implementing each framework taking account of the speed of roll-out of new technologies and the need to adapt IT, commercial and regulatory systems.

1.3 Frameworks for DSO operation

Through our Frameworks, we are able to characterise how flexibility can be used by various market participants and the extent to which this leads to benefits for that specific participant, and the market as a whole.

In Section 1.3.1 we set out how the key modelling drivers will vary across our Frameworks. Then in 1.3.2 we present our underlying assumptions for the DSO in the qualitative assessment.

Finally, in Sections 1.4 to 1.8, we summarise each of the 'Frameworks', outlining the main relationships and interactions for the DSO – setting out how we would expect the electricity market to look under these conditions.

1.3.1 Characteristics of the quantitative assessment

Our Frameworks are differentiated across several key dimensions that describe how (a) flexible resources will primarily be used; and; (b) how efficient the locational signals for siting of distributed resource are.

In addition, the 'Frameworks' also show how a decision by one market participant may lead to unintended consequences on others. The risks of unintended consequences is at the core of our analysis and in particular it is important to consider that, as more and more of the cost-effective flexibility will be located on distribution systems, there is a growing risk that using flexibility to meet national constraints may increase the cost of meeting local constraints, and vice versa. Therefore, how the DSO acts, and its interactions with other market participants, is crucial for mitigating these potential inefficiencies.

Table 1 – Modelling assumption to differentiate the Frameworks

	Explanation
Prioritising Peak Demand	Our approach uses a number of Demand Side Response (DSR) sources (e.g. Industrial and Commercial (I&C) DSR, Residential and Commercial Electric Vehicles (EVs)) to help manage peak demand. Through our modelling, we propose three alternative approaches to determine whether the prioritisation is given to local or national peaks. This is a particular issue for these resources, as their application is time limited. When local and national peak demand periods do not coincide, a choice therefore has to be made about their application. These approaches are: 1) meet local constraints (on the distribution system); 2) meet national peaks (on the transmission system); and 3) balanced approach (e.g. resources are split equally between managing local network constraints and meeting national peak demand). The balanced approach will also be impacted by information asymmetry – where information asymmetry exists the balanced approach will not be fully realised. The relative merits of these approaches depends on the extent that avoiding reinforcing the distribution network costs more or less than reducing peak demand nationally.
Embedded generation (Location)	This assumption focusses on the location of embedded assets to help meet constraints on the distribution network. We propose three options: 1) Targeted location: Based on the direct need of the DSO. In this case, charging arrangements alongside clear incentives from the DSO ensure embedded generation is in the right place to help manage operation of the distribution system. 2) Partial: In this case, we assume that embedded resource is not specifically targeted to DSO needs but does result in alleviating some distribution constraints. In this case, charging arrangements provide incentives, but without specific incentives from the DSO the result is sub-optimal. 3) 'Non-targeted': We assume no responsiveness to network signals and allow capacity to be spread evenly across all nodes[3].

[3] In modelling embedded generation locations as non-targeted, this doesn't mean that the generation is spread evenly across the country, but rather that the generation connected at an LV,HV, or EHV level is spread statistically across the many, many nodes associated with those voltages. This is of course a simplification that made the modelling manageable in the face of limited data, but also is not inconsistent with the FES position.

1.3.2 Characteristics of the quantitative assessment

For the qualitative assessment we have assumed a number of important differences between the Frameworks. These assumptions are designed to cover operational consequences of each Framework – for example impacts such as information flows and regulatory requirements. These are set out in Table 2 below.

Table 2 – Qualitative assumptions to differentiate the Frameworks

	Framework				
	1	2	3	4	5
Access to Flexibility	We assume that under each Framework the same level of flexibility is available.				
Access to Flexibility	Flexibility services are first provided to the TSO. The DSO access is secondary.			In Framework 4 and 5 the DSO takes the lead in contracting and activating Flexibility.	
New market participants	We assume similar level of stakeholder engagement across these three Frameworks. We assume more flexibility providers, but this will be constrained slightly due to lower levels of innovation as a result of the prominent TSO role.			In Framework 4 and 5 we assume increased stakeholder engagement due to more opportunities to provide innovative solutions on the distribution network. Framework 5 also introduces a Flexibility coordinator – a new role in the market.	
New information flows	We assume information flows are increased compared to business as usual. Flows are more centralised due to the prominent role of the TSO.			In Framework 4 and 5 we assume more complex information flows due to more disaggregation in the contracting and activation of flexibility.	
Charging arrangements	We assume locational signals will improve charging arrangements in all Frameworks as a consequence of Significant code Review work being undertaken by Ofgem.				
Investment Planning	In all Frameworks we assume the DSO maintains its role in investment planning.				

These Framework assumptions are considered implicitly within the qualitative assessment presented in Section 3.

1.4 Framework 1: Current Position

Framework 1 is our representation of the current system for operation of the electricity networks and acts as the baseline against which the other proposed Frameworks are assessed. This Framework characterises the distribution system as being largely passive, continuing to respond to network constraints primarily through asset-based solutions and not actively engaging with developers of new distributed resources to optimise location. While we recognise that, within the context of the RIIO regime and the ongoing network charging SCR, this is likely to underplay the adoption of innovative techniques by DSOs, it is used primarily as a counterfactual for the other Frameworks.

The passive nature of the DSOs means that the TSO is the core procurer of flexibility within the networks. This means that the TSO will increasingly call upon/activate local flexibility resource to meet national peaks to the extent that this resource is offered into national markets directly or via third party intermediaries (aggregators).

In this Framework the TSO takes the leads with responsibility for procurement and activation of balancing across transmission and distribution. Therefore, it is assumed that, due to the prominent role of the TSO, national balancing is prioritised, with flexibility services (I&C DSR, EVs etc.) used here first, and with any remaining resources used to assist local balancing[4].

A lower level of DSO engagement means that embedded generation is not targeted at specific locations in line with DSO needs (capacity is instead spread across all nodes). While we anticipate that locational signals will improve as a consequence of changes to the charging arrangements, this only leads to a minimal change in the siting decisions. For example, we might expect that increased connection cost in certain congested areas to provide 'signals' for siting.

Our interpretation of the Framework is presented in Table 3.

Table 3 – Current Position modelling assumptions

	Current Position
Prioritising Peak Demand	National peak prioritised
Embedded generation (Location)	Non-targeted

[4] These conflicts are associated with those flexibility services which are limited by energy/time and occur when the needs of the DSO and TSO are in conflict. For example, when DSO has an import constraint and TSO has issues with downward regulation.

1.5 Framework 2: Sharpened Incentives

This Framework implements changes to the network charging regime[5] which may have some impact on the location decisions for distributed resources, however, this is unlikely to be perfect. It is our assumption that this still leads to a sub-optimal solution in regard to the deployment and use of resources between the TSO and DSO.

Other than this change, Framework 2 reflects the market 'architecture' described in Framework 1 (Section 1.4). For example, although the charging arrangements are improved, the distribution system remains largely passive, continuing to respond to network constraints primarily through asset-based solutions and not actively engaging with developers of new distributed resources to optimise location.

National balancing is still prioritised and any remaining flexibility services (I&C DSR, EVs etc.) are used to assist local balancing.

Our interpretation of the Framework is presented in Table 4.

Table 4 – Sharpened incentives modelling assumptions

	Sharpened Incentives	Current Position
Prioritising Peak Demand	National peak prioritised	National peak prioritised
Embedded generation (Location)	Partial	Non-targeted

1.6 Framework 3: TSO Coordinates

In Framework 3, we assume that the TSO leads system optimisation, but works alongside the DSO to ensure a balanced approach towards meeting national and local requirements.

The main challenge in this Framework is to ensure coordination between the DSO and the TSO. The DSO provides information to the TSO that is taken account of in the use of flexibility resource, but it is assumed that there may be imperfections in how that data is reported, used, or assessed. This leads to information asymmetry between the TSO and DSO, resulting in a sub-optimal solution.

We assume a balanced approach for the prioritisation of flexibility services resources which are split equally between meeting the local and national peak. However, the

5 We assume any changes to the transmission / distribution charges and connection costs will be reflective of Ofgem's 'Targeted Charging Review'. This charging review aims to ensure that forward looking charges are designed to ensure stakeholders (generation and demand) receive the correct signals to reduce to costs of operating and using the electricity system.

information asymmetry prevents the ‘balanced’ approach being fully realised. This leads to a sub-optimal solution when compared with Framework 5.

We anticipate that locational signals will improve as a consequence of changes to the charging arrangements, and an increased level of DSO engagement means that embedded generation is not targeted but does result in alleviating some distribution constraints – leading to ‘Partial’ prioritisation of location.

Our interpretation of the Framework is presented in Table 5.

Table 5 – TSO Coordinates modelling assumptions

	TSO Coordinates	Current Position
Prioritising Peak Demand	Balanced	National peak prioritised
Embedded generation (Location)	Partial	Non-targeted

1.7 Framework 4: DSO driven

Framework 4 characterises the DSO as being active. In addition to continuing to respond to network constraints through asset-based solutions, the DSO actively engages with developers of new distributed resources to optimise location and provide smarter / flexible solutions.

DSO has priority access to local resource on its network. It is able to access this through local flexibility platforms and only residual volumes are able to be offered to the TSO for national balancing. This leads to a focus on managing the local peak with the procurement and activation of flexibility targeted for use on the distribution system.

The focus on local balancing means that flexibility services (I&C DSR, EVs etc.) are used by the DSO first, with any remaining resources used to assist national balancing. The DSO also has much stronger incentives to avoid network reinforcement and so achieves much more targeted investment of embedded generation.

Our interpretation of the Framework is presented in Table 6.

Table 6 – DSO driven modelling assumptions

	DSO Driven	Current Position
Prioritising Peak Demand	Local peak prioritised	National peak prioritised
Embedded generation (Location)	Targeted	Non-targeted

1.8 Framework 5: Perfect Information

In our Framework 5, we assume that a single flexibility market is available to optimise the system to balance both the national and local peaks. This leads to optimal deployment and use of resources between the TSO and DSO.

We characterise this Framework as having a single market for all flexibility resources – this market can then be accessed by a single or multiple flexibility providers.

Under this Framework, we assume a complete set of efficient market signals that enable resource to be allocated where it provides most value. This may arise from a single overall system operator that manages the local and national systems or a set of perfectly integrated local and national flexibility platforms that work seamlessly to deliver a solution. The flexibility itself may be provided by one or many actors.

The core requirement is that that all information (about flexibility provision and system optimisation requirements) is freely available to whoever is given the role of system optimisation. This Framework seeks to address the conflicts that may arise under 'TSO Coordinates' (e.g. in terms of prioritising resources).

Information provided by the DSO leads to a balanced approach to the prioritisation of peak demand and ensures that embedded generation is located in optimal areas to assist the DSO with managing constraints. In this case the combination of perfect information and a 'balanced approach' to prioritising peak demand leads to a enhance solution when compared to Framework 3.

Our interpretation of the Framework is presented in Table 7.

Table 7 – 'Perfect Information' modelling assumptions

	Perfect Information	Current Position
Prioritising Peak Demand	Balanced	National peak prioritised
Embedded generation (Location)	Targeted	Non-targeted

1.9 Mapping with the ENA Worlds

A range of market 'architectures' have already been established through the ENA Open Networks project[6]. This project has determined five 'Worlds' which have been designed to reflect the different relationships and process between the DSO and other market stakeholders. These Worlds are set out below:

- **World A – DSO coordinates**: DSO takes a central role for all distribution connected parties acting as the neutral market facilitator.
- **World B – Joint procurement**: DSOs and ESO work together to efficiently manage networks through co-ordinated procurement.
- **World C – Price driven flexibility**: Electricity network access and forward looking charges have improved access arrangements.
- **World D – ESO coordinates**: TSO takes a central role in the procurement and dispatch of flexibility services.
- **World E – Flexibility coordinators**: National (or regional) third party acts as the neutral market facilitator.

Our Frameworks emerged from an interpretation of the initial ENA Worlds. The publication of the detailed assessment[7] during the course of this project has highlighted some differences in interpretation or representation. To avoid both confusion, and inaccurate comparisons between our analysis and the impact assessment undertaken by the ENA we present a high level mapping below.

Our 'Frameworks' and the 'ENA Worlds' on from which they emerged, are summarised in Table 8. Then in Table 9 we outline key differences between our Frameworks and the ENA Worlds.

Table 8 – Pöyry Frameworks

ENA Worlds	World D	World C	World B	World A	World E
Pöyry Frameworks	Current Position	Sharpened incentives	TSO coordinates	DSO driven	Perfect Information

[6] The Open Networks project is looking to address the challenges that will be faced as a result of the changes in the roles and responsibilities of Distribution Network Operators

[7] The ENA impact assessment and associated consultation are location here: http://www.energynetworks.org/electricity/futures/open-networks-project/future-worlds/future-worlds-impact-assessment.html

Table 9 – Summary of differences between our Frameworks and the ENA Worlds

Pöyry Framework	Difference to closest ENA World
Current Position	The ENA assumes that in the short term the DSO is able to manage its network efficiently based on asset solutions, but in the long term TSO coordinate all flexibility services to LV. In our Framework we assume relationships continue as now, so the division of roles on the distribution and transmission network remain the same.
Sharpened Incentives	The ENA assumes price signals work optimally following the changes made as a result of the Ofgem SCR. We assume the charging arrangements are an improvement from Current Position, but still lead to a sub-optimal outcome.
TSO Coordinates	The ENA assumes the DSO needs are prioritised, with residual flexibility offered to the TSO. In our Framework, the TSO needs are prioritised with residual flexibility offered to the DSO.
DSO Driven	The ENA assessment assumes the DSO does not have balancing responsibility. Our Framework assume a key role for the DSO in balancing and procuring / activating flexibility – with left over resources passed to the TSO.
Perfect Information	We assume a single market for flexibility resources which can be accessed (with perfect information) by a single coordinator.

2. QUANTITATIVE ASSESSMENT

In this chapter we describe the methodology used to assess the Frameworks, alongside the results of the assessment.

2.1 Introduction

The starting point for this analysis is the Two Degrees scenario from National Grid's 2018 Future Energy Scenarios ("FES"). This represents the FES scenario with the highest level and fastest speed of decarbonisation in the GB system; the decarbonisation target is met using larger and more centralised technologies. This scenario was chosen to focus the modelling around a world in which these targets are successfully met. By way of contrast, it would have been possible to examine the Community Renewables scenario. This would have interesting implications for DSOs, with more resources connected to the lower voltage levels of the distribution network. The desire, though, to keep the analysis simple led to the one FES scenario approach. Nevertheless, the conclusions reached via the Two Degrees scenario would be extendable were the analysis based on another FES scenario.

Within the context of the Two Degrees scenario, the modelling focussed on how the distribution system would function. This involved mapping the system described in this scenario into a high-level, characteristic distribution network model, and to quantify the impact of the different Frameworks, as described in Section 2.

Table 10, sets out those elements located within the distribution network and included within the model. In particular, the demand, embedded capacity and capability of the distribution network are given the most detailed treatment.

Table 10 – Overview of the distribution network modelling approach

Aspect	Input	Methdology
1. Demand	Demand (TWh)	Taken from FES, split according to sector (Domestic, Commerical etc) and type (Base, EVs, HPs etc)
	Demand shape (GW)	Derived from FES, focussed on winter peak and summer minimum
	Demand location	Mapped to Urban, Sub-urban and Rural network geographies
2. Network representation	Network geography	Transmission network modelled as one entity, distribution network split according to location and voltage level
	Voltage levels	EHV, HV and LV levels representative of 66-132kV, 11-33kV and 0.4kV respectively
	Network nodes	Statistical approach taken to modelling the network represented activity at notional transformers
3. Demand flexibility	Demand flexibility	Taken from FES, to have a common level of flexibility in all pathways
	Use of demand flexibility	Application varied according to the pathway
4. Generation capacity	Total capacity	Taken from FES
	Embedded capacity location	Geography and voltage level of capacity extrapolated from FES
	Embedded capacity benefit	Extent to which capacity can help reduce network reinforcement is varied by pathway
	Embedded generation	Availability of each generator type in different modelled periods based on appropriate availability factors
5. Network investment	Overall network capability	Determined based on the coincidence factors of demand sectors and types
	Network reinforcement	Either End of life assumption or exceeded security standard assumptions trigger investment
6. Generation invesment	Generation energy costs	Commodity prices from FES combined with Poyry views on technology generation costs
	Generation capex/opex	Base capacities taken from FES and varied according to peak demand plus security standard assumption
	Energy balancing	Energy imbalance determined based on statistical analysis of historical balancing needs

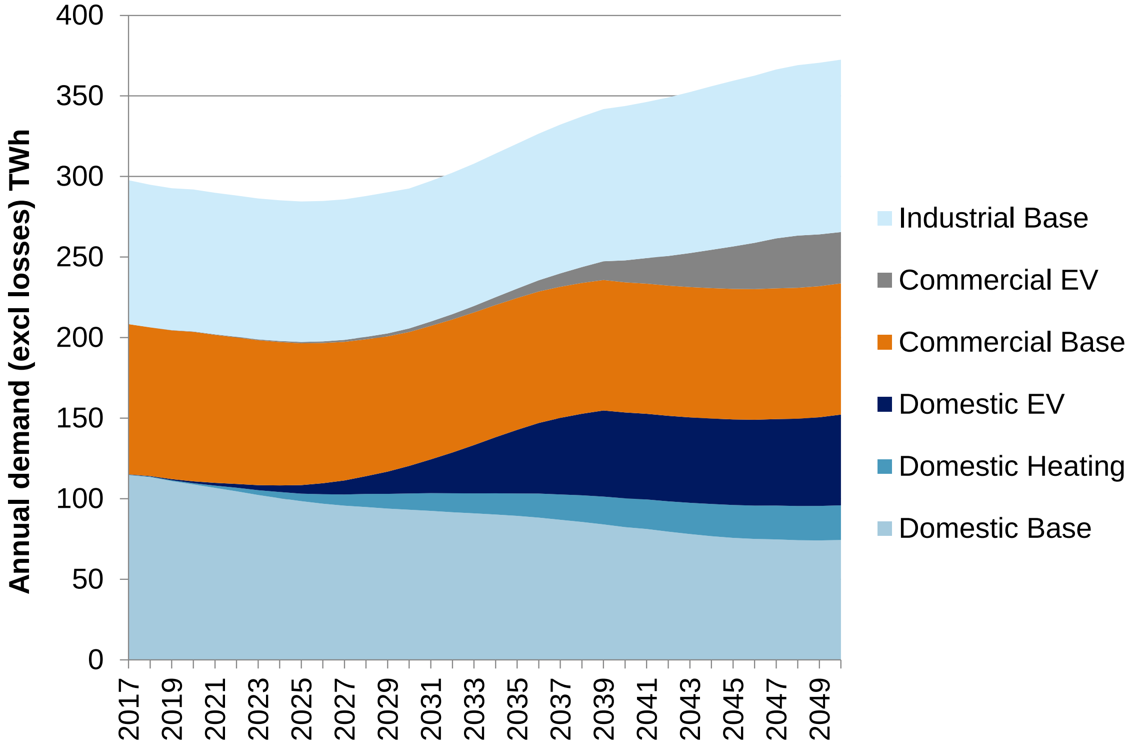
2.2 Assessment approach

The following sections go into more detail concerning the high level design of the model described above, and how the analysis of the Frameworks was performed.

2.2.1 Demand

The FES Two Degrees scenario provides information about the evolution of electricity consumption out to 2050. These annual numbers for the consumption of different sectors are shown in Figure 1. This shows the reduction in domestic demand as a result of energy efficiency is more than offset by the increase in additional electrification of heat and transport. In the industrial and commercial sectors base demand remains relatively constant across the period, with growth coming from uptake of commercial EV demand from 2030.

Figure 1 – Annual demand by sector, FES Two Degrees scenario 2018 (TWh)



The analysis for the distribution network was focussed around four critical periods in the year:

- the local peak within the distribution network;
- the national peak;
- the summer noon peak solar output; and
- the summer overnight minimum demand period.

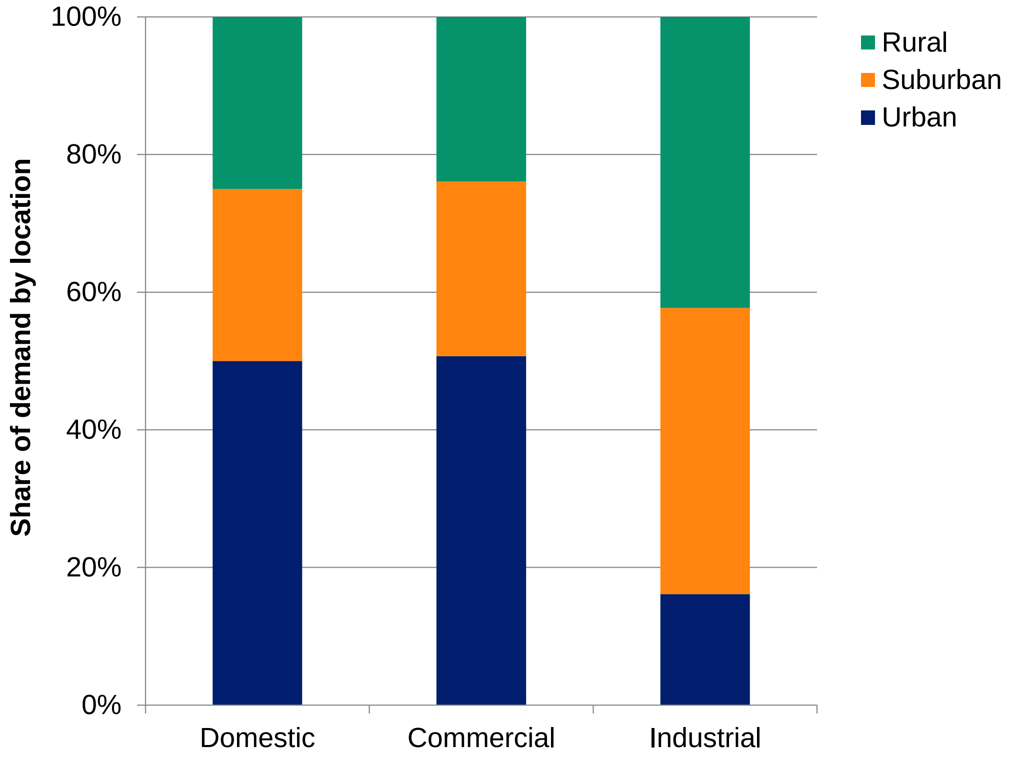
These were chosen so that the dimensioning periods of the system would be considered. Taking the annual demand values for each network geography and voltage level, profiles were applied in order to model the hourly demand levels at the chosen key times

2.2.2 Network representation

This demand was mapped onto the characteristic network, according to the locations of the different demand sectors. This gave rise to the demand on the different network geographies (Urban, Sub-urban and Rural) and the voltage level connection of the different demand sectors (LV, HV, EHV).

For each of the different voltage levels, the network was modelled with a characteristic nodal size. The network was conceived of a series of nodes, supported by substations/transformers of a notional size. The transformers represented the point of stepping down the voltage level from the transmission network to EHV, EHV to HV and HV to LV levels. This allowed a statistical approach to the network to be taken when considering the location of generation capacity and the needs to replace parts of the network.

Figure 2 – Split of demand by location for the different sectors



The model was focussed around MW and MWh, and did not directly consider other aspects of managing the distribution network such as voltage support or reactive power.

2.2.3 Demand flexibility

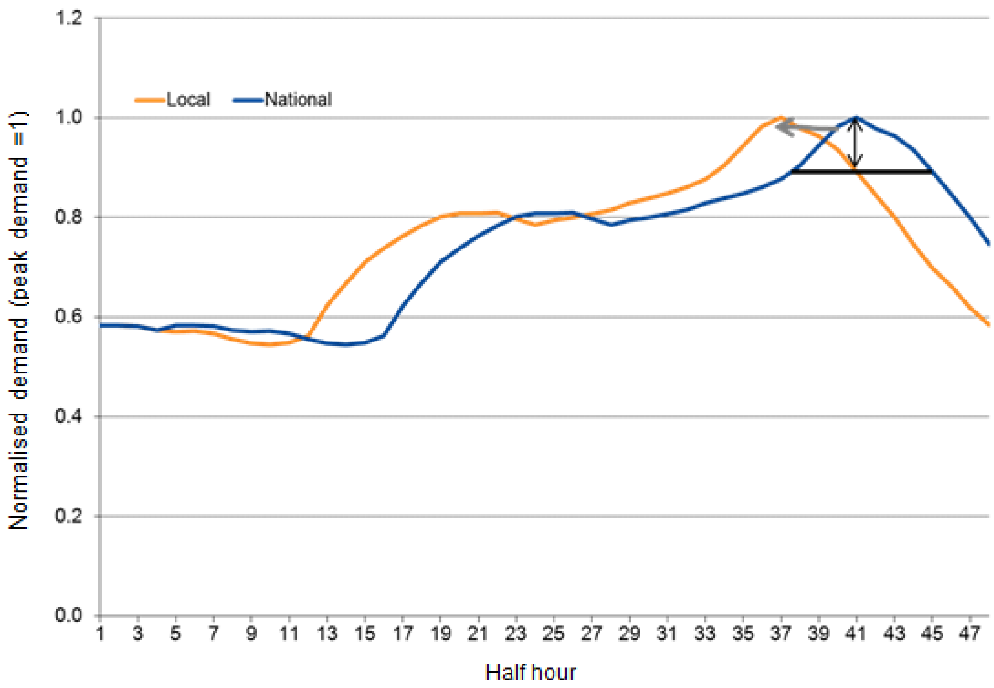
Having derived a raw demand value for these four critical periods of the year, the model also accounted for the flexible demand assumptions, as provided in the FES scenarios. These demand flexibility assumptions included the impact of:

- 'Time of Use' (ToU) tariffs on Domestic EV charging;
- ToU tariffs on Commercial EV charging;
- 'Vehicle-to-Grid' services from Commercial EVs; and
- 'Industrial and Commercial' turn-down (DSR).

This is the first point at which the model introduces assumptions that were varied according to the modelled Framework. The total flexibility resource is constant in the different Frameworks, but the use of it varies. Whilst the overall level is consistent with the demand flexibility assumed in the FES Two Degrees scenario, the different Frameworks included different applications of this flexibility and therefore represented a range of outcomes that deviated from the demand levels present in the official Two Degrees FES scenario. In the Current Position framework, the peak and minimum demand levels replicated the FES scenario, and other frameworks deviated from this, depending on other input assumptions in the model.

Each of the different elements of the modelled demand flexibility has a time dependent element, and therefore the response provided by any of these providers will not necessarily have the same final impact if the DSO or ESO has primary use of the service. In the case of time of use tariffs, shifting demand away from the national peak can create a new problem for the DSO, because the DSO network peak does not coincide with the national peak. This is represented schematically in Figure 3.

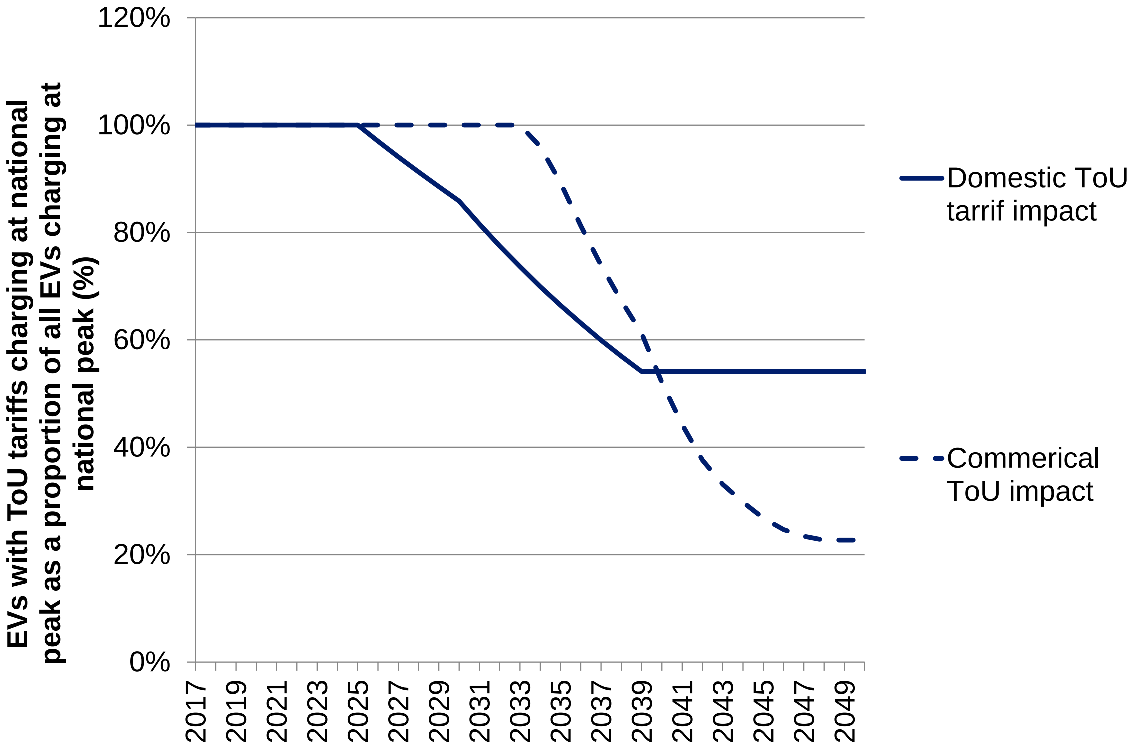
Figure 3 – Modifying demand at national level to avoid maximum peak demand and creating a problem at the DSO level (schematic)



The key observation here is that different consumer groups in different parts of the network will have a range of hourly consumption patterns. The extent to which the local peak managed by the DSO is aligned with the national peak demand will depend on a large number of factors, and the precise make-up of the local consumers. The model represented this through the use of coincidence factors for the different types of demand.

The overall impact of 'ToU tariffs' on the national peak demand is shown for Framework 'DSO driven' in Figure 4. This is expressed as the proportion of the demand from EV charging that remains in the peak period after the introduction of ToU tariffs, when compared with the amount that would have occurred without that incentive to reduce consumption at that time. This assumption is varied in the different Frameworks depending on whether the local or national peak was the priority for the DSO, and the amount of demand shifted depended on the normalised difference in magnitude between local and national peaks.

Figure 4 – Impact of time of use tariffs on EV charging at the time of national peak demand, Framework 1



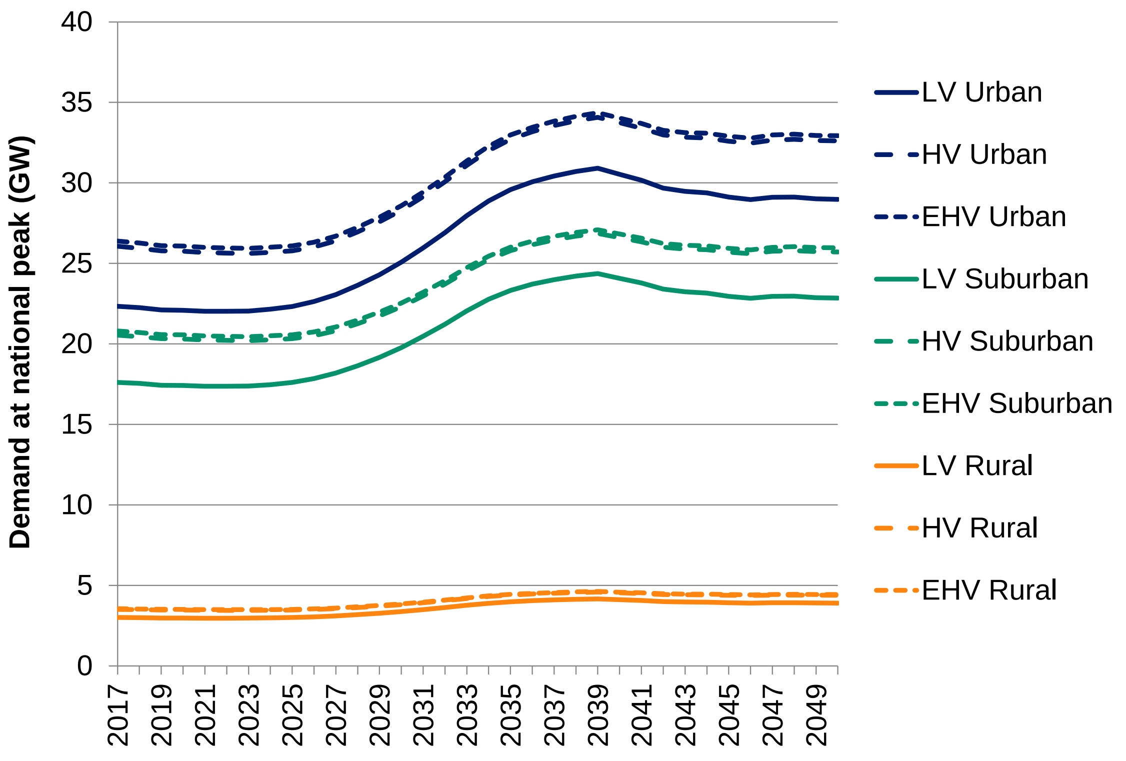
Similarly, in the case of 'Vehicle to Grid' discharge and DSR, these services are assumed to be time limited in use, and therefore utilising them at the time of the national peak could prevent them being available at the time of the local peak. The converse could also apply, whenever the time of local and national peak demand does not coincide.

In the case of each of these services, the different Frameworks included different assumptions on the different application of the flexible demand services, with different approaches to whether the demand reduction is greatest at the time of national or local peak demand. The specific approach for each of the frameworks is set out in sections 1.4 to 1.8.

Having modelled the final net demand from each of the demand sectors and locations, the model aggregates these to give the final demand supported by each of the voltage levels. LV located demand is supported by the HV, and the HV level by the EHV network respectively. For the different modelled periods, this then defines the demand at time of the winter system peak, the summer peak solar output, the summer overnight demand minimum.

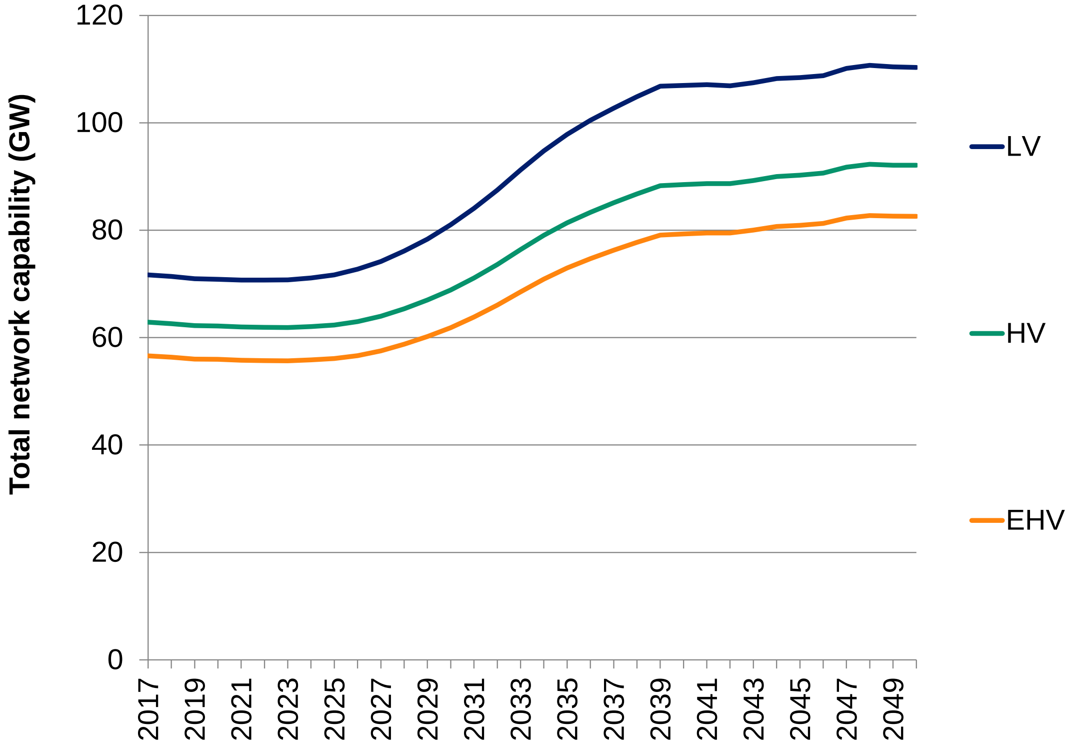
Figure 5 shows these results for Framework 1. These figures are for the demand net of the use of DSR; however, the impact of embedded generation is not included and therefore the final demand is eventually lower. As expected, the highest demand is found in the 'Urban' network, where most consumers are located. The EHV peak demand is higher than HV, which in turn is higher than the LV, representing that the power is drawn down the voltage levels. As the Two Degrees FES scenario features a high level of electrification in the 2030s, peak demand increases. Beyond 2040, the impact of EV demand side flexibility begins to dominate and the national peak demand value does not increase any more.

Figure 5 – Net demand at time of national peak demand, by distribution network location and voltage level, in Framework 1



The overall network capability required to support all local peak demands was also modelled. We modelled that the current network capability is sufficient for the demand levels of today. Figure 6 shows the required network capability for the distribution network in Framework A.

Figure 6 – Overall network capability for the distribution networks in Framework 1



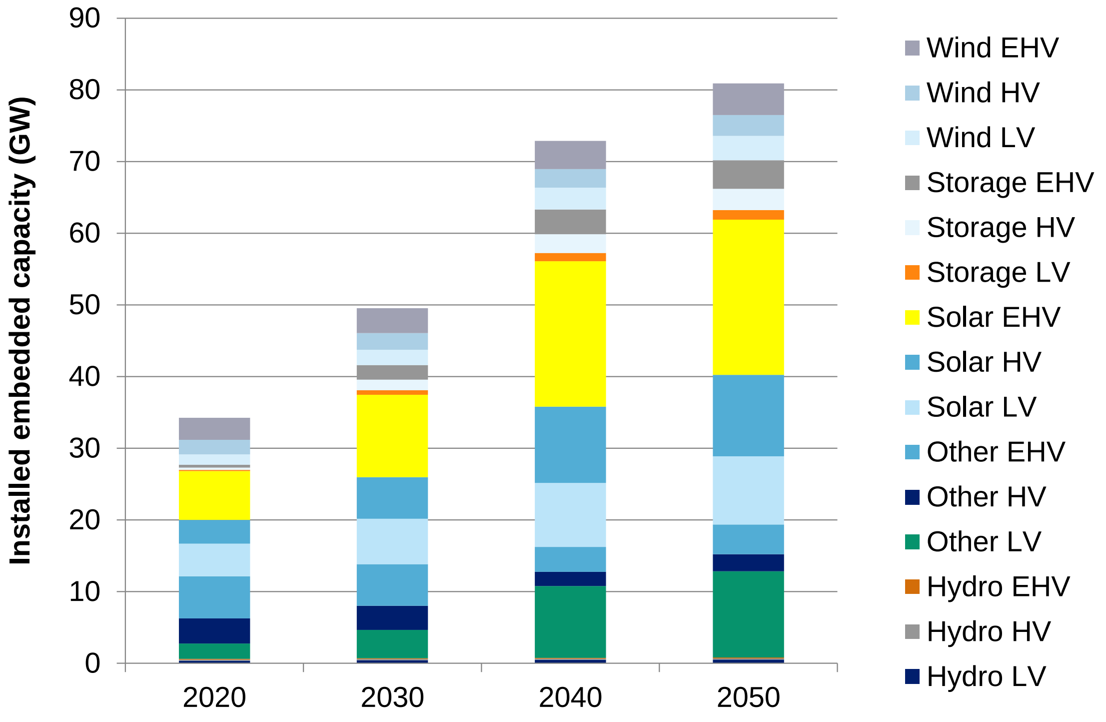
2.2.4 Generation capacity

Total generation capacities and annual generation volumes were taken from the FES scenario assumptions. Together with typical generation cost assumptions and efficiencies, this allowed the model to calculate the basic annual generation costs per year.

The second aspect of the generation capacity was to consider the behaviour of the generators in the four critical modelled periods of the year. Having constructed the demand in the network, the model then applied the impact of embedded generation to the demand at each of the locations and voltage levels. This split is shown in Figure 7.

The embedded installed capacity was assigned de-rating factors to model their typical output in the periods considered by the model. The final output from each generation source was then added into the (demand only) power flows through the distribution network, in order to find the final net flow flows through the distribution network. This also led to a final value for the demand placed on the transmission system for each of the modelled periods.

Figure 7 – Installed capacity of embedded generation by location and connection voltage level (GW)



Note: the category of "Other" contains all thermal generators within the distribution network.

The nodes of the distribution network, having been modelled with a characteristic size, had generation capacity spread across them differently according to the different Frameworks. Each of the different embedded generators have also been modelled with a characteristic size. A statistical approach was then taken to which network nodes benefitted from the embedded generators with firm capacity available at the peak periods, and how this influenced the power flows down the distribution network voltage levels from the transmission network (or indeed up the voltage levels when there was excess generation above the amount of demand).

The location of the generators, in regard to the ability of the capacity to defer network reinforcement, is a variable that is changed depending on the Framework.

2.2.5 Network investment

Section 2.2.3 above sets out how the model arrives at the network capability for each part of the network. This entire distribution network is modelled as the demand supported by notional transformers of a certain size. Table 11 contains the assumptions used for the size of the notional transformers, the voltage levels they represent, and the security standard assumed for each voltage level.

Based on these assumptions, the model had to upgrade the transformers whenever the security standard was exceeded. These upgrades consisted of adding another transformer of the same size, in addition to reinforcing the network below that point, such as the cabling.

Table 11 – Assumptions used for modelling of voltage levels' substations

Voltage level	Single transformer rating	Transformers present per substation node	Security standard
EHV (66 and 132kV)	100MW	2	N-1 condition
HV (11 and 33kV)	15MW	2	N-1 condition
LV (0.4kV)	1MW	1	No demand allowed above rated capacity

If the transformers were not requiring an upgrade due to rising demand levels, then the model would also consider when the transformers reached the end of their life and needed a like for like replacement. This was done such that no transformer was replaced at the end of its life only to require an upgrade in a subsequent future modelled year, leading to unnecessary costs. The model treated the system with simple perfect foresight, and therefore no transformer was both reinforced and replaced across the modelled timeframe. In reality, some reinforcement costs would be incurred earlier, namely, when the asset manager recognises that it makes sense to upgrade this aging asset at a given point in time. Effectively, in this model, the asset manager of a given transformer would recognise that an upgrade would soon be needed and so delays replacing the aging asset for a few years.

The model employed a normal distribution to current demand levels on each transformer, with the assumptions on mean and standard deviation peak demand levels chosen so that no transformers are currently breaching their security standard. These numbers were calibrated based on the assumption that the current network capability is sufficient to support present demand levels.

Figure 8 – Reinforcement and end of life replacement of transformers on the LV network in Framework 1

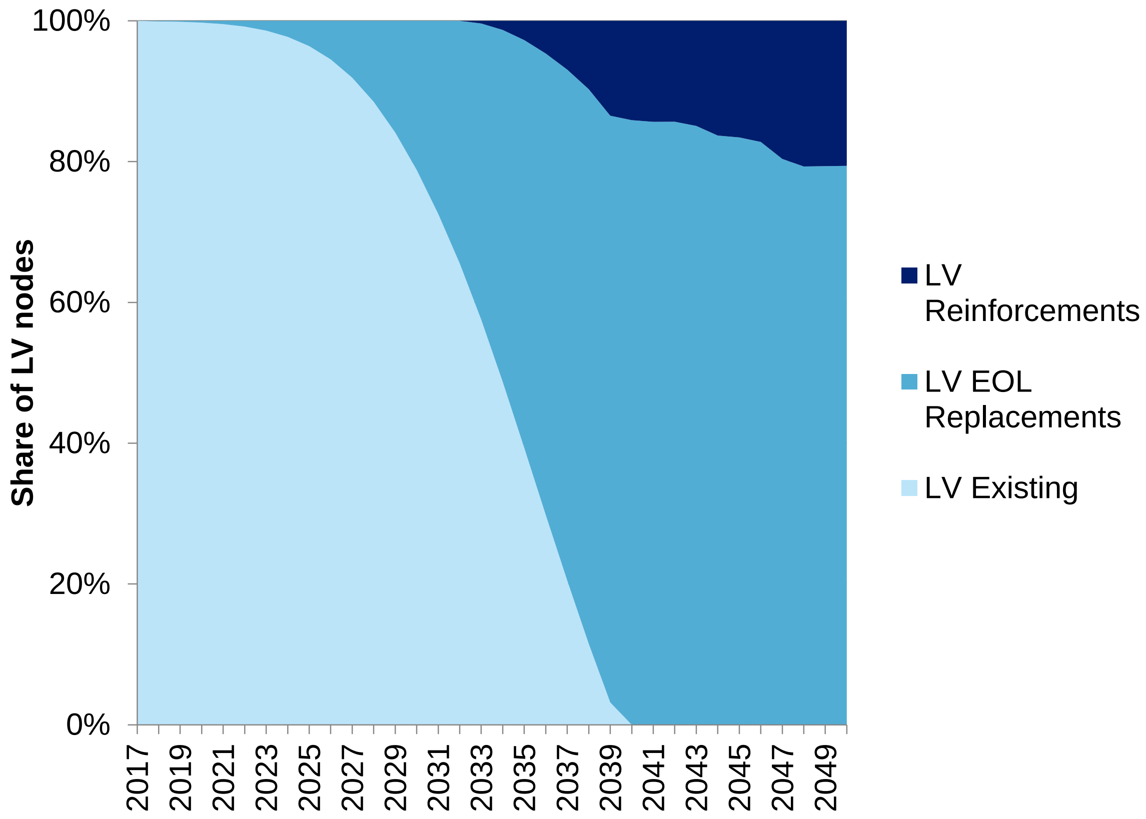


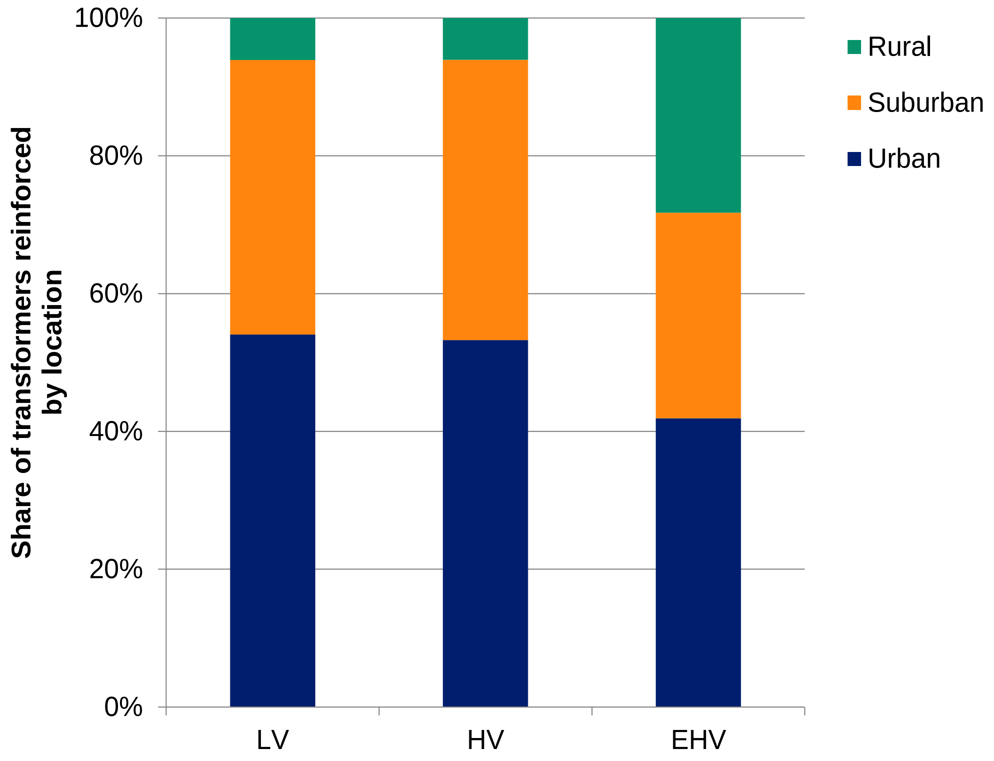
Figure 8 shows a summary of the investment in LV transformers in Framework 1; initially, transformers are primarily replaced due to end of life of the assets[8], but beyond 2030 the growing electrification on the system means that a significant share of the nodes needed an upgraded transformer to deal with the increased peak demand levels. This is despite the use of DSR and embedded capacity to mitigate the rising demand. The use of these services and generators was insufficient due to the DSR being used for a variety of different purposes, thus limiting its ability to further reduce local peak demand, and the generators were not necessarily located on the nodes that had the highest levels of peak demand.

Figure 9 (below) also shows the locations of the transformers reinforced in Framework 1. The LV transformers that required an upgrade by 2050 in Figure 8 were predominantly in the Urban and Sub-urban locations. This result flows from the inputs of Figure 2, whereby the majority of Domestic and Commercial consumers are in these locations and also connected to the LV network. It is these consumers who are switching to electrified transport and heating in the FES scenario, driving the need for expansion of the LV network.

8 For modelling purposes we assume an average asset life of 50 years.

The difference seen for the Rural transformers is driven by the different consumer make-up of the Rural networks, and additionally that there is also a large amount of solar PV capacity that has to be accommodated into the Rural network at the higher voltage levels.

Figure 9 – Proportion of transformers requiring reinforcement upgrades in Framework 1, by location and voltage level, by 2050



The costs associated with the reinforcement and replacement of network assets are set out in Figure 10. These are based on a previous study we completed alongside the University of Bath.

Figure 10 – Network reinforcement costs (£k / MW)

£k/MW	Urban	Suburban	Rural
LV	291	202	72
HV	166	122	74
EHV	120	99	91
Transmission	500 £k / MW		

Source: University of Bath and Pöyry analysis

In addition to the reinforcement needed due to rising demand levels, the same logic was employed to manage the embedded generation capacity. This was found to be especially relevant for the solar capacity built in the rural networks. The model had the choice either to curtail this solar output or to reinforce the network in order to allow the power to be accommodated and fed into the higher voltage levels or even the transmission network.

The final aspect of the modelled network investment was that the transmission network was reinforced in order to accommodate the rising peak demand values.

2.2.6 Generation investment

Having established the modelling of the distribution network, the final aspect of the model was to calculate the impact of the use of flexibility within the distribution on the rest of the system. In addition to reinforcing the transmission network to accommodate the growth in demand, the model also calculates the needs for extra generation capacity connected to the transmission network.

There were two aspects to this part of the modelling. The first was focussed around the peak and the case that peak demand was rising to such an extent that there was need for additional peaking capacity on the transmission network. In such an eventuality, the model calculated the extra gas turbine capacity required in order to maintain a 3 hour loss of load expectation (as per the calculation of the demand for capacity in the Capacity Market).

Secondly, in the event that embedded renewable generation was curtailed due to thermal capacity constraints within the distribution network, the model would calculate the additional renewable capacity required to ensure that the emissions reduction targets would still be met. The approach was to calculate the total TWh of curtailed renewable generation within the distribution network and calculate the next cheapest means of meeting these generation volumes and the emissions obligation. The model calculated, therefore, the additional transmission connected onshore wind capacity required in order to ensure an equivalent volume of low carbon generation was replaced. The model also assumed that with solar curtailment in the summer, this generation volume would be met by efficient CCGT operation (as the cheapest available plant able to generate in place of the curtailed solar), and that the increased onshore wind capacity would reduce output from less efficient gas plant in the winter. As such, there was also a generation cost impact to curtailment of renewables.

2.2.7 Energy balancing costs

The model took a relatively simple approach to the cost of balancing. The costs of redispatching in order to manage transmissions constraints were assumed to be constant in all Frameworks. However, it was assumed that the network would have to be reinforced in order to accommodate the increasing wind capacity. With regards to the cost of energy imbalances, regression analysis showed that there is a strong correlation between historical balancing costs compared with the total installed intermittent renewables capacity, peak demand and commodity prices. This regression formula was applied to the final modelled transmission system national peak demand and final renewable capacities, together with the FES commodity prices, in order to calculate the cost of balancing the system. In addition, the model assumed that with the increased supply of flexible generation, there would be a gradual reduction in overall costs over time. This cost reduction was represented in the form of a negative exponential function.

2.3 Assessment results

The results of the quantitative assessment are discussed in this section by first comparing the total system costs across Frameworks, and secondly by looking at the evolution over time of each cost component for each Framework, compared to the ‘Current Position’.

Figure 11 shows the split of costs by 2050 across Frameworks between the different cost inputs. The chart shows that the highest cost component across the Frameworks is ‘Generation CAPEX and OPEX’, which accounts for almost 50% of the system cumulative costs. The next biggest element (approximately 30%) originate from energy costs (including generation and balancing) followed by the **distribution networks costs,** which account for almost a quarter of the costs. The remainder is made up of the transmission networks costs[9].

Our study is focussed on the savings from the ‘**distribution network costs**’, however it is clear from Figure 11 that the targeting other parts of the energy system (e.g. generation costs) has the potential to deliver much greater savings for the economy as a whole.

Figure 12 presents the cumulative discounted costs by 2050 of each Framework relative to the ‘Current Position’. The ‘Current Position’ Framework features the highest cumulative total system cost at £563bn, over £7.2bn more expensive than the ‘Perfect Information’ Framework.

Our assessment did not include a detailed analysis of the costs of implementing these frameworks. However, we believe the costs identified by the ENA Impact Assessment[10]; indicate that significant benefits are still achievable – even after accounting for the differences in the architecture between the ENA Worlds and our Frameworks.

9 Distribution network costs are much higher than transmission system costs despite similar expansion costs. This is because these scenarios require much greater reinforcement at local levels to facilitate the increased demand and flexibility resources.

10 The ENA impact assessments states the costs of the Future Worlds will be between approximately £500 million and £700 million in 2050, depending on the particular World and assuming reformed charging arrangements in line with Ofgem’s current review are in place.

Figure 11 – 2050 total cumulative discounted costs across Frameworks

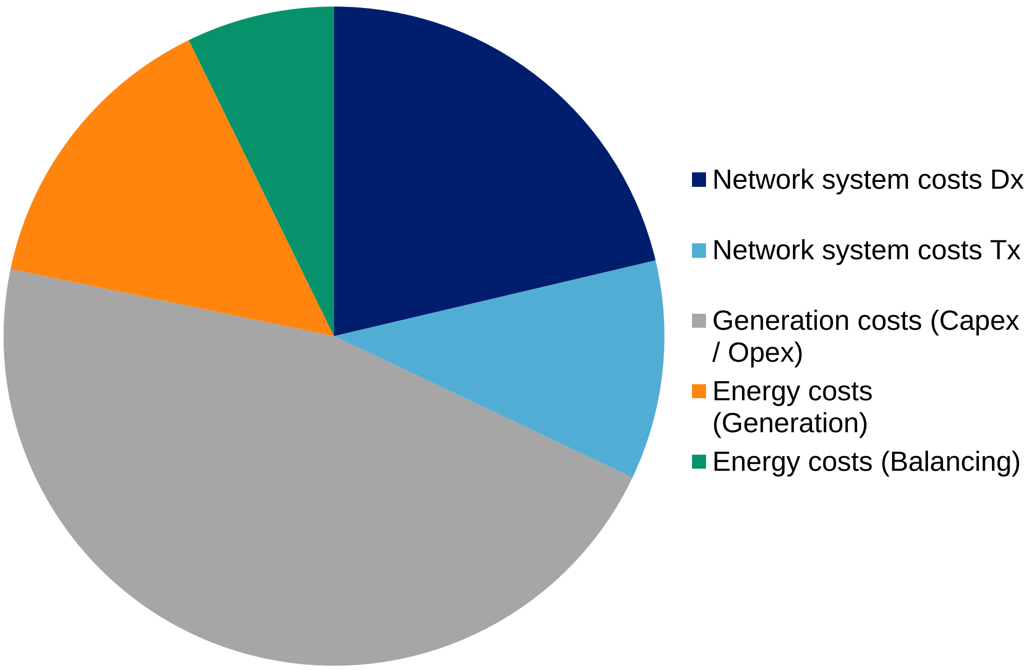
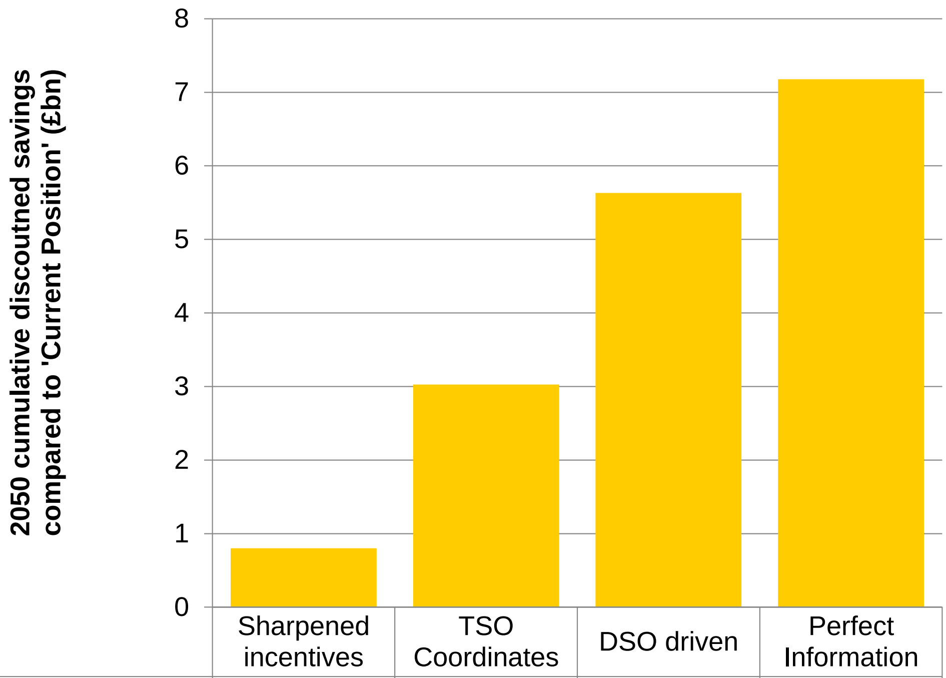


Figure 12 – 2050 total cumulative discounted cost savings, compared to the 'Current Position' Framework



	Sharpened incentives	TSO Coordinates	DSO driven	Perfect Information
Total savings (%)	0.14%	0.54%	1.01%	1.29%
Total savings (£bn)	0.8	3.0	5.6	7.2

2.3.1 Net cumulative savings

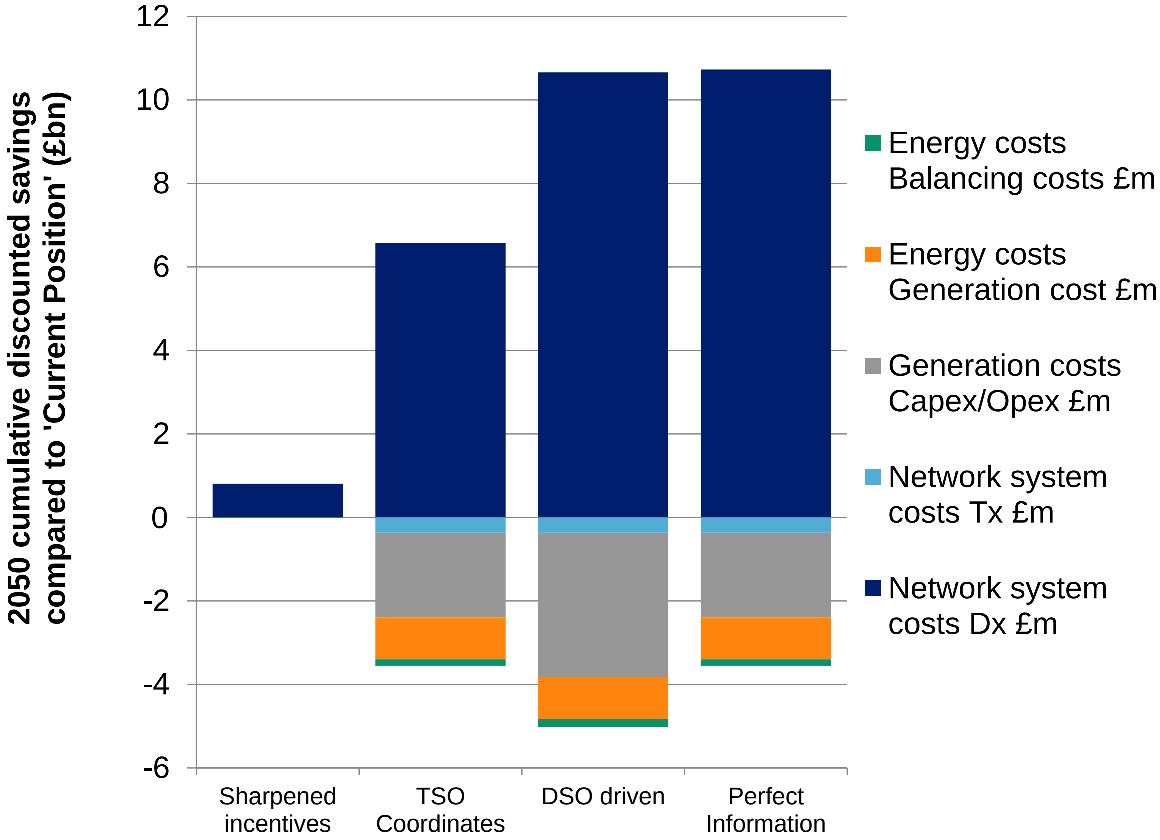
Figure 13 presents the cumulative discounted savings by 2050 for each Framework, relative to the 'Current Position' for each of the five cost components that contribute to the total system costs. Savings on distribution network costs are the largest component across all Frameworks.

Those savings are attributable to a lower local peak and the ability of electric vehicles to respond to price signals (e.g. via time of use (ToU) tariffs) to reduce this peak. This is noticeable in both the 'DSO driven' and 'Perfect Information' Frameworks, as the commercial and residential EVs are assumed to behave in a way such that local peak is prioritised over the national one as described in Sections 1.7 and 1.8.

Similarly, V2G from commercial vehicles and industrial DSR have the effect of alleviating local constraints more decisively in 'DSO driven' and 'Perfect Information', when compared to the 'Current Position'. In addition, the difference between the savings in the 'DSO driven' and 'Perfect information' Frameworks lies in the extra generation CAPEX/OPEX incurred in the 'DSO driven' Framework, due to a slightly worse information exchange. This leads to lower availability of distributed demand side management at the national peak and therefore increases the need of additional spending in peaking plants to meet the national peak,

'TSO Coordinates' has relatively lower savings on the distribution network costs compared to the savings in 'DSO driven' and 'Perfect Information', as we assumed that a 'balanced' approach is taken. The flexibility deriving from ToU tariffs, V2G and DSR technologies is used to partially alleviate both the national and local peak. The TSO makes use of the available flexibility to help with national issues, and only subsequently to alleviate distribution network constraints, since it lacks the necessary information. This approach means benefits delivered are lower.

Figure 13 – 2050 cumulative discounted cost savings for each cost component, compared to the 'Current Position' Framework



On the other hand, energy, generation and transmission network costs are higher across the 'TSO Coordinates', 'DSO driven' and 'Perfect Information' Frameworks, when compared to the 'Current Position'.

Generation CAPEX/OPEX are the largest source of the higher costs. These higher costs are driven by the need for more generation capacity at the national peak, given the prioritisation of local peak for V2G and DSR, as well as by the additional spending necessary to build and operate transmission connected RES – assumed to be onshore wind – to meet the RES generation target, given the higher level of curtailment in the Frameworks. The resulting additional wind onshore capacity is around 1GW in 2050 in the Frameworks[11]. In addition to the differences above, the 'DSO driven' Framework also features higher generation costs compared to the other two, as the prioritisation of local balancing means that flexibility services are almost completely unavailable for the national peak, leading to a higher need for additional peaking plants.

Energy costs (balancing and energy) are consistently higher relative to the 'Current Position' across the three Frameworks and account for around £1bn of the extra costs. As described in Section 2.2.7, this is due to accepting constraints on the location and

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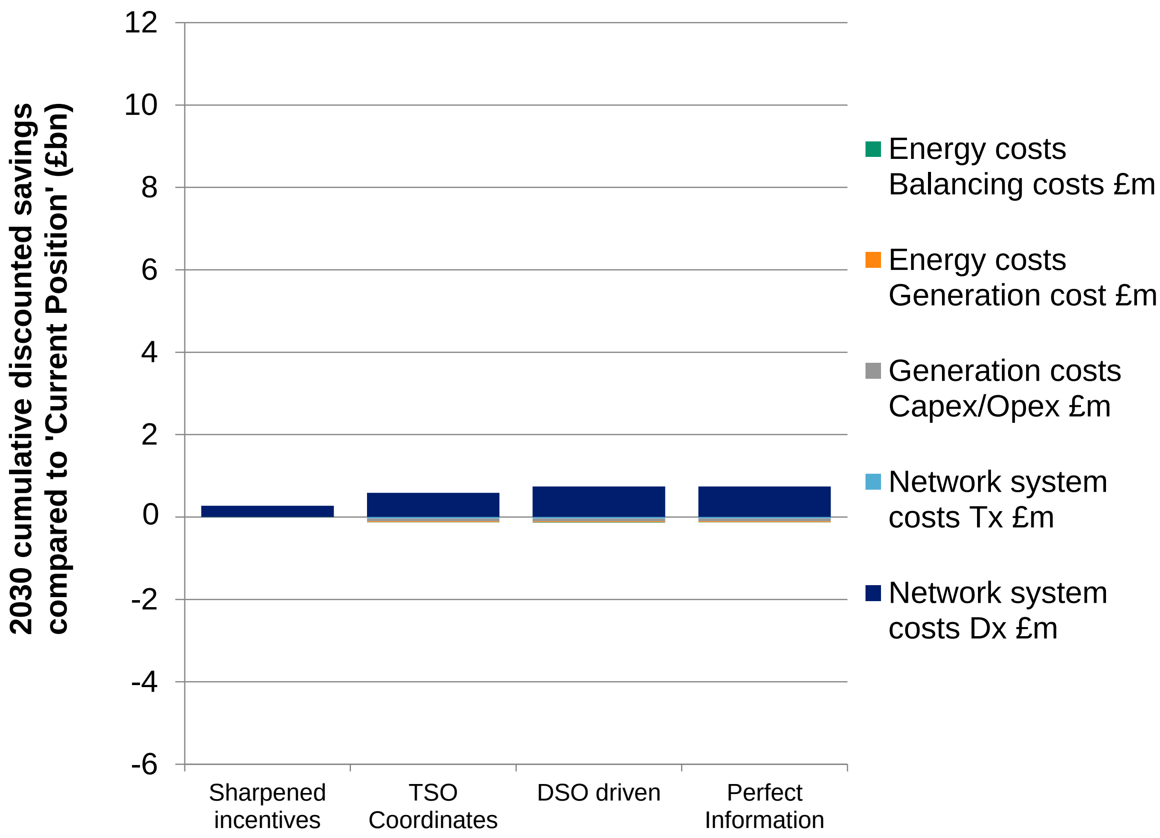
11 The FES Two-Degree Scenario assumes approximately 40GW of solar generation connected at the distribution level. If this capacity was to be connected at transmission level then the need for curtailment of Solar PV would be reduced.

running of embedded generation in return for lower levels of reinforcement in the distribution network..

Finally, the 'Sharpened Incentives' Framework only differs from the 'Current Position' by £800m (cumulative savings) by 2050, largely due to lower distribution costs, attributable to higher availability of DSR for the local peak.

Figure 14 – 2030 cumulative discounted cost savings for each cost component, compared to the 'Current Position' Framework

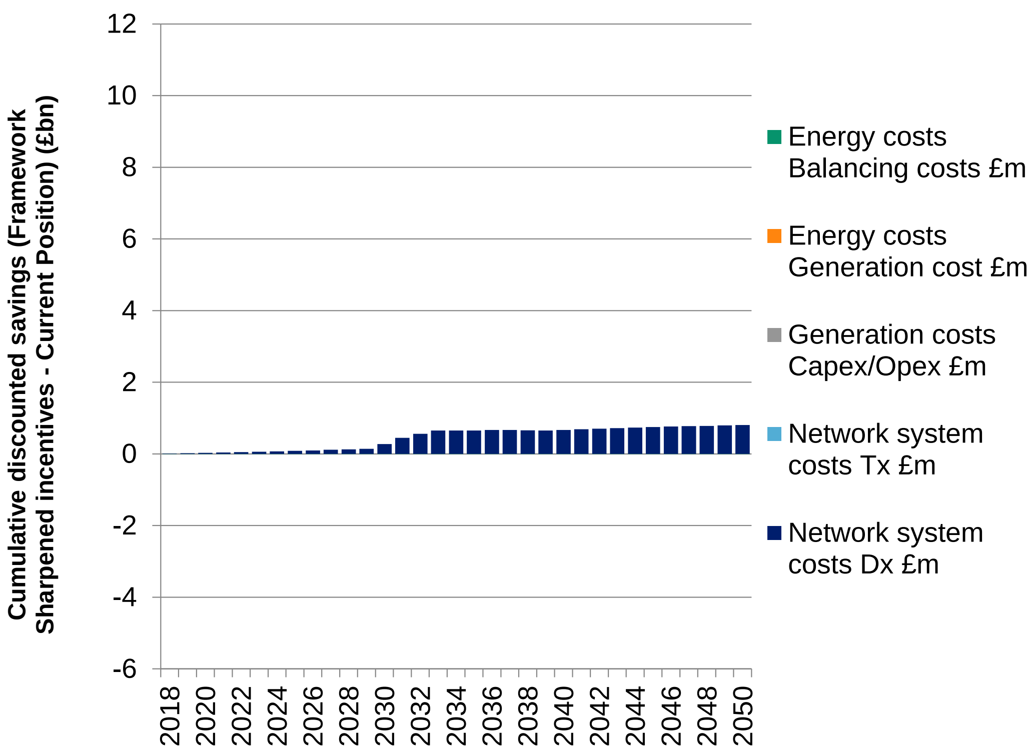


2.3.2 *Assessment over time*

Figure 14 shows that only a small proportion of the 2050 total system savings are realised by 2030. The 'Sharpened incentives' Framework features the highest level of cumulative 2030 saving – 34% – as a proportion of the cumulative 2050 savings (£270m of £800m), whereas in the 'Perfect information' Framework only 9% of cumulative 2050 savings (£610m of the £7.2bn) are realised by 2030. As evidenced in Figure 15 to Figure 18 , most of the savings are realised after 2030 across all Frameworks and driven by the lower distribution network costs. Post 2030 flexibility services start to have a noticeable impact and decreasing the need for distribution network reinforcements after 2030. This is a result of both an increase in the provision of flexible resources and together with an increased need for this flexibility to help manage the system. It is the combination of both these factors which leads to the potential savings.

When looking in isolation at the 'Sharpened incentive' Framework compared to the 'Current Position' (Figure 15), the largest savings are realised between 2030 and 2035, in the form of distribution network savings. The largest driver for the cost savings is the allocation of the DSR flexibility provider, which is used to alleviate local peak more often than in the 'Current Position' Framework; our assumptions on the scale of the DSR rollout are such that the biggest impact occurs after 2030. Moreover, in this Framework the locational signals are sharper, so distributed generation is built closer to demand than in the 'Current Position' Framework. The impact of this is more evident after 2030 as the volume of distributed generation contributing to the local peak (e.g. reciprocating engines, biomass, EfW, small scale CHP technologies) becomes sizeable after that year in the FES Two Degrees scenario. These savings could occur prior to 2030, but as we mention above, this would require both the flexibility services and the demand for these services to materialise earlier.

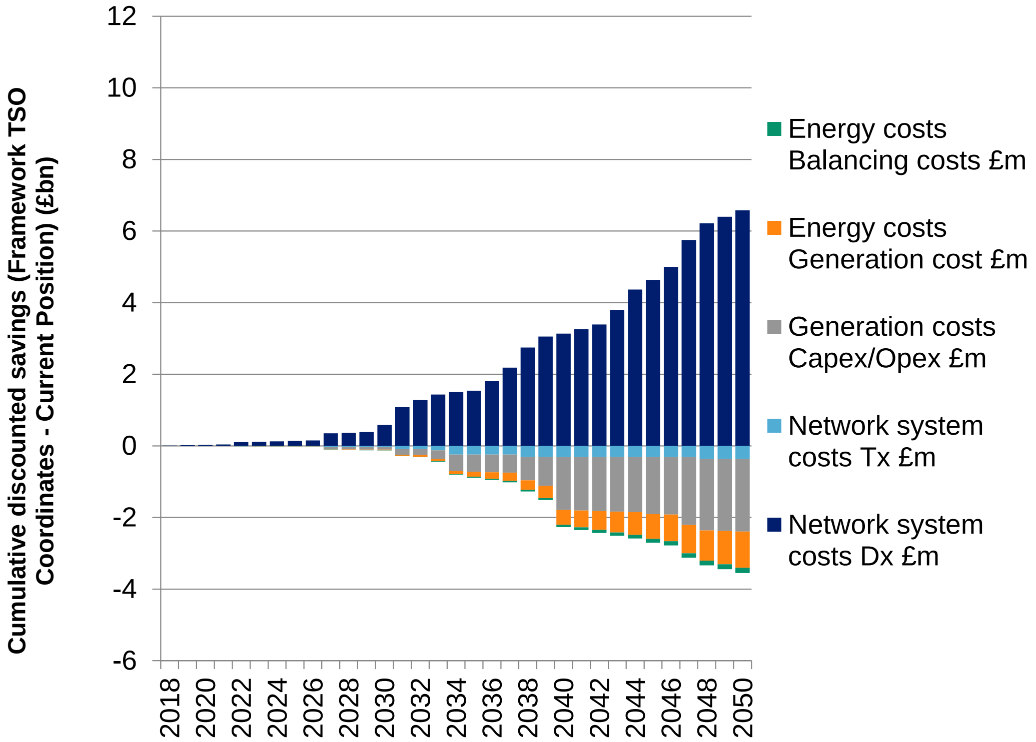
Figure 15 – Evolution of the cumulative discounted cost savings for the 'Sharpened incentives' Framework compared to 'Current Position'



In addition to the cost savings realised in the 'Sharpened incentives' Framework, the 'TSO coordinates' Framework (Figure 16) features higher cost savings on the distribution network costs due to the higher availability of ToU tariffs and commercial V2G, as provider of flexibility for the local peak. Section 2.2.3 contains a more detailed description of the impact of various sources of flexibility.

The aforementioned savings on the distribution network costs more than offset the extra costs in the form of generation and transmission network costs (e.g. caused by the lower contribution to the nation peak of ToU tariffs and commercial V2G, when compared to the 'Current Position' and the 'Sharpened incentives' Frameworks). In this Framework, the largest share of total system savings are realised in the 2040s as the large scale rollout of electric vehicles, coupled with the mentioned ToU tariffs and commercial V2G, becomes particularly incisive. Acceleration in the deployment of these technologies (provided that the demand is in place for flexibility services) should lead to additional savings through deferred network investments.

Figure 16 – Evolution of the cumulative discounted cost savings for the 'TSO coordinates' Framework compared to 'Current Position'



The 'DSO driven' (Figure 17) and 'Perfect information' (Figure 18) Frameworks display very similar patterns of cost savings over time, when compared to the 'Current Position' Framework. The additional cost savings compared to the savings in the 'TSO coordinates' Framework arise from the use of ToU tariffs, V2G and DSR, where local peak is prioritised more decisively, leading to substantial savings on the distribution network costs. Moreover the enhanced signals lead to a more targeted choice for the embedded generation location at all voltage levels. The majority of the cost savings incur stably over the period 2030-2050 and this is the result of the patterns of EVs and DSR rollout alongside our assumptions around ToU tariffs, as described in the previous paragraph.

Figure 17 – Evolution of the cumulative discounted cost savings for the 'DSO driven' Framework compared to 'Current Position'

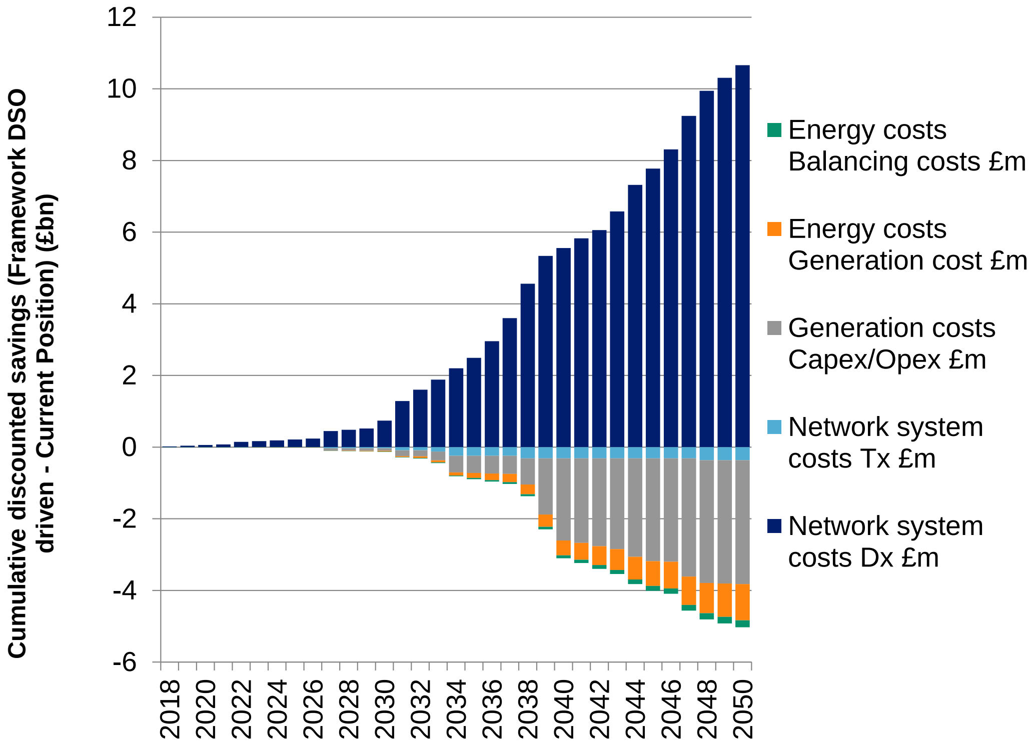


Figure 18 – Evolution of the cumulative discounted cost savings for the 'Perfect information' Framework compared to 'Current Position'

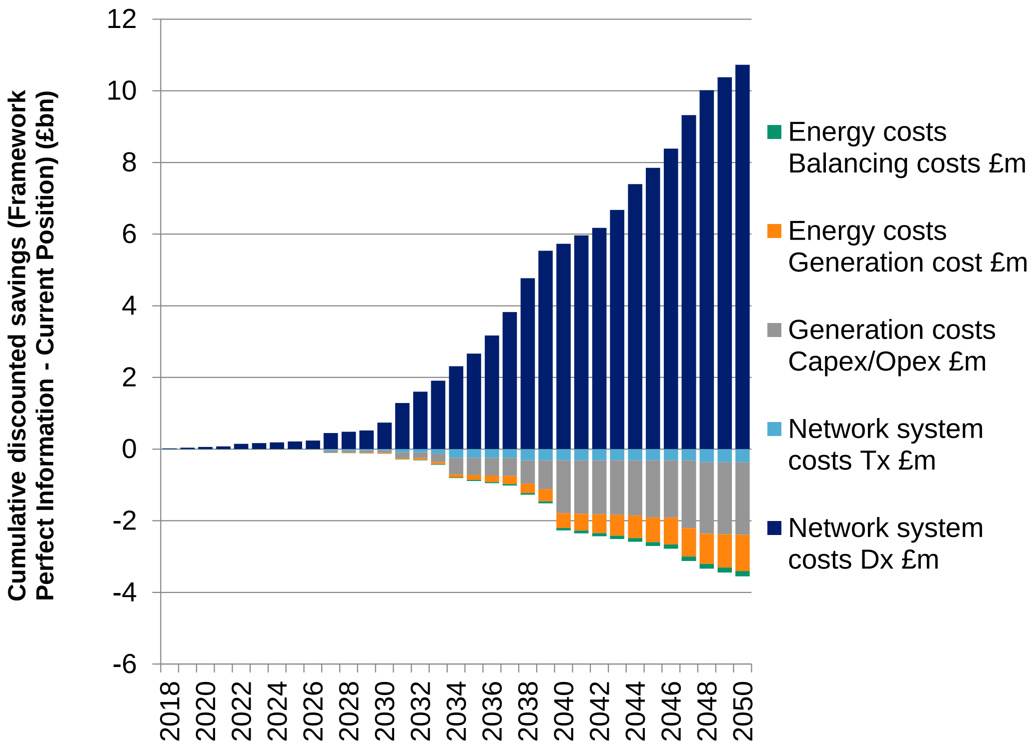
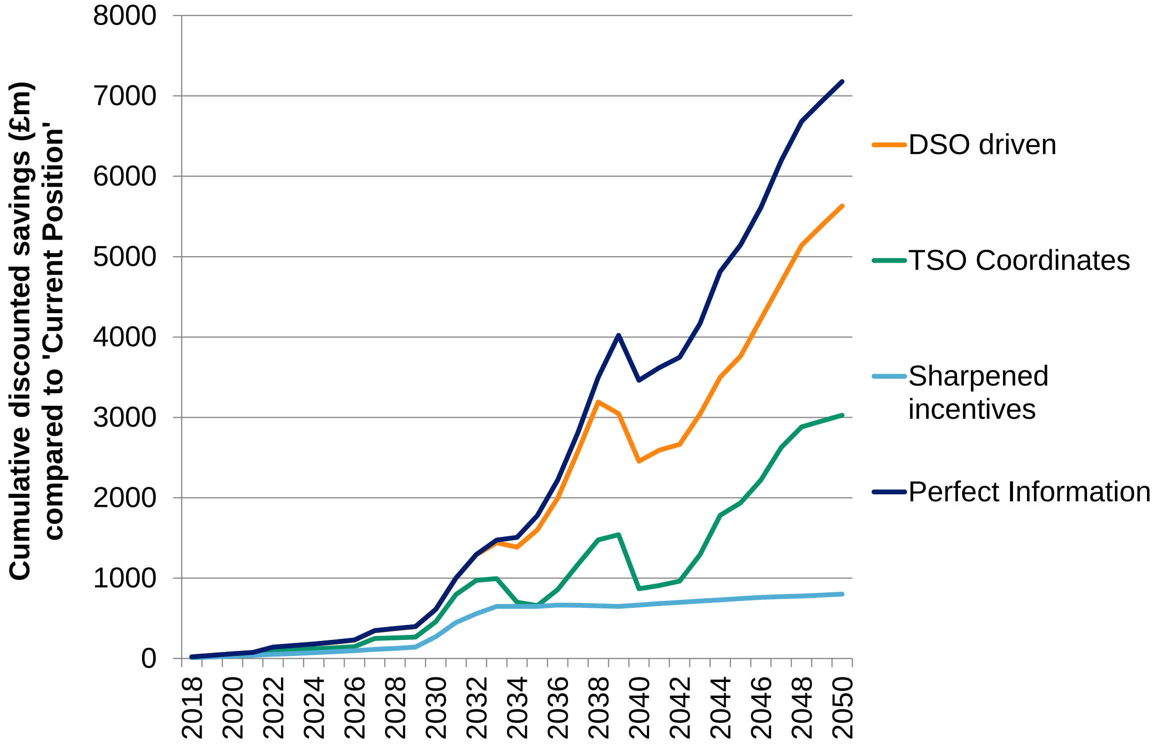


Figure 19 shows a summary of the overall savings in the different frameworks together. This shows that the DSO captures more value in the 2030s as demand exceeds available capacity due to the stronger electrification (and other developments) that begin in a more concerted manner beyond this point in time.

Figure 19 – Evolution of the cumulative discounted cost savings for all other Frameworks Framework compared to 'Current Position'



2.4 Modelling limitations

The starting point for the analysis is the Two Degrees scenario from National Grid's 2018 Future Energy Scenarios

We have only analysed one scenario (the FES Two Degrees scenario). The extent and timing of potential benefits from more active DSO Frameworks are specific to this scenario. If the pace of electrification, the balance of distributed resource or the proportion of resource that is considered flexible vary, then the relative benefits of Frameworks will also change.

The level of Flexibility is fixed within the FES Two Degrees scenario

The available flexibility from DSR is fixed across the scenarios. Therefore, the quantification does not consider whether Frameworks are more or less likely to encourage additional volumes of flexibility. Our qualitative analysis suggests that some Frameworks may be able to encourage higher volumes of DSR and therefore the benefits may increase.

We have treated the distribution system as a single stylised network

We have treated the distribution system as a single stylised network. In reality, individual DSOs may have very different network configurations and load / generation profiles. This means that the benefits may be unevenly distributed across the system. However, the principle remains that without an ability to compare the cost/value of using a particular resource for different actions, we will not realise the full benefits of flexibility for consumers.

We have used simplified cost assumptions

Our network options solutions are based on a generic cost of reinforcement or replacement. A more detailed model would be able to consider a wider range of network solutions that may alter the relative impact of different Frameworks

2.5 Summary

Our estimate of the quantitative benefits shows there is potential for large-scale cost savings.

Our results show that the 'Current Position' Framework features the highest cumulative total system cost at £563bn, over £7.2bn more expensive than the 'Perfect Information' Framework; and £5.6bn above the 'DSO Driven' Framework. From the results of this assessment the estimated savings will exceed the costs associated with developing the Frameworks[12].

Most of these savings result from taking advantage of flexibility services. We assume three categories of flexibility providers: 'Time of Use' (ToU) tariffs on EV charging (residential and commercial), 'Vehicle-to-Grid' (V2G) services from Commercial EVs; and 'Industrial and Commercial' DSR. Each of these sources is time dependent element and depending on the prioritisation of local or national peak the impact is different. Overall, the additional savings on the distribution network realised first through ToU tariffs and secondly through V2G and DSR more than offset the increase in generation and transmission network costs.

The ability to take advantage of these flexibility services will vary under each Framework, and it is this that drives the differences in the network cost savings. As we have shown in this section under Framework 2 (Sharpened Incentives) the improvements in charging arrangements drive distributed generation to be in more targeted areas (in regard to helping distribution constraints) which makes it better than Framework 1 (Current Position). Then in Framework 3 (TSO coordinates) there is increased coordination between the TSO and DSO, which drives much reduced network spend due to better flexibility access and use. These benefits are enhanced in Framework 4 (DSO driven) as the focus is on the DSO to solve the local peak ahead on the national peak – we identified a higher value from using local flexibility resources to address local network issues (due to lack of alternative options). Finally in Framework 5 (Perfect information) the additional benefits are derived from removing last of information asymmetry

It is important to note that the savings are associated with post 2030 benefits have a high degree of uncertainty. There are many reasons for this uncertainty. However the main uncertainty in our assessment results from the availability of flexible resources in the future. As we discussed earlier, our assessment depends of the assumptions of the Two Degrees scenario from National Grid's 2018 Future Energy Scenarios. Any outturn where flexibility resources are lower than those outline in this scenario will reduce any of the cost savings.

These 'savings' should be viewed with this in mind and considered alongside the qualitative assessment set out in Section 3.

Nevertheless, all of the FES scenarios feature some degree of demand growth (both TWh annual and GW peak) and electrification of heat and transport in the 2030's, so there will either be network reinforcement or some cheaper use of flexibility occurring in this timeframe. Hence it makes sense to have the DSOs incentivised to exploit any flexibility available.

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12 Although we did not cost the Frameworks (e.g. in terms of implementation) our savings are much greater that the costs developed by the ENA as part of its Impact Assessment

3. QUALITATIVE ASSESSMENT

In this section we present our approach to the qualitative evaluation of the Frameworks. As part of this assessment we consider a range of criteria, including impact on system costs (drawing on the outcome of the quantitative assessment) through to regulatory and institutional change.

3.1 Assessment approach

This qualitative assessment is a relative assessment rather than an absolute assessment. The relative assessment takes 'Framework 1: Current Position' as the baseline, with the other Pöyry Frameworks assessed by reference to Framework 1. A relative assessment approach was chosen because in our view 'Framework 1' is the most likely outcome in the absence of any significant decisions by policy makers and network companies. Essentially this is a business-as-usual approach. Then from this baseline we are able to assess the relative benefits of the more ambitious frameworks.

The qualitative assessment is structured around the assessment criteria described in Table 12. The assessment does not attach weightings to the different criteria to reflect perceptions of relative importance.

Finally, we have not included an assessment criterion relating to security of supply. This is on the basis that all the Frameworks are assumed to deliver required security standards in terms of both resource adequacy and network adequacy.

Table 12 – Qualitative assessment criteria

Criterion	Description
Efficiency	Focus on effects of the Frameworks on overall system costs and impact of each Framework on facilitation of low carbon resource on the electricity system. The potential to reduce overall system costs results in a positive assessment, while potential to increase overall system costs results in a negative assessment. The potential to increase low carbon generation access to the system results in a positive assessment, while potential to decrease low carbon resource accessing the system results in a negative assessment. This assessment draws on the cost related outcomes from the quantitative assessment summarised in Section 2.
Innovation	Focus on ability for Framework to encourage innovative solutions in terms of business models, offerings, platforms for trading etc. The potential to increase innovation results in a positive assessment, while potential to decrease innovation results in a negative assessment.

Criterion	Description
Regulatory / institutional change	Focus on scale of regulatory / institutional change required for a Framework. The frameworks are scored on the level of regulatory / institutional change compared to the counterfactual (Framework 1). A greater level of complexity and regulatory risks for stakeholders will therefore result in a more negative assessment. We assume no positive score for this criterion, since all Frameworks will require a change from the status quo.
Implementation	Focus on scale of implementation challenge for a Framework. The frameworks are scored on the level of implementation challenge compared to the counterfactual (Framework 1). The potential to make implementation more difficult / less practical / less swift results in a negative assessment. We assume no positive score for this criterion, since all Frameworks will require a change from the status quo.

Table 13 describes the scoring approach for the qualitative assessment.

Table 13 – Qualitative assessment scoring description

Scoring	Description
✓✓	Marked benefit
✓	Benefit
(✓)	Modest benefit
-	Neutral
(✗)	Modest dis-benefit
✗	Dis-benefit
✗✗	Marked dis-benefit

3.2 Assessment

The assessment in this Section is on the basis that resource capable of providing flexibility is delivered as envisaged within the FES Two Degrees scenario, which has formed the basis for the assessment undertaken in this report. This means that flexibility is assumed to be available to be used in the most appropriate manner based on the drivers in place in a particular Framework.

However, there is a degree of deliverability uncertainty in respect of future sources of flexibility. If sources of flexibility are not delivered as envisaged, the feasibility of different Frameworks and the potential to realise the benefits that they offer could be adversely affected. This potential will also depend on strong consumer engagement. This section focusses on the structural changes than will be necessary in the market to allow flexibility to be utilised. But at the same time it will be the responsibility of electricity market stakeholders (including network companies and, regulators) to continue to educate and incentivise consumers to embrace the expected opportunities. Section 4 returns to this point.

As part of our assessment we have attempted to catch any unintended consequences that may result from each of our Frameworks, and lead to impacts on the overall energy transition. For example this will include the trade-off between the savings identified in Section 2 and the increased complexity of regulatory and institutional change. The greater scale of change is likely to lead to the opportunity for more unknowns and unintended consequences.

3.2.1 Summary assessment

Table 14 provides an overview of the assessment of the Frameworks relative to Framework 1, across all of the assessment criteria introduced in Section 3.1. Detail on the rationale for the assessment for each of the criteria is provided in the subsequent Sections.

Table 14 – Summary of qualitative assessment relative to Framework 1

Criterion	Framework 2: Sharpened incentives	Framework 3: TSO Coordinates	Framework 4: DSO driven	Framework 5: Perfect Information
Efficiency	-	(✓)	✓	✓✓
Innovation	(✓)	✓	✓✓	✓✓
Regulatory /institutional change	-	(×)	×	××
Implementation	-	(×)	×	×

3.2.2 Efficiency assessment

The assessment of relative efficiency focuses on the implications of the Frameworks on overall system costs to 2050. This draws on the quantitative analysis discussed in Section 2. The results of the assessment are set out in Table 15.

In terms of overall efficiency, the scope for reducing distribution network related costs is the main source of benefit. Given the scale of potential savings in this area, solutions which promote it offer scope for enhanced efficiency overall, with increases in other cost categories more than offset by the distribution cost savings available.

Our assessment also takes account of the growing divergence between local and national peaks and the higher cost of mitigating through reinforcement at distribution level.

Frameworks which have a more prominent role for DSOs allow for greater consideration of distribution related costs and, for this reason, are considered to perform better in terms of overall system efficiency. Framework 5, with its optimised flexibility provider and enhanced information transparency, is considered to be the best able to extract this value. Framework 4 offers the next best solution in this regard.

Finally we consider the impact of the decarbonisation relative to today's system. The relative performance of each of the Frameworks is, therefore, expected to contribute to only relatively minor differences in terms of achievement of decarbonisation goals. For example network capability will influence ability to accommodate exports from renewable generation. There is the potential for curtailment of renewable output in cases of reduced network capability, and a result of this curtailment will be the requirement to build additional generation to meet demand and ensure RES targets are still met. Ultimately it is the differences in the cost of meeting the targets, rather than the level of decarbonisation achieved, that drives the assessment.

To a large extent this curtailment is a direct result of the underlying FES two-degree scenario assumptions in respect to Solar PV[13]. Therefore while we consider this impact within our assessment, a change to the underlying assumptions may mitigate the need to curtail and build the additional generation (at additional cost) needed to compensate from the lower RES generation.

Relative to Framework A, most of the other Frameworks are expected to have a slightly worse performance in terms of decarbonisation. This is due to the potential for increased requirement for increased renewable output curtailment due to the lower network capacity.

13 The FES Two-Degree Scenario assumes approximately 40GW of solar generation connected at the distribution level. If this capacity was to be connected at transmission level then the need for curtailment of Solar PV would be reduced. However, this may lead increased connection costs.

Table 15 – Qualitative assessment for efficiency criterion relative to Framework 1

Criterion	Assessment	Comment
Framework 2: Sharpened incentives	-	This Framework is broadly comparable to Framework 1 in terms of overall system costs. Sharpened incentives through charging arrangements do allow for some overall system cost savings.
Framework 3: TSO Coordinates	(✓)	This Framework offers modest system cost savings relative to Framework 1. TSO coordination provides scope for overall system cost savings, mainly linked to reduction in distribution system costs. While this saving is partially offset by cost increases in other areas, the net position is a modest reduction in overall system costs. And the potential for some renewables curtailment resulted in the need for an additional 1GW of onshore wind generation is required by 2050 to ensure RES targets are met.
Framework 4: DSO driven	✓	This Framework offers system cost savings relative to Framework 1. The scope for cost savings in the DSO driven solution is again primarily linked to the potential for reductions in distribution system costs. These are more sizeable than in Framework 3 as the DSOs have greater control over the use of flexibility and so have greater ability to use it to offset distribution network costs. Elsewhere, generation capex/opex costs reflecting need for alternative resource to support national peak. But the net position is still one of reduction in overall system costs. Finally using flexible resource for local peak management may increase likelihood of curtailment of renewable resulting in the need for an additional 1GW of onshore wind generation is require by 2050 to ensure RES targets are met.

Criterion	Assessment	Comment
Framework 5: Perfect Information	✓✓	This Framework offers greatest overall system cost savings relative to Framework 1. Again, potential for distribution cost savings are the primary benefit. However, enhanced information transparency and coordination means that generation related costs are lower than for Framework 4. And although this model assumes perfect information there is some increase in in the potential for renewables curtailment compare to Framework 1. Our modelling resulted in the need for an additional 1GW of onshore wind generation is required by 2050 to ensure RES targets are met.

3.2.3 Innovation assessment

The context for this assessment assumes the continued existence of incentives created by the RIIO framework for network innovation and initiatives for smarter network operation encouraged by the Clean Energy Package.

All Frameworks are expected to enhance the potential for innovation from the network businesses and/or flexibility resource providers. Innovation could be seen in terms of solutions offered and business models for realising value. Framework 5 is likely to offer the greatest potential for innovation as it offers the route for optimised flexibility deployment across the system as a whole. The ability to consider different calls for flexibility without a default prioritisation creates an environment in which innovation can be fostered where it is for the good of the system collectively.

However, for each of our Frameworks it is important that there are appropriate incentives on customers in place. Our modelling of the FES Two Degrees scenario implies certain levels of response to TOU tariffs, however if these TOU tariffs fail to be developed, or if customers do not respond to them in the manner expected, the flexibility and innovation will not materialise.

The results of the assessment are set out in Table 16.

Table 16 – Qualitative assessment for innovation criterion relative to Framework 1

Criterion	Assessment	Comment
Framework 2: Sharpened incentives	(✓)	This Framework has potential to result in modest benefits in terms of innovation relative to Framework 1. Sharpened incentives via charging arrangements are expected to influence resource siting decisions in a way that has potential to better support the network. But these incentives may also encourage uptake of different or enhanced technology offerings that are able offer benefits to the system. We also take account of the risk that these proposed reforms may not fully deliver against Ofgem's objective. Limited impact in terms of incentives for network businesses to adopt innovative solutions relative to Framework 1, however.
Framework 3: TSO Coordinates	✓	This Framework has potential to result in benefits in terms of innovation relative to Framework 1. Scope for greater coordination between network businesses offers potential for enhanced innovation in respect of development and operation of the system as a whole. In this Framework, the focus is more TSO focused than under Framework 5, however.

Criterion	Assessment	Comment
Framework 4: DSO driven	✓✓	This Framework has potential to result in benefits in terms of innovation relative to Framework 1. With DSOs taking the lead in this Framework, the expectation is that innovation will be centred mainly on ways in which to enhance distribution network operation and development or to provide solutions tailored to DSO requirements. The underlying architecture of Framework 4 may facilitate more, smaller, players emerging due to the local flex market participation On the assumption that the potential for innovation is greater across the distribution networks collectively given their size, relative to the transmission networks, the expectation is that this Framework offers greater benefit from innovation than Framework 1.
Framework 5: Perfect Information	✓✓	This Framework has potential to result in marked benefits in terms of innovation relative to Framework 1. Enhanced coordination and optimisation means that this Framework is expected to offer the greatest potential for innovation in terms of business models and technical solutions from flexibility providers, as well as more innovative requirement specification and procurement across the network businesses via the flexibility provider.

3.2.4 Regulatory /institutional change assessment

Here, the focus is upon the scale of regulatory and institutional change needed to deliver the different Frameworks. Relative to the continuation of the 'Current Position' under Framework 1, all other Frameworks involve some degree of regulatory / institutional change. The estimated scale of change is modest in the case of Frameworks 2 and 3, as they are evolutions of the arrangements in place today (and under Framework 1).

However, the estimated scale of change increases through Framework 4 and is greatest Framework 5, with both involving more substantial changes in roles and responsibilities, with implications for the required regulatory and institutional underpinnings for the system.

However the mechanisms needed to develop these pathways, allowing them to facilitate innovative solutions, requires significant changes both from institutional, ie legal and regulatory, point of view and in terms of the significant business change required within the companies themselves. These changes would need to consider the ongoing appropriateness of the RIIO framework, and particularly the core funding mechanisms. For example, this will range from ensuring that non-asset solutions continue to be appropriately included within the incentive reward mechanisms (administered by the regulator), to developing new funding to support new flexibility coordinators or separate distribution system operators. Another issue will be incentivising investment in distribution network to provide benefits to the transmission network (or vice versa).

Therefore there must be a clear case that the benefits will outweigh the negative consequences. For example, there are clear benefits when comparing Framework 4 and Framework 1 – these benefits clearly outweigh the potential regulatory / institutional challenges and risks. However, the relatively small difference in benefits calculated between Framework 4 and Framework 5, means that policy makers would have to think carefully before moving towards Framework 5 - given the significant regulatory / institutional change require under this framework.

The results of the assessment are set out in Table 17.

Table 17 – Qualitative assessment for regulatory /institutional change criterion relative to Framework 1

Criterion	Assessment	Comment
Framework 2: Sharpened incentives	-	Our assessment of this Framework indicates that any impact would be neutral from a regulatory /institutional change relative to Framework 1. In this Framework, the main regulatory / institutional change relates to creation of charging arrangements across transmission and distribution that provide coherent and effective signals for resource providers to respond to across the piece. The need for compatibility and coherence requires development of the supporting regulatory arrangements. However, because this process is currently ongoing and as a result we have assumed the necessary regulator / institutional arrangements are in place to implement any recommendations These types of changes are expected to be incremental to the existing framework.
Framework 3: TSO Coordinates	(×)	This Framework has potential to result in modest dis-benefit in terms of regulatory / institutional change relative to Framework 1. This Framework is likely to require evolution of the interfaces between TSO and DSOs. To allow for increased coordination. However, with this effectively an evolution of the existing arrangements, with the TSO in the vanguard, it is considered as an incremental development in terms of regulatory /institutional change. The Framework may also require additional regulation to monitor the decision taken by the TSO. This would seek to provide transparency as to why one decision was made over another, whether this is to explain flexible vs. traditional decisions or the decision to activate ‘Flexibility in Region 1’ vs. ‘Flexibility in Region 2’.

Criterion	Assessment	Comment
Framework 4: DSO driven	×	This Framework has potential to result in dis-benefit in terms of regulatory / institutional change relative to Framework 1. As this Framework places DSOs at the heart of the arrangements, as opposed to the TSO, it is expected to require more significant institutional and business change to develop appropriate underpinnings for roles and responsibilities. In addition locational markets for flexibility could lead to market power issues. These issues would also need to be considered by the regulator.
Framework 5: Perfect Information	××	This Framework has potential to result in marked dis-benefit in terms of regulatory /institutional change relative to Framework 1. This Framework involves the creation or formalisation of the flexibility provider role which has access to all relevant information and required tools needed to optimise the system. This is expected to require the most substantial shift in terms of institutional and business change. This Framework will also require regulatory decision as to which party has responsibility for the ensuring network security. If this is not the flexibility coordinator, then clear processes would need to be in place between the coordinator and TSO to ensure system security standards (e.g. frequency control) are met.

3.2.5 Implementation

This criterion focusses on the implications for IT systems and working processes. The outcome of the assessment follows a similar pattern to that identified during our assessment of regulatory / institutional change, with Framework 4 and Framework 5 requiring the most significant degree of change.

In our view the systems required may not differ significantly across the Frameworks. However, the scale of the challenge, in terms of calling on distributed resources, is likely to be smaller in TSO coordinates as there is more distribution network build, which means that there are fewer issues to resolve at distribution level and less need for flexibility to be used to resolve distribution issues.

Therefore it is our expectation that the systems require in the in a TSO led framework would be easier to implement that in Framework 4 and Framework 5 (e.g. the level of active engagement across the DSOs is likely to be higher in these frameworks).

The results of the assessment are set out in Table 18.

Table 18 – Qualitative assessment for implementation criterion relative to Framework 1

Criterion	Assessment	Comment
Framework 2: Sharpened incentives	-	This Framework is broadly comparable to Framework 1 in terms of implementation challenge. As this is an evolution of Framework 1, the scale of implementation workload linked to new systems and working procedures is expected to be limited.
Framework 3: TSO Coordinates	(×)	This Framework has potential to result in modest dis-benefit in in terms of implementation challenge relative to Framework 1. As this Framework involves greater coordination, albeit with the TSO still in the lead, the scale of implementation workload us expected to be more significant than for Frameworks 1 and 2. New systems and working procedures will be needed to allow for required information sharing and amended decision making processes.

Criterion	Assessment	Comment
Framework 4: DSO driven	×	This Framework has potential to result in dis-benefit in in terms of implementation challenge relative to Framework 1. The scale of the implementation challenge is expected to be more significant for this Framework, as it requires systems and processes to be more radically revamped to allow for information flows to multiple DSOs and optimisation processes that work across the different stakeholders involved. The interaction of multiple DSO could also lead to increase complexity on how to efficiently manage flexibility resources. These relationships between the different DSOs will be particularly challenging when flexibility is required in areas close to the DSO boundaries. In addition, the increasing numbers of Independent Distribution Network Owners (IDNOs) may also increase the challenge of managing the flexibility resources.
Framework 5: Perfect Information	×	This Framework has potential to result in dis-benefit in in terms of implementation challenge relative to Framework 1. Again, the scale of the implementation challenge is expected to be more significant for this Framework given the need for systems and information flows that allow the flexibility provider to acquire and process different calls for flexibility and then to optimise its deployment across the system as a whole. The scale of the challenge could potentially increase if multiple flexibility providers existed.

3.2.6 Deliverability/realisation

As introduced at the start of this Section, the qualitative assessment has been conducted on the basis that the flexible resource envisaged within the FES Two Degrees scenario is indeed realised and available for use. However, if delivery of envisaged levels of flexibility is not forthcoming, the drivers for adopting different Frameworks are not necessarily as clear and the benefits available through them will be altered.

If quantities of distributed resource on the system are lower than anticipated in FES Two Degrees, then the potential for multiple applications of flexibility resources may be reduced. For example, the drivers for the increased DSO participation and coordination envisaged in Framework 4 and Framework 5 are likely to be reduced in this context, along with the benefits of adopting these solutions.

In such an eventuality, the ability for and value of distribution network capex to be offset by flexibility would be reduced. Indeed, the Frameworks that are closer to today's arrangements (e.g. Framework 2 and Framework 3), with more conventional distribution network investment and less reliance on flexible resources as an alternative, are likely to be needed in this situation. In fact there are still many benefits associated with developing these frameworks, even in the case of lower deliverability of flexibility. For example the lower level of flexibility will still lead to reductions costs at peak times under these frameworks. In addition these frameworks will offer many more opportunities for consumer engagement than under business as usual. This consumer engagement may then act as a catalyst for developing and deploying greater levels of flexibility.

3.3 Summary

This section has considered how the 'Frameworks' compared again the 'Current Position' across a range of assessment criteria. The results of this assessment have identified that there is not one 'perfect solution' to be followed. Our assessment shows fairly balanced results with each Framework having both positive and negative aspects. For example, in Framework 5 (Perfect Information) the assessment identifies clear benefits in regard to cost savings and innovation opportunities – but this comes at a cost of increased challenges in institutional and business change and implementation of the Framework. The opposite can be true of those Frameworks closer to the 'Current Position' – e.g. Framework 2: Sharpened Incentives'.

It is also clear the relative merits of each 'Framework' will depend on the underlying market assumptions. For example we see that the benefits of these Frameworks will be influenced by the wider development of flexibility resources. Many of the benefits associated with Framework 4 and Framework 5 result from the increased use of flexibility resources in the market, therefore it makes sense that if these flexibility resources do not materialise the benefits from these Frameworks will decrease. Then it also follows that many of the negative aspects of Frameworks 2 and Framework 3 will not be as important in a low flexibility world.

This leads to clear implications for the timing and development of the Frameworks. Making it critical that as the electricity market evolves decision on which Framework to follow should reflect a 'least regrets' approach. This must involve careful consideration of the transition between the different Frameworks over time. This transition will need to reflect the status of the electricity market at any point in time, but must be flexible enough to react to market developments. For example, it is expected that a large proportion of the flexibility resources identified in the report will not be available until the 2030's at the earliest and possible later. This is a result of the demand forecasts used within the FES scenarios; however the flexibility benefits will start to accrue when demand exceeds network capacity and any impact on the timing of electrification of transport and heat will affect when this happens. Therefore the structure of the market must move beyond the 'Current Position' to able it to make use of the flexibility once it is deployed.

Based on our assessment it would seem sensible to pursue 'Framework 2' and 'Framework 3' in the short to medium term, and then moved towards 'Framework 4' or 'Framework 5' depending on the growth of demand and the speed and scale of the development of flexibility resources.

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4. CONCLUSIONS AND RECOMMENDATIONS

This Section presents the key insights and findings associated with our assessment (this considers both our quantitative and qualitative assessment). Finally we set out our recommendations.

4.1 Key insights and findings

Impact of diverging peaks can lead to inefficient solutions

The lack of coincidence between local and national peaks leads to the possibility of inefficient system solutions when the same resource can be used to address network issues at both levels. This increases the cost of the electricity networks.

This risk is likely to increase in the future as the energy transformation results in increasing divergence between local and national peaks and (in particular) a growing volume of cost-effective flexibility being located in the lower voltage networks – leading to demand exceeding network capacity[14].

The real costs from not addressing this inefficiency only start to arise around 2030. This is the point at which the increased sourcing of flexibility at the distribution level and the constraints on network capability start to exacerbate the national/local divergence.

Local flexibility resources should be used at the local level

In general, there is a higher value from using local flexibility resources to address local network issues (due to lack of alternative options) and frameworks that do not acknowledge this, or ensure this higher value can be signalled, will lead to higher costs.

Network investment is the main driver of cost differences across our Frameworks

Our assessment shows that differences in network investment costs drive the differences between the Frameworks. In particular, Frameworks that allow a greater use of local flexibility sources to reduce the need for reinforcement on the LV network will be able to deliver a lower cost system.

The 'Current Position' Framework features the highest cumulative total system cost at £563bn, over £7.2bn more expensive than the 'Perfect Information' Framework. While this is a small difference in percentage terms, we believe these savings are linked to real gains on the system. For example, these cost savings are due to more efficient use of flexibility within the electricity system - leading to lower distribution network costs. This will result in less system assets (e.g. transformers) being replaced by the network operators.

14 It is worth noting that if the electrification of heat and transport is causing the increase in demand, then the additional flexibility will arrive at the same time.

Revealing the true value of flexibility to the distribution or transmission system will deliver the greatest benefits

Frameworks that more accurately and transparently signal the true value of flexibility to the distribution or transmission system will deliver the greatest benefits. However, since these require more fundamental changes in information/data flows, commercial arrangements and regulatory incentives, the implementation costs will be higher and the time to implement may be longer. The degree of imperfection is across several aspects:

- **Where best to locate?**: This is reflected in the charging arrangements and whether they are signalling what costs are associated with locating in a particular site[15], and also how dynamically they are adapting to changes in the underlying supply-demand mix. However, these decisions are, in the main, independent of the structure of the DSO framework and therefore should be pursued anyway.
- **What flexibility can be provided?** Are individuals or aggregators able to tell the SOs what they are able to offer and when and at what price?
- **What is the additional cost?** Is the DSO able to tell the TSO how much additional cost they will incur if a balancing action is taken for national purposes (and vice versa)?

The 'Frameworks' share many of the same features

The different Frameworks share many of the same features and therefore it may be possible to transition from one to another without too much disruption. We discuss these transition 'Roadmaps' in our recommendations in Section 4.2.

15 In some cases the location issues will be automatically solved e.g. electrification will place the source of demand and flexibility in the same place. However this will not always be the case and on many occasions the net growth in demand will outweigh the new flexibility leading to additional reinforcement, or other local energy sources, being required.

4.2 Recommendations

We propose a phased transition in the TSO-DSO Framework

A phased change in the TSO-DSO Framework may be more appropriate given the uncertainty over the speed and extent of the wider decarbonisation programme and the risk of stranded costs and programme failure if major institutional and commercial platform changes are introduced too quickly. This would be linked to when load growth reaches the point of driving the need for widespread network reinforcement or the use of flexibility, which the FES shows happening from 2030 onwards.

This transition between the Frameworks will need to reflect the status of the electricity market at any point in time, but must be flexible enough to react to market developments. Any roadmap should promote more transparent data and price signals to enable the trade-offs between competing uses of DER to be assessed more holistically. From our analysis there appears to be a 'no-regrets' decision to move towards 'Framework 3 – TSO Coordinates' in the short term. This Framework focusses on the TSO leading system optimisation, but works alongside the DSO to ensure a balanced approach towards meeting national and local requirements:

- **Roadmap Phase 1 – TSO Coordination (Implementations of Framework 3)**: This phase of the roadmap will lead to the implementation of Framework 3 immediately. This Framework will allow the development of appropriate systems to facilitate the use of flexibility resources by both the DSO and TSO. The increasing role of the DSO will also encourage innovation from other market participants in the types of flexibility services being offered into the market. The extent to which Framework 3 will continue will depend on the speed of electrification and the scale of flexibility services being offered to the market.

As a result, many of the systems required for the DSO to take an active role in the market will be developed as part of this Framework. From here, and as evidence is gathered, the second phase of the Roadmap – the longer-term transition – may continue down one of two paths, reflecting either Framework 4 or 5:

- **Roadmap Phase 2a: Move towards a DSO led system (Framework 4)**. This branch of the Roadmap will be triggered by increased need for the DSO to take a lead in the coordination and activation of flexibility services in order to actively balance the system to address the local peak. With more activity occurring on their systems, the ability to react more precisely at a more granular level to the resource in their networks, will make direct control by DSOs more cost-effective. Therefore, over time, the coordination role of the TSO will be reduced as more of the actions are resolved at a local level first. However, the regional focus (e.g. DSO regions) may lead to sub-optimal decisions and outcomes as the scale of electrification increases.
- **Roadmap Phase 2b: Move toward a 'Flexibility Coordinator' (Framework 5)**. This branch of the Roadmap may develop from Roadmap Phase 1 in response to significant electrification and the associated opportunities. The move towards Framework 5 would arise if the coordination of the TSO was seen as inefficient because of ongoing information asymmetries between the two groups of network operators. To address the conflicts that may arise in terms of prioritising resources between a separate DSO and TSO the development of a single market for all flexibility resources with all information (about flexibility provision and system optimisation requirements) would be established and access would be freely available to whoever is given the role of system optimisation.

Innovation should continue to be encouraged under RIIO-2

Incentives under the RIIO-2 regime, and more generally from government, should continue to encourage market participants and DSOs to consider innovative non-asset solutions to network issues. For example, electrification of transport is a key driver of increased demand, and so as this demand increases, managing EV charging efficiently will be a key innovation.

It is our expectation that innovation will be centred mainly on ways improve customer service through enhanced distribution network operation and development or to provide solutions tailored to DSO requirements – ultimately minimising network costs. This is based on the assumption that the potential for innovation is greater across the distribution networks collectively given their size, relative to the transmission networks.

Cost reflective charging will help to mitigate demands for higher network investment

Though we have not been able to fully quantify the impact, a more cost-reflective set of charging arrangements, can mitigate some of the demands for higher network investment.

To the extent that Ofgem's Significant Code review for targeted Charging Ofgem charging reforms will improve the efficiency of locational signals for new distributed resource then these should be supported.

The need for strong consumer engagement must not be underestimated

It is clear that the future will require significant change across the energy sector. And it is important that this change takes account of requirements and behaviour of consumers. There is a risk that industry changes for the sake of itself and without proper consultation with a wider range of consumers to understand their needs and potential behaviour. For example, would we expect consumers to be directly involved in switching demand or should this be automated for them (in ways that also save the customer and the supplier money)?

This will require more research into customer behaviour, and while there have been a number studies which consider consumer participation (mainly as part of the innovations schemes e.g. LCNF / NIC) these customers studies tend to face a bias because the consumers taking part, wish to take part.It will be crucial to ensure that consumers are engaged, and to do this there must be benefits. This will include both direct benefits such as financial savings, in addition to indirect benefits such as helping to achieve reduction in CO_2.

Finally, it will be important that the industry is able to continue to educate consumers as we move through the transition. Consumers will require advice such as how they can benefit from different technologies, and advice in understanding new billing arrangements (e.g. due to increased interaction with network services and potentially the implementation of locational marginal pricing).

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Pöyry Management Consulting

King Charles House
Park End Street
Oxford, OX1 1JD
UK

Tel: +44 (0)1865 722660
Fax: +44 (0)1865 722988
www.poyry.com/energyconsulting
E-mail: consulting.energy.uk@poyry.com

PÖYRY

Pöyry Management Consulting (UK) Ltd, Registered in England No. 2573801
King Charles House, Park End Street, Oxford OX1 1JD, UK

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