transition

Moving to a smart future

In partnership with LEO Local Energy Oxfordshire

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Oxfordshire Programme Commercial Arrangements

Scottish & Southern Electricity Networks

Contents

Executive Summary

The way we consume and generate electricity is changing at unprecedented pace. Alongside and driving this change the UK government, signalled its stance on climate change as the world's first major economy to pass laws to end its contribution to global warming by 2050 (Gov.UK, 2019). The Government's current climate change strategy outlines: a quadrupling in UK renewable capacity since 2010, installation of 2.5 million energy efficiency measures, £4.5 billion to support renewable and low carbon heating and £1.5 billion to support electric vehicle uptake (Gov.UK, 2019b) with net zero only expected to complement and accelerate such targets.

Such momentous change and ambitious targets pose significant opportunities for businesses and individuals in both the way they use their energy and their participation in innovative new markets.

As the UK's generation mix becomes increasingly reliant on renewable technology the system's ability to flex from the supply side (as traditionally operated through fossil fuel powered plants) will be diminished[1] with an increased requirement on flexibility at the demand side to keep supply and demand within balance. At the opposite end of the electricity system the way in which households consume their energy is changing with distributed generation (such as solar PV) supporting local communities, increased demand and storage capabilities through electric vehicles and other new technology; and improved IT infrastructure in the form of smart meters and automation technologies. Commercially this change must be facilitated through new markets, economic concepts and smart pricing (i.e. time of use tariffs).

The electricity networks (Transmission and Distribution) will be a key facilitator of these new technologies and are likely to see the brunt of increased strain through less reliable and more distributed generation, challenging system balancing. At the same time the physical assets responsible for carrying electrons around the system will see widespread increases in demand[2], especially at local distribution levels. In order to effectively operate this system, to continue to guarantee security of supply, and to avoid or defer (and effectively schedule) network reinforcements, the electricity system will increasingly need flexible resources[3] that can help balance supply and demand (alongside other system needs i.e. frequency, reactive power) at both national and local levels.

The more optimally the UK can operate its flexibility resources:

1) The less need there will be for excess generation to cope with peaks in demand (flexibility will create a flatter and more malleable curve for electricity demand). Generation is currently procured by electricity suppliers, a cost reflecting about 32% of a domestic customer's bill (Ofgem 2019).

2) The more reliably and cost-effectively the system can be managed (currently operated through National Grid Electricity System Operator, NGESO, and paid for through

[1] Through reduced control and reliability.
[2] Through electrification of transport and heat.
[3] Typically distributed generation storage or demand response, are connected to the electricity network, and are flexible in how they operate and impact the network. (ON-PRJ-WS2-P3)

Balancing Service Use of System (BSUoS) charges) i.e. through increased competition and market entry by new technologies to drive efficient markets.

3) The less need and disruption there will be from network reinforcement (reflected through cost-effective Transmission Use of System (TUoS) charges and Distribution Use of System DUoS charges).

SSEN's TRANSITION project working with Electricity North West Ltd (ENWL) and alongside, Western Power Distribution (WPD) on the EFFS (electricity flexibility and forecasting system) project, and Scottish Power Energy Networks (SPEN) on the FUSION project (together the TEF projects) are feeding directly into the Electricity Networks Associations (ENA) Open Networks project (ON-P). Open Networks brings together the nine British and Irish networks operators, the energy regulator Ofgem, respected academics, and NGOs to deliver the UK's smart grid.

Within TRANSITION's trials, deployment of Distributed Energy Resources (DER) will be tested through a range of technical, commercial and IT based solutions. This report provides an introduction to the commercial analysis required on TRANSITION to both test new initiatives and facilitate technical and IT learning.

Namely the report addresses issues surrounding valuation of flexibility resources and how TRANSITION is challenging conventions to help stimulate the market for DER. Particular focus is given to the notion of willingness-to-pay (WTP) vs willingness to accept (WTA) methodologies with reference made to the support of smarter auction mechanisms. The report also builds on contractual arrangements (initially delivered by the ENA ON-P) and associated flexibility service requirements (i.e. baselining, service stacking) to produce template legal agreements needed to run TRANSITION's trials.

Stakeholder feedback was sought throughout and will continue to be gathered as project outputs evolve. Expert consultant support was sought in the development of peer-to-peer (P2P) services in particular to effectively assess market opportunities. Finally, a cross-reference has been performed against TRANSITION's wider delivery package to ensure consistency with the projects market rules, the Neutral Market Facilitator (NMF) and the Whole System Coordinator (WSC).

1. Introduction

1.1 Background

TRANSITION is an Ofgem Electricity Network Innovation Competition (NIC) funded project, led by SSEN in conjunction with our project partners ENWL, CGI, Origami and Atkins.

TRANSITION, based on the outputs of Open Networks, will inform the design requirements of a Neutral Market Facilitator (NMF) and Whole System Coordinator (WSC), develop the roles and responsibilities within the marketplace, develop the market rules required for the trials, and implement and test the concept of the systems by means of trials in Oxfordshire.

The TRANSITION NIC project gained Ofgem funding as part of a collaboration agreement between TRANSITION (SSEN), EFFS (WPD project) and FUSION (SPEN project), known in the industry as TEF.

In addition, the project is also closely collaborating with the Local Energy Oxfordshire (LEO) project, a UK Industrial Strategy funded project. Both TRANSITION and LEO have objectives that are closely aligned and when combined significantly enhance the overall learning.

The project is expected to run for several years and is seen by SSEN, its partners and wider industry as one of the most critical developments to date in the transition to Distribution System Operators. Its findings will be shared collaboratively across industry, academia and with policy makers and regulators, helping inform and influence the energy system of the future.

The above description focuses on Projects TRANSITION and LEO which is the primary project for most external stakeholders. However, it is useful to note the various ways in which the Oxfordshire Programme is viewed so we can adapt and interact accordingly.

- **Customers and most External Stakeholders** – Project LEO is the lead, with TRANSITION effectively Work package 5 of LEO. MERLIN very much sits behind TRANSITION.
- **DNOs, TOs, ESO, IDNOs, ENA and Ofgem** – These stakeholders see TRANSITION as the primary project and the T in TEF which brings together the three industry DSO demonstrators, TRANSITION (SSEN, supported by ENWL), EFFS (WPD) and FUSION (SPEN). MERLIN is a noted project and future feed into Open Networks[4]. Project LEO is a wider industry project enhancing the learning from TRANSITION, with all relevant learning coming through TRANSITION.
- **Internal Stakeholders** – Projects TRANSION, LEO and MERLIN are viewed together as the Oxfordshire Programme. Connections have more input into Project LEO while most other teams are and will continue to have more interaction with TRANSITION and MERLIN. However, to avoid confusion and support transparency, it is being presented as a single programme of work.

[4] MERLIN looks to provide smart platforms to perform advanced economic modelling. For more detail see: https://project-merlin.co.uk/

1.2 Purpose

This report provides an overview of how TRANSITION is building upon cross-industry expertise to develop its commercial strategy for flexibility markets. This will include insights from existing business as usual (BaU) processes, innovation projects and academia, to provide the most complete picture of the flexibility journey required for both optimal commercial analysis and market execution of flexibility markets. The processes and outputs outlined in this contract have also been discussed and reviewed with ENW. Our outputs will feed in to ENWL's simulated trials, which can test the project's strategy before starting live trials.

A simplification of the end-to-end process covered in this report is outlined in Figure 1 below, where the colour of each box represents the section of the report it can be found in.

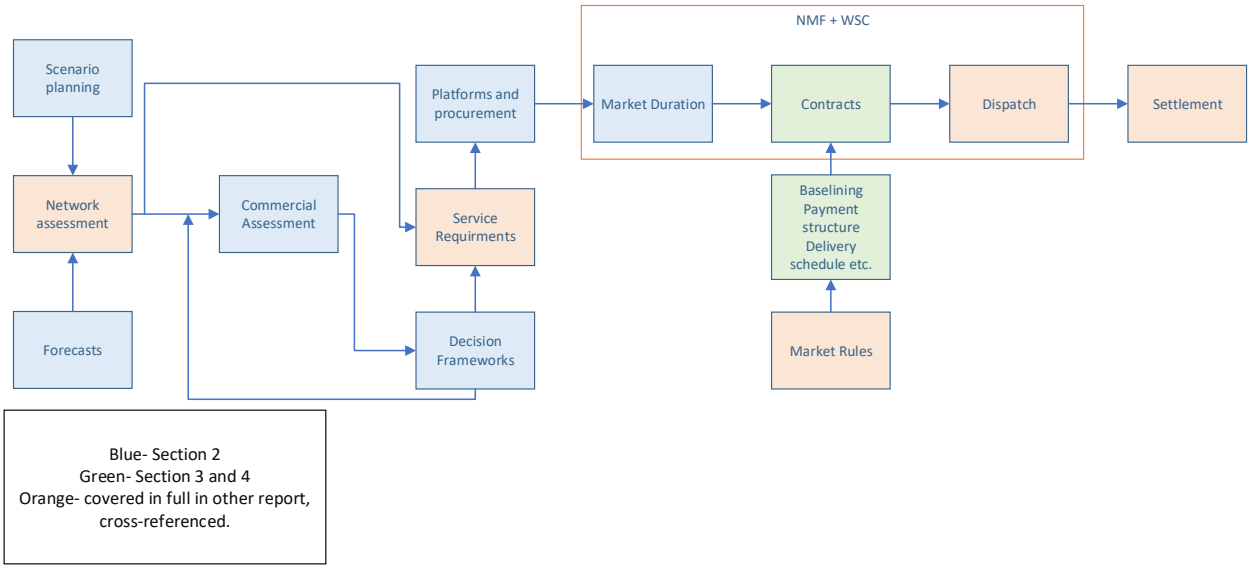

Figure 1 Report structure[5]

Alongside this analysis, the report's core output is the development of contract templates for use across TRANSITION's trials (see section 3). These templates are split into two sections, one for DSO services and one for peer-to-peer (P2P) based services.

Whilst these contracts are in a ready to use format, TRANSITION intends to continue to develop these contracts as trials progress adapting to new learning both internally and through the Electricity Networks Association (ENA) Open Networks Project (ON-P). In addition, the project will collate learning from the trials and feedback directly to the ON-P workstream (WS)1A, flexibility services.

<u>Open Networks- Approaches Across DNOs</u>

The ENA's Open Networks Project, Workstream 1A (WS1A) has fed into and will be informed by, this report. ENA WS1A looks at good practice in the procurement of Flexibility Services to

[5] Other report can be found on: https://ssen-transition.com/library/

meet DSO requirements (ENA, 2020). The 2020 Workstream boasts seven products, the outputs of which cross-over with this report are summarised in Table 1 below

Table 1 ENA ON WS1A 2020 cross-referencing

Product	Output	Report Section
1- ANM vs Reinforcement Common Methodology	Awaiting current outputs	Section 2
2- Procurement Processes	Overview of (pre-)procurement processes across DNOs	Section 2.3
3- Active Power Services Parameters	Awaiting current outputs	Section 4
4- Commercial Arrangements	Standardised contract	Section 4
5- New DSO Services	Awaiting current outputs	Section 4
6- Market Facilitation - Non DSO Services	Facilitation of New Markets Report (2019)	Section 4
7- Baselining Methodology	Awaiting current outputs	Section 3

2. Value of Flexibility

The ENA ON defines a flexibility market as: “the arena of commercial dealings between buyers and sellers of Flexibility Services.”

To model flexibility markets effectively it helps to simplify understanding by thinking of flexibility markets as a closed system with three main potential cash flow inputs. These are represented by the three bullets given in the executive summary namely: opportunity cost of generation, system balancing (BSUoS) and network operation (DUoS and TUoS).

In the same vein the economist Paul Samuelson published the first mainstream economic text book in 1948 illustrating the economy through the mechanics of taps as an input to the economy we illustrate the flows of money into flexibility markets in Figure 2 below:

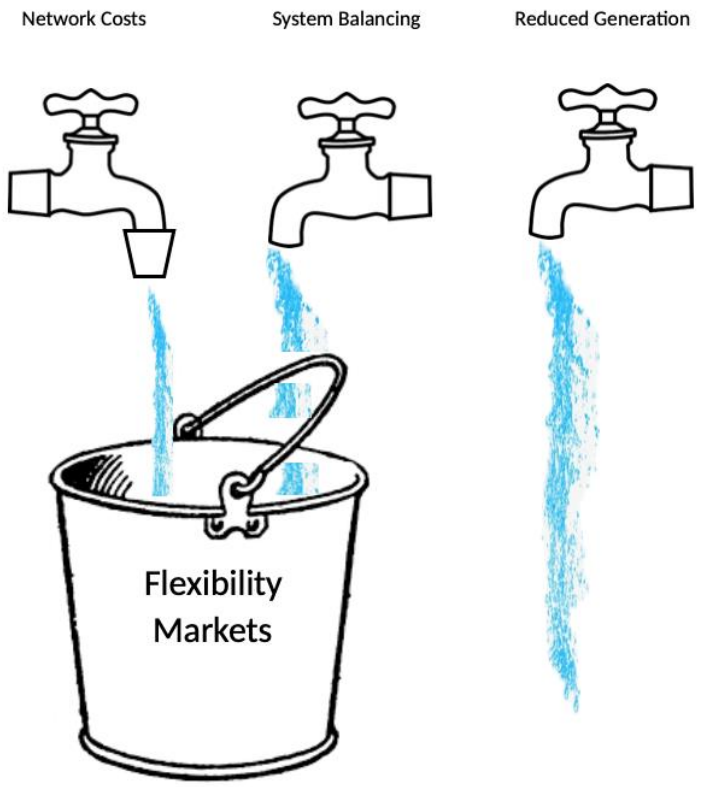

Figure 2 Whole system economic inputs

The left of Figure 2 shows the input into flexibility markets through avoided network costs, this includes revenue streams from better utilisation of assets, avoided/deferred reinforcement costs and customer interruptions (CIs)/ customer minutes lost (CMLs). The tap is illustrated as constrained by a flow restricting valve as any costs cannot account to more than the cost of traditional reinforcement solutions. System balancing is illustrated in the middle, this is paid through established competitive flexibility markets and reflected in BSUoS charges through NGESO[6]. Finally, on the right, the opportunity cost of reduced generation that can be achieved through flexibility is represented as flowing outside the bucket as this is not currently recognised within flexibility markets, potentially undervaluing their operability.

Together these inputs represent a high-level, whole system view to the value of flexibility. This report focuses on evaluating and valuing flexibility primarily through network costs. As the TRANSITION project progresses more detailed analysis will be performed on revenue stacking across the whole system and how this is represented within the project's whole system coordinator (WSC) tool.

In this section of the report we provide an overview of the trade-off being considered on TRANSITION as to how the trials will value flexibility. One school of thought indicates that the value of flexibility should be determined based upon it being more cost-effective than alternative network management solutions (i.e. traditional reinforcement). That is the DNO's Willingness to Pay (WTP). An alternative school of thought indicates whilst this may be

[6] Here balancing requirements such as frequency which are crucial for the system to operate effectively have their economic value determined by competitive free market economic mechanisms i.e. auctions.

economically efficient in the short-term the market's goal should be long-term efficiency and in order to achieve this in the short-term encouraging competition and market entry should be primary considerations. This can be done by assessing the market's Willingness-to-Accept (WTA).

These assessments may depend on:

- A number of scenarios and forecasts which are used to model uncertainty.
- Decision mechanisms
- Economic and financial models

This report will solely make reference to such work. The technical details of which frameworks will be available in a technical Evaluating Flexibility Manual (pending).

2.1 Forecasting and Scenario planning

The requirement for flexibility services is signaled by a range of different forecasting and scenario planning methodologies. These are being developed on projects outside of TRANSITION and will feed into trial operation.

Scenario planning is used to evaluate how network loading may change over long time horizons, for instance years or decades, to give an encompassing overview of how the electricity system may materialise. SSEN has worked with consultants Regen to develop Regional Future Energy Scenarios (FES) to serve this purpose and feed-in to decision frameworks.

Medium-term forecasts on the other hand may be used to asses changes in loading over the course of a (few) years, this is necessary for evaluating the amount of (flexible) capacity needed on a network over a given time-horizon and can feed into requirements around contract duration.

Short-term forecasting is used to estimate changes in load on an hourly, daily and weekly basis. This form of forecasting is used to signal requirements for activation and arming of flexibility services as well as spot-market procurement.

Analytical framework such as Least Worst Regrets (LWR) (Zachary, 2016) and Real Options Analysis (ROA) (Dawson et al., 2018) draw in these forecasting and scenario planning models to support effective decision making.

The EFFS project is developing such forecasting mechanisms. TRANSITION will continue to work closely with EFFS to feed project developments into trial design.

2.2 Commercial Assessment

The project is assessing two main mechanisms through which it may define the commercial parameters of customer payments and flexibility valuation. These can be divided into the customers' willingness-to-pay (WTP) and their willingness-to-accept (WTA). Each will be given a high-level overview below. Detailed analysis of the mechanisms will be provided in TRANSITION's valuing flexibility manual (pending).

2.2.1. Willingness-to-pay

Flexibility is currently utilised on the distribution network to provide an alternative to traditional reinforcement. This is inherently different to its use at transmission level whereby the requirement is to balance the system, a problem to which there is not an alternative solution for. As a result, in order for DNOs to ensure they are offering the most cost-effective network to customers it is their job to assess the most cost-effective way to manage the network. Traditionally this has meant placing a price ceiling on the amount a DNO would consider spending on flexibility based upon the cost of traditional reinforcement.

The DNO has several tools it can use to assess the value of flexibility against traditional reinforcement in the face of uncertainty as to how load may change over time. SSEN is working alongside Frontier Economics on a decision model, as well as with the University of Cambridge on the MERLIN (Modelling the Economic Reaction Linking Individual Networks) project to identify revenue streams which might affect the valuation put on flexibility.

By accumulating these revenue streams into a cost-benefit-analysis framework (CBA) DNOs will be able to better understand the value their networks place on flexibility and hence their willingness-to-pay (WTP) for distributed energy resource (DER) solutions. A summary of commercial and social revenue streams[7] which input into this analysis are given below:

- Net Present Value (NPV)- provides an indication of the value that can be gained from using the capital expenditure (Capex) allocated to traditional reinforcement solutions, but not spent, in other ways (i.e. the opportunity cost of spending the money).
- Option Value- accounts for the fact that flexibility buys time on decisions allowing for more accurate forecasting and potential avoidance of reinforcement. ROA provides a framework for how this may be performed. A simplified example is shown in case study one below.
- Asset life remaining- builds on NPV analysis but considers the remaining years an asset, without constraint, might be expected to last.
- Asset health- the impact of violations on asset limits may cause damage to an asset decreasing its life. Such limits are currently regulated, however on irregularly peaking networks may be an economically effective way to manage the network.
- Asset redeployment value- if an asset is replaced before the end of its life, the value of redeploying it elsewhere.
- System Losses- comparing how flexibility services can manage losses against the impact on losses of upgraded infrastructure.
- Societal disruption- through potential avoidance of civil works associated with traditional reinforcement.

[7] . In implementing or recommending any of these mechanisms for flexibility payments SSEN will follow guidance outlined by the governments 'Green Book' (2018) to apply rigorous and transparent economic analysis.

- Environmental impact- largely in CO2 reductions of utilising low carbon solutions to provide flexibility services. Care must be taken so not to double count fiscal mechanisms already applied to these markets.

Case-study one- Option Value

The below framework for calculating a value for optionality has been adapted and simplified (so not to show discounting or mathematical syntax) from: Tadelis (2013), Game Theory, p.26 backward induction.

The approach is represented through decision trees. The tree starts by representing the decision a DNO currently has to make on an asset forecasted for overload; (traditional or smart). For mathematical simplicity in this case study we assume cost of traditional reinforcement of £100 and the cost of the smart solution in this case-study being £5.

Once the initial decision has been made the decision maker then moves to node two (a period in the future say 4 years). At node two we use scenarios/forecasts to identify probability for certain levels of load-growth. For simplicity in this example we represent them as: medium, low and negative (mid, low, neg) load-growth.

In Figure 3 below you can see if you managed the network using traditional means in period 1 for any load-growth in period two there is no action required. So, your cost is simply the £100 invested in period 1. However, if you managed the network using a smart solution in period 1 your next action is dependant on the load-growth that materialises. Given the level of load-growth that materialise is period two you then pay £5 for period one + the probability of said load-scenario happening at period two multiped by the cost of managing it. For example there is a 75% chance mid load-growth will materialise in our example as a result under this node you pay the cost of smart + the cost of traditional reinforcement multiplied by its probability i.e. £5 + (100 x 0.75) = £80.

The sum of each probability that could materialise (mid, low, neg) can inform whether traditional or smart is likely to be a more cost-effective solution. In this case the expected cost of smart is £80 + £6 + £5 = £91 which is less than the cost of traditional which is £100. At this stage this has not informed optionality and has purely given a simple, non-discounted, two-period decision framework.

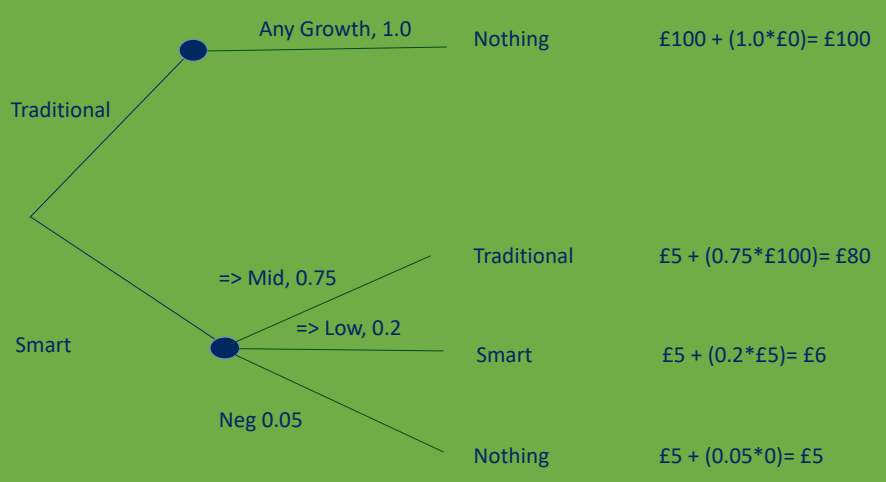

Figure 3 Decision Tree- flexibility

In order to calculate option value, we must now re-draw the decision tree as if we have a crystal ball and can see the future. For this reason, this time we draw the potential futures that could emerge first. We draw each future as we did in Figure 3 above with the same probabilities at the first decision node in **Error! Reference source not found.** below.

Decision node two in this case represents the decisions we could have made (from decision tree one) to manage this scenario and attaches a final (post node two) cost to each of them. For example if mid load-growth materialises we know from tree one that: if we use traditional in period one at cost £100 we won't have to do anything in period 2 so the total cost is £100; whereas if we choose smart in period one at a cost of £5 we will need to use traditional in period two at cost £100 with total cost of £105. This is performed for each load-growth scenario we model.

We then identify the optimal strategy for each load-growth scenario choosing the lowest cost network management option (bolded in **Error! Reference source not found.** below). These optimal strategies for each load-growth scenario are summed to give the best response functions for all load growths that could materialise. In this scenario where optimal decisions can be made the cost comes out as: (£75 + £2 + £0.25 =) £77.25.

Optionality is then worked out as the value of deferring our decision to make a better decision which is represented by: £91 - £77.25 = £13.75.

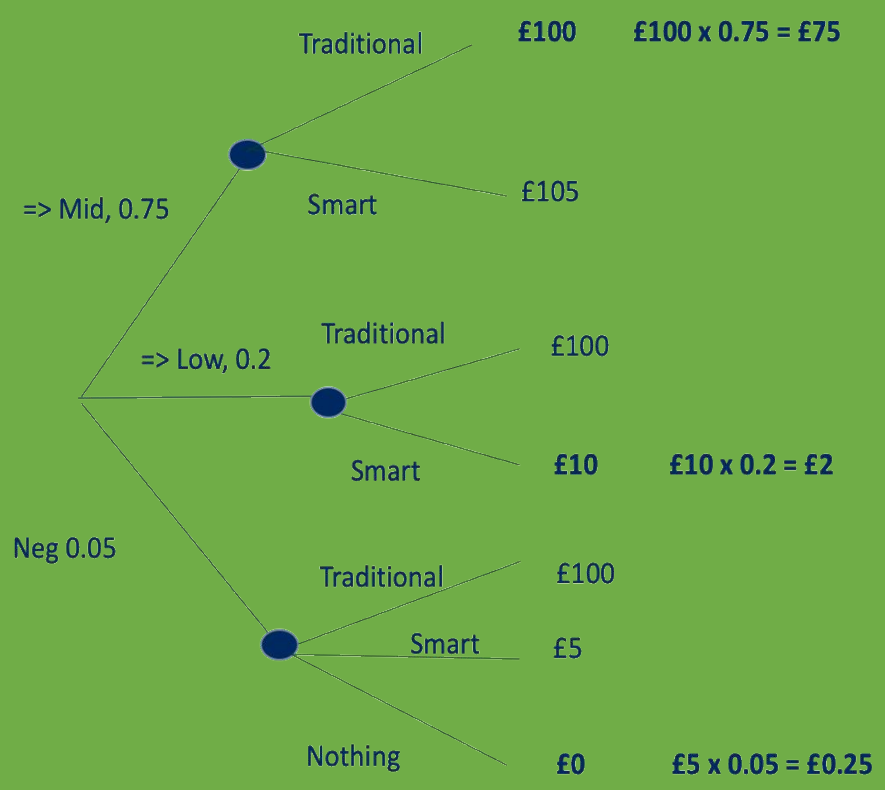

Figure 4 Reverse Decision Tree

Note- this is a heavily simplified example and real calculations should account for discounting of future costs as well as further time periods. SSEN is developing a decision-based tool with Frontier Economics through its BaU teams to feed this analysis into real network scenarios across a greater range of options/time horizons.

2.2.2. Willingness-to-accept

There is an alternative argument to say rather than looking at the flexibility market in terms of the DNO's WTP, that instead markets could be determined based on a willingness-to-accept (WTA) measure of value. WTA is commonly used in economic analysis when assessing the value of social behavior/activities that are otherwise challenging to attach monetary values to. For instance, people may be asked the minimum monetary amount they would require to accept a given change in air pollution (this may be made salient through a range of means i.e. changes in cancer rates per 1000 people) to justify a tax on emissions.

Whilst new commercial mechanisms are being explored (as above) to provide a more rigorous analytical valuation to flexibility based on a DNO's WTP; industry evidence from previous flexibility trials, indicates that DNOs have in the past struggled to procure flexibility due to commercial constraints, in particular at more community and localised areas of the network (SSEN, 2020). With this in mind assessing the WTA for suppliers might help identify the price gap between existing WTP mechanisms and the markets WTA. WTA may also be justified economically as providing a stimuli to both encourage market entry and competition resulting in lower costs over the long-run.

Within TRANSITION WTA may be assessed through two main methodologies, namely: 1) understanding of DER costs through stakeholder engagement to identify the minimum amount a DER owner might need to be paid to participate in flexibility markets; or through 2) auction mechanisms (as currently used by the ESO) to assess an efficient market equilibrium. The former of these provides a more social view to engagement and relies on truthful information share from project partners[8]. Meanwhile the latter more economic approach requires appropriate auction design for the market in question and its bidders. The analysis shaping each approach is outlined below.

Cost Discovery through stakeholder engagement

As part of the LEO project framework TRANSITION has access to a wide-array of engaged stakeholder organisations. By working with these organisations to understand existing power purchase agreements (PPAs), tariffs and operational costs that their DER units are likely to incur when participating in flexibility markets, we can build up a better understanding of market participants break-even costs.[9]

Therefore, stakeholder engagement could look to reveal the opportunity cost of assets not being able to optimise their operation and/or participating in other markets. This approach is similar to the approach taken in some ancillary markets. For instance, in Germany the Avacon demonstrator, part of the InterFLEX project, compensates providers in line with loss of production (opportunity cost).

Initial analysis has been performed on two LEO assets (as per case study two) assessing their estimated WTA against a case study of the industries existing WTP mechanisms (based on NPV only at distribution level). TRANSITION will continue to perform this type analysis to further inform WTA calculations.

[8] If DNOs were to offer payment at these levels there would be an incentive to inflate costs to maximise payment levels on the project.
[9] This does of course require 1) customers to be willing to share such commercially sensitive data and 2) rely on the trust of DER providers to not manipulate these numbers.

Case-study two- Willingness-to-accept analysis

The LEO partners have identified over 250 potential flexibility assets across Oxfordshire. This could serve as a valuable test-bed to understand the WTA of a range of different types of customer and DER asset. SSEN has performed initial analysis on two sites to understand opportunity cost of participating in flexibility markets.

This analysis was performed through the provision of data from project partners around electricity costs, payments and how these change across different timescales. The project ran three scenarios detailed below to model different ways customers may respond to flexibility markets (all markets assume flexibility is procured through long-term mechanisms and hence do not represent spot markets or other short-term markets):

1. Scenario 1: 4-8pm availability window lasting 1 season (3 months), notification period > 4 hours.
2. Scenario 2: 4-8pm availability window lasting 1 season (3 months), no notification period.
3. Scenario 3: 4-8pm availability window lasting all year, no notification period.

Costs for an asset to respond to each scenario was then modelled against current expected flexibility market costs. These costs were calculated using existing BaU methods of valuing flexibility at LV (where the asset was connected at this level) and HV (section 2.1). The project then estimated revenue streams these assets might expect if they were aggregated and also able to participate in STOR (taken from Engie 2016). STOR (Short-term operating reserve) provides a balancing reserve service to the ESO to help manage demand on the system.

The maximum payment levels an asset might expect were then represented in a stacked bar chart plotted against each asset's opportunity costs based on each scenario (green markers). This is displayed in Figure 5 below (costs are shown as total contract value).

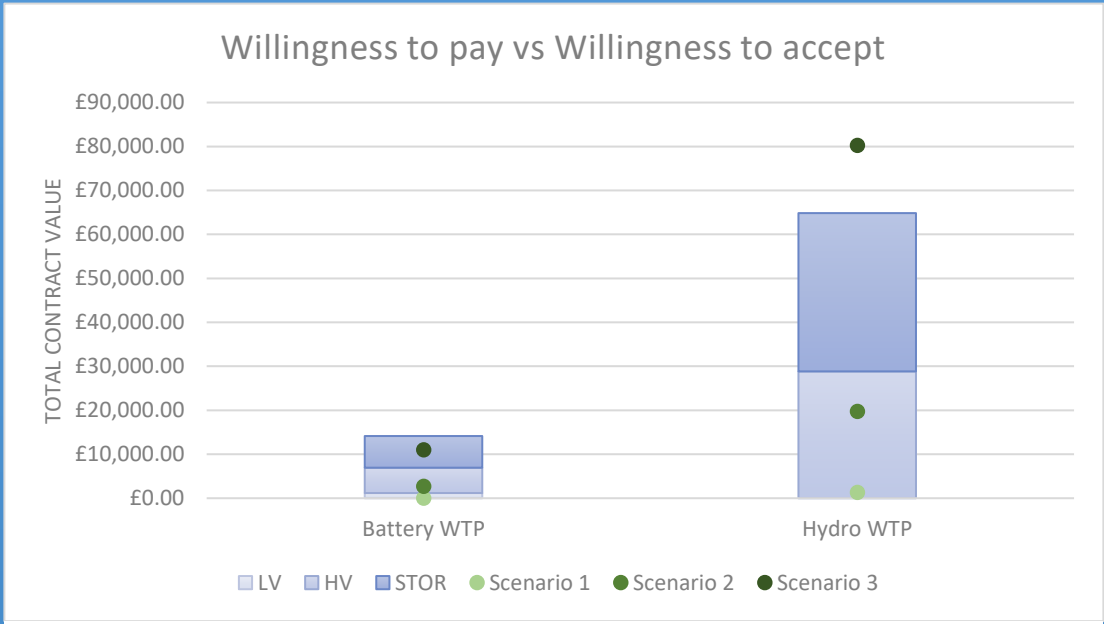

Figure 5 WTP vs WTA

The graph illustrates two main findings. First the type of flexibility market (represented by the three scenarios) can have a significant impact on opportunity costs. Markets with limited notification times will have a large impact on DER provider costs who need to be ready for an event across long-periods of time (long-term markets). This effect is likely to be greatest on forms of storage given a need to ensure they are charged/discharged as per the DNO's needs.

Second without stacking across different ancillary/flexible services DER assets may struggle to justify participation in flexible markets alone given other commercial revenue stream or high operational costs (this is before considering any Capex costs, for example if building a new asset or installing automated communications to allow for participation in some flex markets). This illustrates the value in whole system thinking to stimulate stacking across revenue streams.

2.2.2.1 Auctions

An alternative way to interpret WTA is through an auction framework. Auctions, if run appropriately, provide a marketplace for price discovery where it is difficult to establish a true value of supplying a good/service (Pollitt and Anaya, 2018).

Smart auction design will be crucial to the effective running of flexibility markets and could significantly increase the efficiency of procuring flexibility. By allowing multiple complimentary/substitute flexibility products to be procured together, such mechanisms may be beneficial in allowing a supplier of flexibility to optimise the basket of flexibility products they provide to the network.

Likewise, the network should be able to better optimise the price paid for flexibility across mechanisms, as opposed to procuring in isolation as is the current practice. This will be eased through a consolidation and simplification of flexibility mechanisms. This is something being looked into by the ESO (NG, 2017).

Auction design should not be performed naively and will benefit from drawing on expertise in auction theory and stakeholder testing to understand how individuals might interact with an auction (i.e. through a gamified lab experiments). Key things to look out for in auction design include: capabilities for collusion, repetition of auctions, complementary and substitute goods (Ausubel and Cramton, 2011), predatory pricing, market maturity and complexity to execute (Pollitt and Anaya, 2018).

Economic analyses around auction frameworks illustrate a requirement to understand the market in question, its participants and its objectives. There is a wealth of evidence in effective auction design through both the ESO and across academia in other large auction markets (i.e. bonds, Wang and Zender, 2002, radio spectrum; Milgrom, 2000 and wind rights, Ausubel and Cramton, 2011). Understanding of the market in question will build from the work done on UKPN's Power Potential project and WPD's ENTIRE.

Power Potential

In order to maximise overall welfare and better reflect the system's needs for reactive power, Power Potentials auction was designed for day-ahead procurement. To make this

process manageable a Distributed Energy Resources Management System (DERMS) was used to support technical and commercial optimisation of dispatch on Power Potential (NGESO, 2020). Within this portal participants indicate availability prices (£/Mvarh/hr) and utilisation prices (£/Mvarh) for reactive power (exclusive to wave 2 of the trial, wave 1 was a market determined availability only payment) and if successful are paid at pay-as-bid.

The Power Potential auction is designed to remove barriers to entry for new market participants (who are initially higher cost). This is done by NGESO accepting bids for services that cost more than flexible assets on the transmission network. However, a price ceiling is determined by the cost of resolving constraints through network reinforcement, any assets bidding above this level will be rejected (NG and UKPN, 2020). This is justified by expectations on lower costs in the long-run through greater competition.

Services are planned to be contracted by service windows, these varied from half-hourly to every four hours across different waves of engagement (NGESO, 2020) and started in spring 2020.

ENTIRE and Flexible Power

WPD operate their flexibility markets through an innovative design made up of three phases. They award contracts on an annual basis (that becoming rolling after the first year[10]). Where initial procurement does not find sufficient flexibility to provide a competitive market, they pay a fixed price of £300/MWh. Where there is sufficient competition they pay a pay-as-clear mechanisms (details on how this is calculated can be found at: https://www.flexiblepower.co.uk/tools-and-documents, under: 'Clearing Process').

Theoretically this process will increase transparency of the market as flexibility providers will be encouraged to bid at their true cost. However, as mechanisms (which are built off of second-price sealed-bid auctions) may be more susceptible to collusion (Nicolaisen et al. 2001). This should be managed through appropriate regulation at higher network levels with larger assets, however this could be difficult to monitor if used at lower network levels for instance across neighborhoods of domestic customers.

Prices are submitted to WPD as total price for a MWh regardless of availability, arming or utilisation. Percentage splits are then pre-determined towards each service. Longer-term planning then indicates that as the markets mature contract lengths will shorten, building fluidity into the market (WPD, 2020)

ENA ON-P

Procurement and auctioning of flexibility is also currently being assessed by ON WS1A P2. Open Networks has produced a rigorous overview of how flexibility may be procured including: signposting of future requirements, identifying and communicating current requirements, assessing the market, registering interest, pre-qualification and operation of flexibility and non-flexibility services. Full details can be found at: https://www.energynetworks.org/assets/files/ON-WS1A-

[10] This will feed in to contract considerations in section xx

P2%20DSOServices_ProcurementProcesses_Consultation_Final_2July%20v1.0%20(Published).pdf

The ON-P is continuing to make progress in advancing the auction mechanisms which define the procurement of different flexibility services and currently recommends: *"Auctions require more standardisation, making the process more transparent and simplified. However, over-simplification then also limits the scope for customising offerings, creating potential challenges to those wanting to enter the market. Those DNOs seeking to use auctions to procure should continue to find the right balance between making the process simple enough for providers to participate in and allowing some flexibility in the service provision to encourage market uptake"* (ENA, 2019b).

TRANSITION, working with the University of Oxford is in the process of designing auction mechanisms it could trial on the project. Given the project provides a simplified testbed for whole system co-ordination (by trialing 2 DSO products and 1 ESO product, detailed in section 4) a heterogenous multi-unit auction could be designed to procure services and settle contract values (either as a game or for the actual project trials).

Initial considerations for such procurement auctions and how contracts will remain flexible to accommodate procurement criteria are captured in section 4.1.2. In September 2020 the project will publish a paper exploring applications of behavioral economics to smart auction design. Outputs will be fed into the ON-P and support in the learning developed as a part of WS1A P2.

2.2.3 Summary and Other considerations

The above WTP and WTA mechanisms can be used to inform the prices flexibility is procured for. On TRANSITION it is likely that no mechanisms will be used in isolation, the project will likely draw on all approaches outlined to define a value for flexibility. For example, initial WTA analysis based on stakeholder engagement may define auction parameters, however an auction itself could be used to settle the market and tease out efficient equilibriums. This should be compared with WTP analysis in order to determine any gap in WTP and WTA. Such a gap is useful in indicating how far the market would have to develop to run cost-effectively when compared to traditional (i.e. engineering) based solutions.

Market prices can also be translated in different ways through varied procurement mechanisms/payment structures. Most common across flexibility markets are pay-as-bid, pay-as-clear (currently used by WPD, 2020), or a form of regulated price (i.e. a fixed price per MWh). The method deemed most appropriate depends on a range of factors including market maturity, market aims and regulatory requirements and again feeds into auction design considerations.

Next, the structure of payments to users will need to be detailed. This will tend to be represented as some form of split between availability and utilisation (and sometimes arming) payments. Currently different DNOs offer different splits between availability and utilistaion across services based on the service requirements.

The current stance in TRANSITION is that payment should be technology agnostic as certain payment mechanisms may benefit certain types of asset and company over others. Resultantly, flexibility should be awarded based on overall contract value and then suppliers

given their own means of weighting between availability and utilisation payments[11]. The DNO will then inform what these payment amounts equate to, based on their own estimation of how many utilisations are expected per period in question (i.e. year).

SSEN's BaU teams are currently working with Frontier Economics who will provide a model to support pricing structures including an assessment of willingness-to-pay vs willingness-to-accept. TRANSITION will feed-in and draw-from this work to efficiently progress industry development.

Risk Analysis

Future work in this area might also focus more attention on risk analysis to help optimise the amount and types of flexibility procured. Probabilistic analytical approaches can be used to inform reliability of forecasts as well as of DER delivering their contracted response. For instance, one asset might be very reliable in delivering 100kWh, always delivering between 99kWh and 101kWh of demand response (low variance) whilst another asset might also average a demand reduction of 100kWh but deliver between 50kWh and 150kWh from event-to-event. DNOs need to understand this and have a means to quantify this within their margins when procuring flexibility.

Likewise, it might be that the more a DNO procures varied amount DER the more it spreads risk of flexibility under-delivering. Take for instance a DNO that is procuring DER through commercial demand response. This might be effective 90% of the time, however if these demand response capabilities are mainly made up of turning off/down cooling load on a particularly cold day there may be less demand response than usual. Whilst this shouldn't be a problem if the DNO procures from a variety of DER assets, it will be a problem if the DNO's entire market is run on the same source of commercial DER which suddenly becomes unavailable/less responsive. Much like investors diversify risk across stocks and shares DNOs may wish to use similar analysis in diversifying risk across assets.

Project partners on LEO, The University of Oxford, are currently looking at analysing the probability distributions of different assets to start informing this sort of analysis.

Future Considerations

In the future DNOs and government may also want to consider both: incentives on DNOs to invest in flexibility given impacts on Totex and should some of the more aggressive load-growth scenarios look to materialise, approaches to value in phasing reinforcement works so to effectively 'flatten the curve' of network reinforcement needed to accommodate a zero carbon economy (i.e. both social and monetary cost of doing all reinforcements in a short time span may be greater than phasing this over longer time horizons).

[11] Some parameters may still need to be put in place to limit the amount a supplier can weight availability/utilisation/arming to ensure the market still provides appropriate signals.

3. Baselining Methodology

Baselining provides a mechanism for determining the impact of flexibility event or trade. Appropriate baselining methodologies are important for both the network and DER providers as this effectively determines how well a customer has responded and hence how much they will be paid. An appropriate baselining mechanism will give the market confidence that reliable DER solutions will be paid accordingly and fairly. Baselining methodologies should also mitigate abilities to game the market (i.e. manipulate load-profiles to make load-sheds look larger). Data science, statistics and probabilistic modelling techniques are feeding into the industries baselining methodologies through the ON WS1A P6. At time of writing there is no output from this work package, TRANSITION is and will continue to feed into this area.

3.1 Baseline overview

When considering a baselining methodology, it is important to acknowledge that baselining may not be a 'one-size-fits-all' solution. Different methodologies may carry different merits based on how and for what purpose they are deployed. For instance, factors such as the variability of consumption profiles, timescales, the granularity of data and the settlement mechanisms that baselining will inform should all be considered.

The baselining methodology developed on the ENTIRE project is published on the flexible power programme website. Their methodology signals the need for different approaches to baselining across generation sites (which may be more variable) and demand response sites. The basic approach to baselining takes the average of the first three weeks of full data. They then look at the 3pm to 8pm time-stamped data specifically and take an average to determine a baseline. Whilst they acknowledge this approach will work for demand side mechanisms where the approach divides, is that for generators if data is erratic it may be that forecasted output is zero.

This approach provides an important distinction that baselining mechanisms that work very well for one site may be very inappropriate for another site. Whilst ENTIRE's approach to this appears to be mainly associated with generation sites, SSEN's experience from the Solent Achieving Value through Efficiency (SAVE) project (domestic DSR) and New Thames Valley Vision (NTVV; including testing of SME DSR) highlight how a range of different DER sources may be variable in their consumption. As a result, it is felt this distinction should be given a higher level of statistical rigour. Whereby sites with variability within a certain level, x, use method 1, and above a certain level, y, use method 2 for instance (this does of course also bring into question how variability is measured and over what time intervals).

Within TRANSITION the project has begun exploring two distinct baselining methodologies for assets with both 'predictable' and 'unpredictable' baseline demand. This is slightly differentiated to current ON-P thinking which is looking at different baselining methods that may be needed for different technology types. This will ensure baselining is technology agnostic between different forms of DER, however does not account for the variance within types of DER. As a result, the project team sees merit in analysing baselining based on load-profile variability as an alternate means. We will share learnings with ON as methods continue to develop.

3.2 Predictable

Numerous early innovation projects explored different baselining methodologies (Low Carbon London, Customer Led Network Revolution, New Thames Valley Vision- NTVV). One output of the NTVV project was an extensive international review from over 20 sources[12] (including other longitudinal studies). This approach was developed using support from partners on the European DISCERN project as well as on studies from across North America.

The approach (taken from the NTVV Technical Guide Capacity Document) takes a day comparison approach, using day matching to establish the days to be used to derive the baseline.

The 22-hour period starting at 2am is used for performance assessment (this provides clarity in the event that a DSR event day coincides with a clock change and allows for days to be considered on a clock consistent basis i.e. so that 4pm GMT is aligned to 4pm BST). The prior 10 eligible days[13] (5 days for weekends) are assessed and the 6 days (3 days for weekends) with total electricity demand most closely matching the total daily electricity consumption (kWh) on the event day (excluding the capacity response event period) will be used to derive the baseline.

The eligible days are averaged using minute-by-minute interval meter data[14] to produce an unadjusted baseline. This baseline is then adjusted as a refinement to align the baseline to the DSR event day. The adjustment process is derived from the interval meter readings for the 4 hours prior to the DSR event. The differences between each of the minute-by-minute readings are averaged to generate an additive adjustment.

The load-profile across the DSR event day is then compared to the baseline demand, compared with the suppliers' contracted capacity and will be paid as per their contract terms.

In order to utilise this process SSEN will gather data for the event days itself and a previous month's worth of data to calculate the baseline from (this accounts for potential for errors in data recording and for the 3 weeks + needed if a weekend event is being baselined).

Mathematical syntax used for calculating the above baseline process is reserved for Appendix 2.

3.3 Unpredictable

Perhaps the most salient examples of erratic or unpredictable DER come from domestic demand side response. This is something that is well acknowledged within network planning, whereby After Diversity Maximum Demand (ADMD) methodologies are used to

[12] Outlined in Appendix 1

[13] For weekdays eligible days are defined as: those that are not: 1) weekends, 2) bank holidays, 3) other DSR event days; 4) days for which the DSR service was declared unavailable.
For Saturdays eligible days are previous Saturdays that were not: 1)DSR event days, 2) days for which the DSR service was declared unavailable.
For Sundays eligible days are previous Sundays that were not: 1) DSR event days, 2) days for which the DSR service was declared unavailable.

[14] This would be adjusted to the most granular time interval available for TRANSITION trials

model the network based on the number of aggregated customers. The effect is generally more pronounced for smaller amounts of customer where the chances of multiple peaks in demand coinciding is greater. Effectively more customers starts' to 'smooth' the baseline. This will become particularly important when considering flexibility on lower voltage networks with fewer total customers and higher proportions of domestic/SME customers than seen at higher voltages.

SSEN has a wealth of knowledge on the load-profiles of domestic customers and how they might vary both across types of household and types of intervention (i.e. demand reduction) from the SAVE project.

SAVE highlighted that even with large samples of domestic customer (up to 1000) domestic demand-side response can still be challenging to detect with statistical significance. Various forms of analysis were used on the project including weather adjustments, difference-in-difference analysis (SSEN, 2019) and by looking at data over a variety of timescales.

One interesting use of statistics suggested as an output on SAVE is the use of Bayesian statistics to support in determining the amount of load-shed by a small/erratic customer. Bayesian statistics take an estimate of the amount load-reduction expected ('prior beliefs') into account before performing further analysis. The theorem combines these expected values with the actual data to mathematically approximate a value which balances both what you saw and what you expected. This is particularly helpful when analysing small datasets/numbers of customer (TNEI, 2020). This sort of statistical modelling is supported greatly through more data to better inform 'prior' estimates and provides a case (amongst others) for the availability of open source data in flexibility markets.

Further modelling is required to develop this approach, further insight into the statistics and modelling will be found in TNEI's forthcoming Cigre report.

3.4 Monitor Granularity

A final key consideration in designing a baselining methodology is the granularity of data required for that baseline. Current ENA outputs from WS1A (flexibility services) indicate a preference for minute-by-minute granularity (see contracts in section 4). Whilst more granular data is largely better in determining more accurately how much has been load-shed, such granularity may also pose a barrier to entry for some DER providers. For instance, many sites will likely be ready fitted with half-hourly monitoring of some sort (including domestic properties with smart meters) a requirement to retrofit such sites with more granular monitoring could be expensive and particularly unattractive to smaller market entrants such as SME's and community groups.

Monitoring granularity is also an important consideration for settlement methodologies. Some settlement methodologies simply pay based on delivering a defined kW/kWh amount over a service window. This can have the problem of over-under procurement across an events time window (i.e. a DER unit may deliver 150% of contracted service requirements in the first 30 mins of an event and only 50% in the second 30 mins. As a result it would average 100% delivery across the hour but may not have delivered what was required for the network in question).

The ENTIRE project tackled this issue with the introduction of a multi-level settlement mechanism. The first mechanism looked at what was being delivered by a DER unit on a minute-by-minute basis and paid based on consumption being within a set percentage of contracted DSR across each minute. The second mechanism also provides a volume measurement.

Drawing on the above learning the TRANSITION project acknowledges that the actual level of data granularity is an important consideration to be taken on a service-by-service basis and potentially as the market matures. For initial trials on TRANSITION monitoring requirements will be relaxed to half-hourly requirements to minimise barriers to market and as we acknowledge that most services will be of longer durations and hence less reliant on more granular data. For settlement we will look into drawing upon the ENTIRE approach to both a 'within event' time metric for success and a final volume measurement. Unlike the ENTRIE project no penalties will be issued alongside these mechanisms as per ENA guidance (ENA, 2019)

4. Commercial Contracts

4.1 Flexibility Services

TRANSITION's 'Services in Facilitated a Market' report outlines five flexibility services that were designed and selected by SSEN and Origami Energy. These services can be split into two distinct categories: Network Management (DSO Constraint Management, Peak Management and STOR) and Energy Exchange services (Offsetting and Authorised Supply Capacity Training). TRANSITION plans to run these services in parallel and explore conflicts of interest between each type of agreement. For the purposes of the templates outlined in this report we will keep both sets of service mutually exclusive.

4.1.1 DSO Services

Three DSO services were designed for trial within TRANSITION with the aim to: act as potential future DSO services, build on preceding projects (Power Potential, and ENTIRE) and demonstrate whole system co-ordination. Each of the services selected is summarised in TRANSITION's: 'Services in a Facilitated Market' report (2019).

Since the publication of TRANSITION's services in a facilitated market report the ON, WS1A, 2019 P2 (DSO Services) completed a piece of work to standardise terminology across the DNOs when it comes to defining services (ENA, 2019d). As such the below service names are now being adopted throughout the industry:

- **Sustain**- Scheduled Constraint Management
- **Secure**- Pre-Fault Constraint (Manual and Automatic)
- **Dynamic**- Post-Fault Constraint Management
- **Restore**- Restoration Support

In order to align TRANSITION with the wider industry and provide consistency for stakeholders the project has aligned its services definitions with the outputs of ON.

A short overview of the TRANSITION services is provided below:

1. **Dynamic - Constraint Management (DCM)**; definition: The delivery of flexibility during a fault following an outage which involves the loss of a critical asset that puts the local network at risk and requires the immediate delivery of flexibility.

2. **Sustain- Peak Management (SPM)**; purpose: The delivery of flexibility to cater for the forecast overload where a planned delivery of flexibility is required. Peak management can be provided through both active and reactive power services.[15]

3. **Short-Term Operating Reserve (STOR)**; "To provide the ESO with access to sources of extra power to help manage the system when actual demand on the system is greater than forecast or there is an unforeseen generation unavailability which occurs more often than previously due to the imbalances caused by the growth of intermittent wind and solar generation. This is an ESO scheduled service." (TRANSITION, 2019, p.35);

4.1.2 Flexibility Service Procurement

Section 2.2 of the report provided a generic introduction to flexibility procurement, industry best practice and auction theory. Each of TRANSITION's markets will be markedly different based upon both the service required and the market maturity. As a result, a range of different payment mechanisms must be reflected in both auction approaches and then in contracts.

Key considerations for DCM and SPM services include:

-DCM services will be required to be available at limited notice. As a result, availability windows will likely be indicated at contract initiation at which point customers are expected to be available to respond throughout that window at short notice. To ensure security of supply whilst markets are immature may necessitate a need for availability payments to keep customers available. In mature markets however probabilistic risk profiling should support moving towards more of a short-term market based more on utilisation payment.

-Given DCM's requirement for fast response to outages, pre-procurement weightings may also prioritise faster responding assets over slower response. This however will not preclude slow response assets from participating in immature markets so long as the DNO has confidence in its ability to retain security of supply.

- SPM markets may be based on more short and medium-term forecasting (i.e. day and week-ahead) to manage potential overload. As a result, whilst these markets, much like STOR, may offer participants the opportunity to either participate in upfront long-term (committed) services or week-ahead based (flexible services). In the latter DER may be paid for arming their service across defined service windows and utilisation if called upon.

-Given the potential overlap of services across network voltage levels, SPM markets, which will be procured over the short-term, may choose to run their markets on different

[15] Through allowing Sustain- Peak Management to be manged through both active and reactive power services TRANSITION will trial how effective reactive power can be in managing distribution network issues. DER providers will need to be able to provide and monitor MVAR, these requirements and payment scales will then be fed into the same schedule templates of the contract as outlined in section 4.4.

days of the week allowing customers to optimise the market they choose to participate in. This will be arranged around the STOR market which currently procures on a Thursday.

An illustrative overview of how this approach may look over services, effect payment mechanisms and feed into contracts is given in Figure 6.

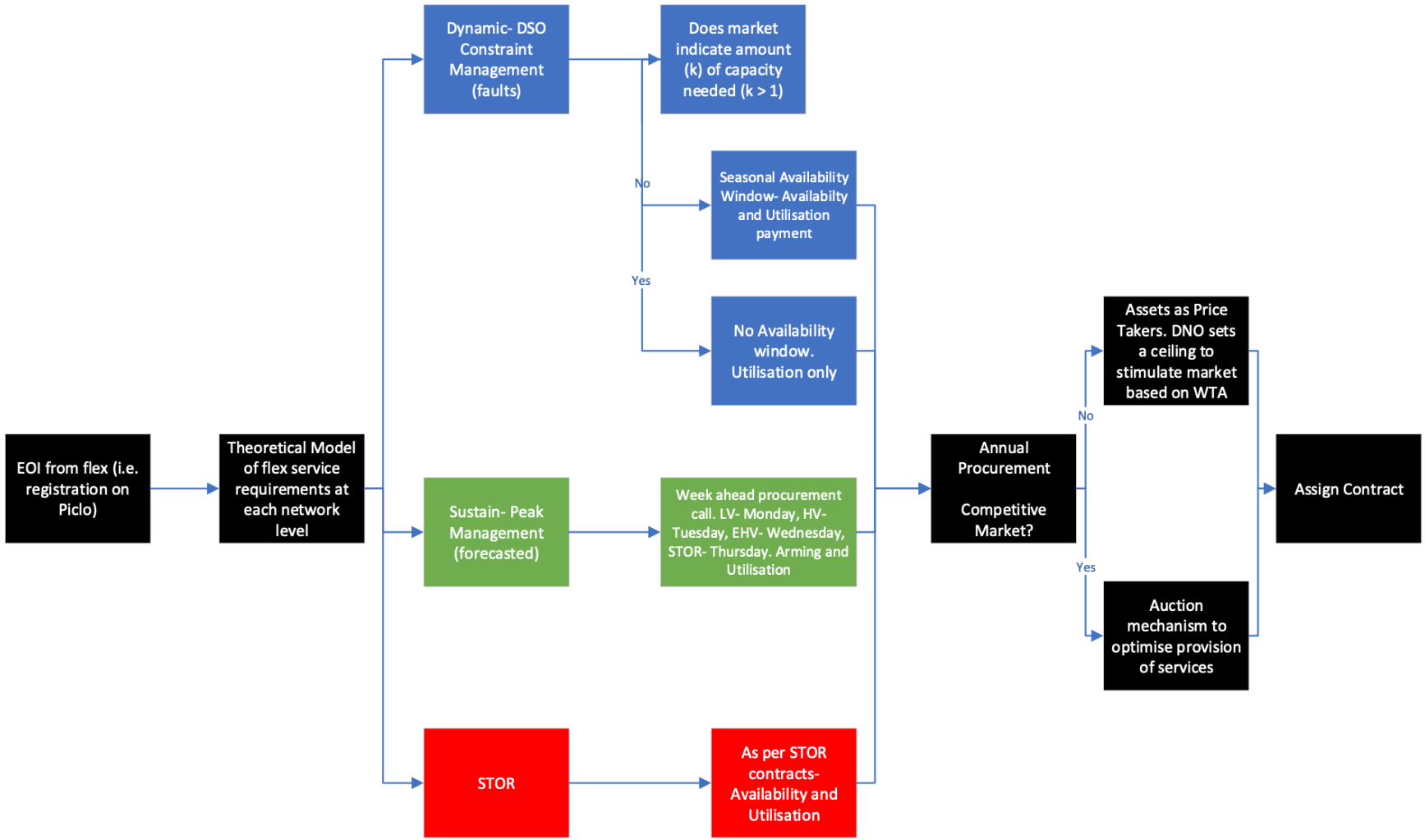

Figure 6 Service Structure and Procurement

4.2 Building a contract

The contracts built for TRANSITION were developed based on industry best practice learning and then tailored for the project's specific design. This included a cross-tabulation exercise of existing contracts against TRANSITION's trials, followed by extensive stakeholder engagement with project LEO partners to ensure contracts were accessible and minimised barriers to entry. In order to further stimulate the market in LEO the project team used insights from behavioral economics to create a choice architecture that was as simple, structured and as flexible as possible whilst still meeting DSO, legal and regulatory requirements.

A primary consideration in contract design was the capability for assets to run across multiple, sometimes conflicting services. At present this is seen as a considerable barrier to market, given the chances or instances of services conflicting may be relatively slim. For instance, take a DNO which procures services over the 90-day winter period, over this time it anticipates seven events whereby it will have to call on an asset. Likewise, at Transmission level, the ESO also requires a service across the whole year which it anticipates will call on 25 times. Therefore, on any given day the chances of Transmission calling on a service are 14.6% and the chance of a DNO calling on that service are 12.9%, therefore the probability of both assets being called upon in the year in question are: (7 x (0.146 x 0.129) =) 13.2%. This means that for a 13.2% chance of one conflict in service that asset is being precluded from participating in both services (illustrative only).

TRANSITION will test service stacking and provide an approach to how it may be managed contractually and economically. The methodology being suggested for this is expanded on in schedule six of the contract.

4.2.1 Open Networks Contract design

Starting January 2019, the ENA ON WS1A P4 began work on a 12-month programme to review and develop service agreements and contracts utilised by DSOs when procuring flexibility services (ENA, 2019). The final output provided a uniform contract[16] for DSOs to use across the four currently procured (BaU) DNO flexibility services, namely: sustain, dynamic, secure and restore.

The development of these contracts has drawn on agreements from UKPN, WPD, SSEN, ENWL, SPEN and NPG. Legal expertise, product team expertise and stakeholder feedback each fed in to the ENA to develop the contract. Some headline benefits of such an approach include: universally applied terms, unified roles of different actors, pre-released and web-based example agreements to allow DER providers to review and contentious term pre-procurement (ENA, 2019).

[16] available at: https://www.energynetworks.org/assets/files/electricity/futures/Open_Networks/ONP-WS1A%20-%20Standard%20Flexibility%20Services%20Agreement%20-%20Final%20V1.1%20PUBLISHED.pdf

For this reason, it was deemed the ON-P template would perform an appropriate base for the TRANSITION flexible services. TRANSITION will feed its contract amendments back to ON-P to support future contract iterations.

4.2.2 Other Contracts

Given the design of TRANSITION's peak reactive and STOR services the project was able to build upon a significant amount of industry learning from existing markets and other projects within its contract design. Namely including the Power Potential project (UKPN) for the Sustain- Peak Management trials and National Grid's existing STOR contracts. See below for further details.

4.2.2.1 Power Potential

The Power Potential contract covers largely the same elements as the Open Networks contract. The project team felt the open networks contract was easier to navigate and provided a smarter schedule layout for facilitating multiple services as TRANSITION will test. Power Potential did have a rigorous section on asset testing and test schedules which can support requirements set by TRANSITION.

4.2.2.2 STOR

The STOR contracts shows clear differences to the ON contract signaling a significantly more developed market. The extensive nature of the contract was highlighted as a potential barrier for small and lower value market DER. Given TRANSITION's aim to understand conflicts of interest and to encourage a variety of types and scales of DER to market the level of rigor within the STOR contract was not deemed necessary for TRANSITION.

Nevertheless, the project acknowledges the need for the DNO market to integrate and understand the ESO ancillary services market in order to optimise market design and so has captured content around for the scheduling of contracts and flexibility services.

4.3 Contract Coding

A key consideration in the contract design was making the contract as simple as possible so not to act as a barrier for entry to smaller DER participants. As a result, TRANSITION will continue to develop and refine its contractual architecture as the project progresses and develops new learning.

One such area of progression will come alongside the ongoing development of the market rules. As this develops the project team will assess the capability to remove generic contract terms that can be reflected in market rules or on a universally accessible webpage as opposed to legal templates.

The second key consideration was how to mitigate against the potential for excessive amounts of contracts across: services, network levels and different assets owned by a single customer. Without appropriate contract management infrastructure there is the potential for an unwieldy number of contracts for both DNOs and customers.

This will be supported by tools such as the flexible power portal developed out of the ENTIRE project but also requires a smart framework to base agreements from.

Building on evidence from section 4.1 and 4.2, stakeholder engagement with LEO project participants and behavioral insights the project looks to address this through a coded system. This simplified coding will also provide flexibility when integrating contracts with TRANSITION's NMF.

All network levels an asset is connected to will be divided by a simple decimal system whereby each GSP (Grid Supply Point) connected to the national network is represented by a numeric vector: 1, 2… N. Each BSP (Bulk Supply Point) connected to any given GSP is also a numeric vector: 1, 2… N; each secondary substation connected to a given primary substation is also a numeric vector: 1, 2… N; and each secondary substation connected to a given primary substation is also a numeric vector: 1, 2… N.

To signal whether an asset is providing a service or not at a given network level then each service will be lettered a – z and attached to the appropriate node of the network it relates to. This is best represented in Table 2 below.

Table 2 Service stack coding

	National Grid	GSP (400kV – 132kV)	BSP (132kV – 33kV)	Primary Substation (33kV- 11kV)	Secondary Substation (11kV – 400V)
Dynamic- DSO Constraint Management (a)	NA	1.1a	1.1.1a	1.1.1.1a	1.1.1.1.1a
Sustain- Peak Management (b)	NA	1.1b	1.1.1b	1.1.1.1b	1.1.1.1.1b
STOR (c)	1c	NA	NA	NA	NA

Each network level is represented by a decreasing decimal system as you move towards lower voltages. For instance, a DER providing a service just to National Grid might be coded: 1c. The same DER providing a service to National Grid and a given GSP (say GSP 2) would be coded: 1c. 2a. A service provided to National Grid and a given GSP (say GSP 2) and the first primary substation on the first BSP to that GSP it would be coded: 1c.2a..1.1b. If a service was only provided at the primary substation (connected to GSP 2) it would be coded: 1.2.1.1b. If multiple services were provided at one site (say the GSP serving the primary substation above) it would be coded: 1.2ab.1.1b

Whilst this coded system at first requires a shift in thinking it allows clear mapping of multiple services onto a single contract regardless of geography or service type.

4.4 TRANSITION Contract

The below section provides an overview of the key changes made to the Open Networks contract template. Changes have been built upon to provide a more flexible framework to test TRANSITION's learning objectives and to provide a more whole system view on flexibility. All changes have built upon stakeholder feedback from partners on project LEO and are indicated through *italics*.

A refined version of the contract itself will be made available upon request. TRANSITION's intention is to test the ON-P template with the below changes across its trials and feedback learning. The TRANSITION contract will be iterated where appropriate during the lifecycle of the project as learning and feedback come out of both trials and ON-P.

The TRANSITION project team support the notion of a generic flexibility contract across DNOs and even in time with the SO. However, the project acknowledges that creating a contract that is generic may not be economically efficient for differing market actors and market structures. For instance, domestic and SME customers may need different terms to that of large multinationals; likewise a monopolised market may need different protections to that of a competitive market due to the market power and resultant network risk the former could exert.

1. Definitions

Terms to be added:

Arming: Placing a flexible asset in detection mode for triggered flexibility services to ensure immediate dispatch

Maximum Ramping Period: The maximum allowed time, once a Utilisation Instruction has been issued or becomes active, for a Flexibility Provider to reach their Contracted Flexible Capacity.

Ramp-down Duration: The duration (measured in minutes) the flexibility asset (or pool of flexibility assets) take(s) to change output (demand or generation) from the instructed output to normal operating output at the end of service delivery.

Ramp-up Duration: The duration (measured in minutes) the flexibility asset (or pool of flexibility assets) take(s) to change output (demand or generation) from the normal operating output to the instructed output at the start of service delivery.

Service Failure: A service may be deemed to have failed in its delivery should it: fail to deliver on time, fail to deliver to the contracted level, fail to deliver for the contracted duration or fail to deliver at all.

A recommendation for future work through the ENA might look to amalgamate contract terms with the ESO to provide greater consistency for customers.

2. Duration of term

Updated to reflect reference to multiple services in Schedule 1. This is because each flexibility service may be subject to different contractual durations.

The termination of each service is defined as per Schedule 1. The contracts term will continue until the end of the longest contracted service.

3. Scope of flexibility services

3.7 noted the requirements on a provider to respond (whether available or not) to an instruction in accordance with their service (schedule 4). This reflects the supplier's requirement to respond with availability for planned services such as Sustain but is not reflective of Secure/Dynamic services where availability is expected, unless the DSO is otherwise notified upfront of a justifiable reason why not. As a result, this clause is deemed not suitable for multiple services and has been updated (alongside schedule 4) with the addition:

withdrawal from certain flexibility services may incur reduced payments in accordance with ***Error! Reference source not found.***.

The TRANSITION services in facilitated markets report has highlighted the consideration of ramp periods. To ensure that the DNO gets the level of response required across a given service window ramping up and down will be required outside of these service windows (unless otherwise specified i.e. for fast response events). Likewise, in consistency with the ESO (NGESO, 2013) availability payments will not only cover delivery windows (excluding ramp periods), however utilisation will pay for energy used during ramp-up and ramp-down this is addressed through the following clause addition:

3.8 Unless otherwise specified, ramp-up/ramp-down periods must take place outside of a provider's service window.

3.8.1 Availability payments will only be paid across a customer's service window

3.8.2 Utilisation payments will be made for the amount of contracted energy (MWh) delivered across an event. This will include the service window and related ramp-periods.

Amendment: 3.10- No Utilisation Fees shall be due to the Provider by the Company for any Flexibility Services delivered in excess of the accepted [MW/MVAR] *unless specifically requested by the DNO.*

4. Variation

4.2 notes how, with the companies' approval, the provider may change the DER providing the service.

Addition: 4.21- *Approval will be based on the DNO's two-dimensional risk matrix which assigns probabilities of delivery based on asset test results17.*

Recommendation that 4.3 Variation to Service Windows becomes a Market Rule and is removed from contract.

[17] Working with LEO Project partners at the University of Oxford the project will look to understand risks of different technologies based on the reliability of their responses (distribution curves). This work is still pending so has not been formally added to the contract template in Appendix 3.

5. Discretionary flexibility services

Discretionary flexibility services include reference to any other services the provider may be party to as well as arrangements around asks for over-procurement. This is particularly relevant to this agreement on TRANSITION as the project will (where required) be stacking flexibility services within one contract.

Amendment: 5.6- In performing the Discretionary Flexibility Services pursuant to this agreement, the provider must comply with the technical requirements *and prioritisation procedure* set out in schedule 6.

6. Monitoring and Equipment

Clause 6.1 specifies the use of minute-by-minute metering, within TRANSITION we will also consider 30-minute metering. This would not be recommended for current business as usual practice, however within the project this will both reduce entry barriers and understand whether services require such a granular means of monitoring granularity. It is anticipated this may be revisited and more stringent monitoring parameters may evolve as the project progresses and further interacts with DER providers.

7. Records and Audit

No intended changes.

8. Insurance

No intended changes.

9. Providers Obligations

Addition: *9.1.7.1- Prioritisation of potential conflicts in services covered by this agreement is covered in schedule 6.*

10. Representations and Warranties

No intended changes.

11. Charges and payments

Removal of term: 11.2- The Charges shall be calculated by the provider in accordance with schedule 2.

Replaced 11.2 with- *The Charges shall be calculated by the Company in accordance with schedule 2. A summary statement will be sent to the Provider every 180 days, setting out in*

respect of the DER Unit and for each Settlement Period in which it provided the services contracted in schedule 1:

11.2.1. Payment for each service will be made in consistency to the payment structure outlined in schedule 2 and the performance monitoring outlined in schedule 5.

11.3 notes the provider should issue invoices within 30 days of the end of a month to which that invoice refers. Within TRANSITION and LEO this will be relaxed to 210 days in line with amendments to 11.2.

11.4 notes that the provider should issue invoices within 30 days for any discretionary services. Within TRANSITION and LEO this will be relaxed to 210 days in line with amendments to 11.2.

11.10 and 11.13 discusses requirements on either party to pay interest should payment be late, for the purpose of simplicity on trials this clause will be removed.

The project has suggested these amendments as a temporary solution pending work on an effective settlement mechanism (for instance offering autopayment parameters) to ensure pre-trials can progress.

12. Termination

12.2 notes "either party may terminate this agreement at any time by providing ninety (90) days written notice to the other party". In principal this is appropriate, however may open a market for gaming whereby either party could terminate the agreement to then exercise market power (especially whilst the DER market is less mature) in agreeing a future deal. TRANSITION would recommend the inclusion of a fee attached to this clause in BaU. Within the TRANSITION project, no fee will be added as there will be no real network risk of cancelled agreements and hence reduced chance for gamification.

13. Service Failure

Addition 13.3.1- *If the provider continually fails to deliver on 25% of events or three consecutive events without notice, such failure will be deemed a material breach of this Agreement for the purpose of clause 12.1.*

Addition: 13.5- *in the event of a Service Failure by the provider, the company may reduce the providers and/or assets reliability index (as per Schedule 5), impacting baselining methodologies and prioritisation in future auctions or tenders.*

14. Force Majeure

No intended changes.

15. Indemnity and Liability

Clause 15.4 notes that total liability shall be limited to the aggregate total charges payable or paid to the provider under this agreement. The clause does not limit or exclude either party's liability: In the case of fraud, misrepresentation or wilful misconduct; in the case of death or personal injury; in the case of breach of a statutory right; where the Provider has invalidated such insurance referred to in clause 8 or has not complied with such insurance policies.

TRANSITION feels this is appropriate for BaU, however will reduce the first part of this agreement to reflect no liability over the value of availability charges or £100,000 whichever is lower, other than in the cases outlined above. This, drawing on learning from SSEN's Social Constraint Managed Zone (SCMZ) project, is to remove any potential barriers to entry (especially to smaller and community based groups). It also addresses ambiguity in relation to contract value that may be caused by the original clause by providing a clear cap on what this liability can be. The TRANSITION project will continue to get feedback from project partners on this as the contract develops.

16. Assignment

No intended changes.

17. Confidentiality

No intended changes.

18. IPR

No intended changes.

19. Company Property

No intended changes.

20. Data Protection

No intended changes.

21. Modern slavery and Anti-bribery

To avoid creating a barrier to entry TRANSITION will not require living wage considerations from partners. This will however be looked at favourably in tender exercises.

22. Notices

Amendment: 22.2- All formal notices or other communications to be served under this agreement ("Non-Operational Notice") shall be given in writing and shall be delivered *by email to a predefined centrally managed inbox or* sent to the address for notice set out in

Part 1 of the Flexibility Services Agreement or to such other address as each party may have notified in writing to the other Party.

Combine 22.2 and 22.5 to state: *A Non-Operational Notice shall be either; delivered by hand, sent by pre-paid post, or by first class recorded delivery post (or equivalent recorded postal delivery service); or, communicated via email.*

Combine 22.5 into 22.4 and create 22.4.3 to state: *if sent by email notices shall be deemed to have been received within 24 hours of sending or upon receiving a read receipt, whichever is faster. Where sent outside of Business Hours the 24 hour period will start from the first Business Day thereafter.*

23. Dispute Resolution

No intended changes.

24. Severance

No intended changes.

25. Third Party Rights

Amendment 25.2- The provider agrees that it may enter into agreements with other system operators that conflict with the provision of the Flexibility Services under this Agreement upon the conditions 1) set out in section 6; 2) that both parties are notified of the participation in another service.

Addition: 25.2.1- *If by participating in a conflicting service the Provider has reduced ability/reliability in response to services, the Provider acknowledges this may affect the asset and/or the companies reliability index impacting baselining methodologies and prioritisation in future events or tenders.*

26. No Agency or Partnership

No intended changes.

27. Waiver

No intended changes.

28. Entire Agreement

No intended changes.

29. Counterparts

No intended changes.

30. Governing Law and Jurisdiction

No intended changes.

31. Trial Specifics

Additional section added for TRANSITION Project.

31.1: - SSEN shall notify the Provider as soon as reasonably practicable if it is decided by the parties to the TRANSITION Flexibility Services Agreement that the Trial will not proceed. If so, subject to the DER Unit having successfully completed all DER Commissioning Tests, SSEN will not be able to reimburse any costs and expenses incurred in connection with the DER Commissioning.

4.3.1 Schedules

In addition to the changes made to the ON-P documentation given above the project has also developed the ON-P schedules below with the primary purpose of facilitating service stacking in the simplest manner for both customers and the DNO to co-ordinate.

Each schedule will be broken out into sub-sections to reflect the different services a given customer's sites are participating in and their parameters. This is referenced using the coding section outlined in 4.3 above.

Schedule one- Service Description

Schedule one within the ENA ON contract framework currently provides a description of the service in question. This has been kept largely the same with the removal of items detailing multiple utilisations per service window and recovery times. This will be to focus trial efforts and control for dependant variables when testing basic DER operability and whole system. The project will also remove service failure information from this section. Service failure implications will be provided in Schedule five.

Schedule one has added a description of flexibility services to support provider understanding/clarity and in consistency with SSEN BaU contract amends.

Schedule one will be coded based on the service being delivered. This coding will be consistent with that in section 4.3 and will be repeated for each service being procured from the customer in question. Criteria considered for each service covered in schedule one includes: the type of service (Dynamic- DSO constraint management, Sustain- Peak Management, STOR), it's location on the network (zone), customer ID (changed from unit ID as customers may aggregate multiple units into one contract), contracted service start and end dates (changed from contract start and end as this may vary between services), contracted capacity (MW/MVAR), service windows and time given to respond.

Schedule one of the ENA ON template also included service requirements; TRANSITION is likely to move these elements of development to the projects market rules. This will be reflected in the next iteration of market rules.

Schedule two- Sites/DER

What was schedule three in the ENA ON template has been moved to schedule two. This is because of the overlap caused by multiple sites and services within a single contract. As a result, before discussing charging, communication requirements and performance monitoring (all of which may be service and site dependant), it is best to define each site and service to provide an appropriate referencing structure.

Schedule two simply provides details of the DER sites in question, including: Type of asset (solar, hydro, battery, DSR etc.)[18], location (address)[19], MPAN, site contact details, capacity, planned maintenance periods and notice period required for access.

Given a site may be participating in any number of flexibility arrangements (as agreed previously with the DNO), and a customer may have multiple sites across different networks, a mapping matrix (consistent with the methodology in section 4.3) will be provided at the start of this section to visualise which sites are participating in which service and the capacity available. An example is given in Table 3. Each sites parameters will be represented in sub-sections (i), (ii)… to avoid confusion with service related sub-sections used elsewhere.

Table 3 Site Coding Matrix

Contract schedule Ref	Site	Connection Level	Service	Network Level	kW/kWh provided	Service Reference no.
i	DSR 1	LV	DSO Constraint Management	LV	100kW 100kWh	1.1.1.1.1a
ii	DSR 1	LV	DSO Constraint Management	HV	100kW 100kWh	1.1.1.1a
iii	DSR 1	LV	Peak Management	HV	100kW 100kWh	1.1.1.1b
iv	DSR 1	LV	Peak Management	EHV	100kW 100kWh	1.1b
v	Hydro 1	HV	DSO Constraint Management	HV	1000 kW 500kWh	1.1.1.2a

[18] Where assets have been aggregated to provide a service, this may also be a mix of asset types.
[19] Where assets are aggregated to one service, this may be the address of a designated asset.

vi	Hydro 1	HV	Peak Management	HV	1000 kW 500kWh	1.1b
vii	Hydro 1	HV	STOR	HV	1000 kW 500kWh	1c
viii	Battery 1	HV	STOR	Transmission	2000 kW 2000kWh	1c

This coding will then link together schedule one and schedule two in a summary table detailing the total amount being provided to each service and by which assets, as per Table 4 below.

Table 4 Flex Service Totals

Service Ref	**Sites related to service**	**kW/kWh provided**
1.1.1.1.1a	i	100kW 100kWh
1.1.1.1a	ii	100kW 100kWh
1.1.1.1b	iii	100kW 100kWh
1.1.1.2a	v	1000kW 500kWh
1.1b	iv, vi	1100kW 600kWh
1c	vii, viii	2000kW 2500kWh

Schedule three-Flexibility Service Charges

Schedule three (previously schedule two in ENA ON template) provides details around charges and invoicing. This schedule has been completely adapted from ENA ON as it was deemed inappropriate for the design of trials in TRANSITION and LEO[20]. Given the range of services outlined in schedule one and range of contract subsections (i, ii…), outlined in schedule two, that may be covered in a single contract; schedule three brings each of these elements together to detail agreed payment parameters.

Whilst this sounds like an added complication it is deemed far simpler than having multiple contracts. To mitigate against this section becoming over-complicated for trials on TRANSITION, other elements of this schedule have been reduced to elsewhere in the contract to allow this section to focus customer attention to their expected payment.

Unlike the ENA ON template this section does not include reference to: baselining (this has been moved to schedule five), payment mechanisms and timing of payments (this will be generic across services and is detailed section 11 of the contract), reduction in charges

[20] This was due to the complexity of the section when trying to facilitate multiple service arrangements in a coherent manner.

(detailed in schedule five), withholding or recovery of payments (detailed in section 11 of contract).

As a result this section will solely outline an agreed utilisation payment (per site, per service), agreed availability payment (per site, per service) and an agreed Discretionary Utilisation Fee (per site, per service) where discretionary utilisation is solely targeted around DNO asks to deliver a higher amount of a given flexibility service (i.e. in the instance another provider under-performs).

Schedule four- Communications

Schedule four contains fundamentally the same information as that portrayed in schedule four of the ENA ON template. The layout however is amended to reflect the referencing system adopted on TRANSITION. As a result, each relevant service (from section 2, Table 4) is presented alongside its specific utilisation instructions, stop instructions and the required process for enacting these.

The ENA template also provided generic information on acceptance terms, TRANSITION has deemed these parameters may need to be specific for different services and hence have moved this to within the table. The project also does not require an amended approach based on discretionary services, therefore this has been removed from the template.

Schedule five- Performance Monitoring

Performance monitoring will be particularly important on TRANSITION given the projects decision not to penalise under-delivery through financial penalties but instead through both: 1) reductions in the amount payable to customers, and 2) an asset reliability matrix which will be considered alongside commercial viability in the call-order of assets under liquid markets.

Schedule five initially outlines testing and monitoring requirements on different sites based on the services they are providing. Testing will also look to establish an asset's maximum ramp-period given this will affect the utilisation payments made by the company to the provider. As per TRANSITION's market rules this section acknowledges that:

- *"if there is a material change in an item of flexibility capacity then that item of flexibility capacity should pass the testing requirements for all flexibility services for which the Item of flexibility capacity wishes to be considered (if any) in accordance with the flexibility service description."*
- And that *"If the performance of an item of flexibility capacity is deemed to be poor by the flexibility service buyer over a number of delivery periods (in respect of a non-critical flexibility service) or at any time (in respect of a critical flexibility service), the flexibility service buyer can insist that the item of flexibility capacity should pass the testing requirements for all flexibility services for which the Item of flexibility capacity wishes to be considered."*

It will also provide an indication of the baseline methodology used to assess flexibility and any auditing processes.

Schedule five presents a table of payment reductions for under-delivery. The project assessed there drawing on both ENA ON guidance (no payment under 60% delivery), ENTIRE and the ESO (so not to underpay compared to the ESO market).

Most novel in this section will be the projects asset reliability matrix. Whilst the matrix is still to be developed it is intended it will provide:

- A two-dimensional grid measuring both the reliability of the asset in question and of the organisation providing said asset.
- Reliability will be calculated based on the probability distribution of previous load-shedding events and will be updated routinely.
    - This will make allowances for seasonal/time of day variation.
    - This will consider an approach for also acknowledging non-delivery and force-majeures events.
- This matrix may feed into future tender decisions or prioritisation of assets in short-term markets given the reliability of their delivery.

Schedule six- Service Prioritisation

The service prioritisation section is an addition to the ENA ON template. The section aims to address how a party might participate in several services (with potentially overlapping service requirements). This is an ongoing challenge for DSO and ESO market services which wish to stack their revenue streams. The ENA (2019b) acknowledges that as distribution services tend to offer lower reward than transmission services they will currently take priority.

This competitive market approach might seem justified under neo-classical economic thinking, however, does not reflect what is of greatest benefit to the wider system and may actually force transmission networks to drive prices up to ensure security of supply at grid level.

TRANSITION will adopt a more behaviour and outcome driven approach that can adapt to system priorities based on network need as opposed to willingness-to-pay. This framework approach (which may evolve throughout the TRANSITION trials) will assign priority based primarily on: 1) Market Liquidity; and 2) Network Impact.

A highly liquid flexibility market will be characterised by supply of flexibility outstripping demand, such a market: a) drives competition and cheaper prices; and b) encourages the network to procure flexibility in shorter-term markets given a lower level of reliance/certainty needed from a small subset of assets.

At current flexibility markets at transmission levels (and higher voltage distribution) are more mature and competitive than lower voltages, therefore have greater market liquidity and more options from whom to procure their flexibility. At LV however, limited market liquidity may mean that if an asset responded to a requirement on a more liquid market (i.e. at transmission level) there may not be enough flexibility to manage a constraint, risking an outage or requiring reinforcement.

On the other hand, if flexibility was prioritised on distribution networks and there was to be extensive cross-over/stacking of services; then the transmission network may loose market

liquidity to a point where it may not be able to procure the level of flexibility it requires to run the system. The impact of under-delivery on transmission networks is far greater than it might be on distribution networks and so must also be taken into account in any approach. The more impactful (on CI's and CML's) consequences of outages on higher voltage levels therefore need ultimate priority over LV networks. The same thinking might also be applied to the type of service required.

Given this consideration TRANSITION will test allocation of flexibility resources based on market liquidity. However, the project will acknowledge, as market prioritisation is assigned to less liquid LV markets it will diminish liquidity at higher voltage levels. Should this liquidity diminish to a given threshold amount at higher voltages then prioritisation (should two calls for service clash) will be reassigned to the appropriate higher voltage markets. Commercially this may mean marginally higher prices at higher voltages in the short-term, however this will come at the benefit of allowing greater service stacking, a smaller gap between WTA and WTP at LV markets and in the long-term greater competition driving prices down across the system.

A methodology for this is reflected in schedule six, however this is purely illustrative for current purposes and will be subject to more economic modelling to reflect an appropriate market liquidity index (MLI). MLIs will work better on short-term markets given the ability to procure flexibility quickly and flexibly, however they will be designed so they can also be indicated on more static longer-term markets to allow service stacking. If administered with appropriate statistical margins on market liquidity this methodology will remain consistent with market rules 6.2.2 and 6.2.3.

4.5 Peer-to-Peer services - contractor delivery

Peer-to-peer (P2P) trading is defined as "the buying and selling of energy [or energy related services] between two or more grid-connected parties" (Infinite Energy, 2020). TRANSITION will look to run two P2P services, namely:

- Offsetting: A service where one Market Actor agrees to increase its demand ahead of another Market Actor increasing its generation by the same amount, all with appropriate fail safe mechanisms.
- Maximum export capacity (MEC)/maximum import capacity (MIC) Trading: A service where one Market Actor can increase the level of export or import at one of its MPANs through purchasing excess Authorised Supply Capacity for a period of time from another Market Actor in the same area.

Peer-to-peer (P2P) trading is a key component of the services to be trialled as part of TRANSITION's objective. These P2P services have significantly different format, stakeholders and general characteristics to the more mature DSO and ESO flexibility services outlined in section 4.1 Flexibility Services. Therefore, the commercial and contractual arrangements required are distinct to match these different requirements.

The following subsections describe TRANSITION's P2P investigations to date, covering:

- TRANSITION's progress to date on P2P services;

- The current proposed contractual arrangements;
- Different stakeholder perspectives on P2P services, including a customer and DNO; and
- Interim conclusions from the work completed and next steps for the project

4.5.1 P2P trading challenges

P2P services at the distribution network level can be broadly split into:

- P2P electricity trading: the physical or commercial trading of electricity quantities in MWh terms.
- P2P access rights[21] trading: the commercial trading of connection capacity limits in MW (or MVA) terms.

Most previous work has centred on the former - the evolution of P2P electricity trading is described in Appendix 3. TRANSITION will focus on P2P access rights trading as this service provides the greatest opportunity for development of DNO capability and knowledge. The experience gained from development P2P electricity trading has delivered important learnings, although significant challenges remain to its widespread uptake and extension to P2P access rights trading. These challenges comprise both retail and network-based issues.

On the retail side, a key limitation is that P2P electricity trading can only occur between participants who have the same electricity supply company. In the UK, this is due to the existing regulations, codes and commercial arrangements that follow a “supplier hub” model. This means a single supplier is responsible for meeting each consumer’s electricity requirements. Furthermore, there are particular challenges relating to resolution of supplier volume allocation (SVA) between suppliers under the balancing and settlement code (BSC) [22]that inhibit P2P trades. Proposed BSC code changes[23] expected by the end of 2022 would address some of these limitations, however significant work remains to align the full regulatory and commercial framework with P2P electricity trading between consumers through multiple suppliers. Similar challenges inhibit true P2P electricity trading directly between consumers, as peers cannot trade with each other without explicit intervention of a supplier. However, this may be less of an issue for P2P access rights trading, particularly for generators which would require limited supplier interaction to increase their output levels.

For distribution networks, potential challenges relate to the risk of network asset damage by P2P trading due to changes in power flows over the distribution network. For purely P2P electricity trading, this is likely to be a more significant issue when volumes increase, as participants operate within their existing capacity limits. However, P2P access rights trading places significant obligations on DNOs to implement processes necessary for protecting network assets. Additionally, existing connection agreements prohibit exceedance of capacity limits - providing a strong disincentive for participants to trade access rights.

[21] More detail on access rights trading can be found here: http://www.chargingfutures.com/media/1418/scr-access-sharing-and-trading-explained.pdf
[22] https://www.elexon.co.uk/bsc-and-codes/balancing-settlement-code/
[23] See https://www.elexon.co.uk/mod-proposal/p379/

4.5.2 TRANSITION P2P services

4.5.2.1 Origin and objectives

Considering the challenges above, project TRANSITION has sought to focus on some of the key barriers affecting wider adoption of P2P services. In particular, given the participation of two DNOs in TRANSITION, we have chosen to focus on DNO challenges where the project can deliver the most valuable learning.

Specifically, the project has chosen to focus on network barriers relating to P2P trading of access rights. TRANSITION has made this choice due to the ongoing work on supplier related challenges, including BSC changes, and the relative immaturity of P2P access rights trading compared to P2P electricity trading. The trading of connection capacity limits represents a relatively unstudied area, even in the context of the nascent P2P electricity trading sector. Furthermore, recent work by the access and forward looking charges Significant Code Review has highlighted that market based trading of access rights allows users to respond dynamically to live conditions, delivering value for consumers[24]. The project seeks to develop answers to some key outstanding questions relating to P2P access rights trading:

- How can participants safely exceed capacity limits without damage to the network?
- Where do participants need to be located to provide the services?
- When can participants transact the services (including synchronisation of generation and consumption)?
- What processes do DNOs need to put in place to approve and cancel P2P capacity transactions?
- Why would participants transact the P2P services - what value do they deliver to peers and the power grid?

4.5.2.2 Services summary

To support answering these questions, TRANSITION has designed relevant P2P services to be trialled over the project[25]. The project developed these services through a workshop led by Origami Energy that sought to identify key issues faced by market actors. Participants dispatch all these services for defined periods - start time and duration - as well as capacity change (in kVA). A summary of the stakeholders, physical and market elements of the P2P services is found in Figure 7 overleaf. The following subsections describe each service in more detail along with associated barriers to implementation.

[24]See para 1.39 of https://www.ofgem.gov.uk/ofgem-publications/156098
[25] https://ssen-transition.com/wp-content/uploads/2020/05/Use-Cases-and-Services-to-be-Trialled-Phase-1.pdf

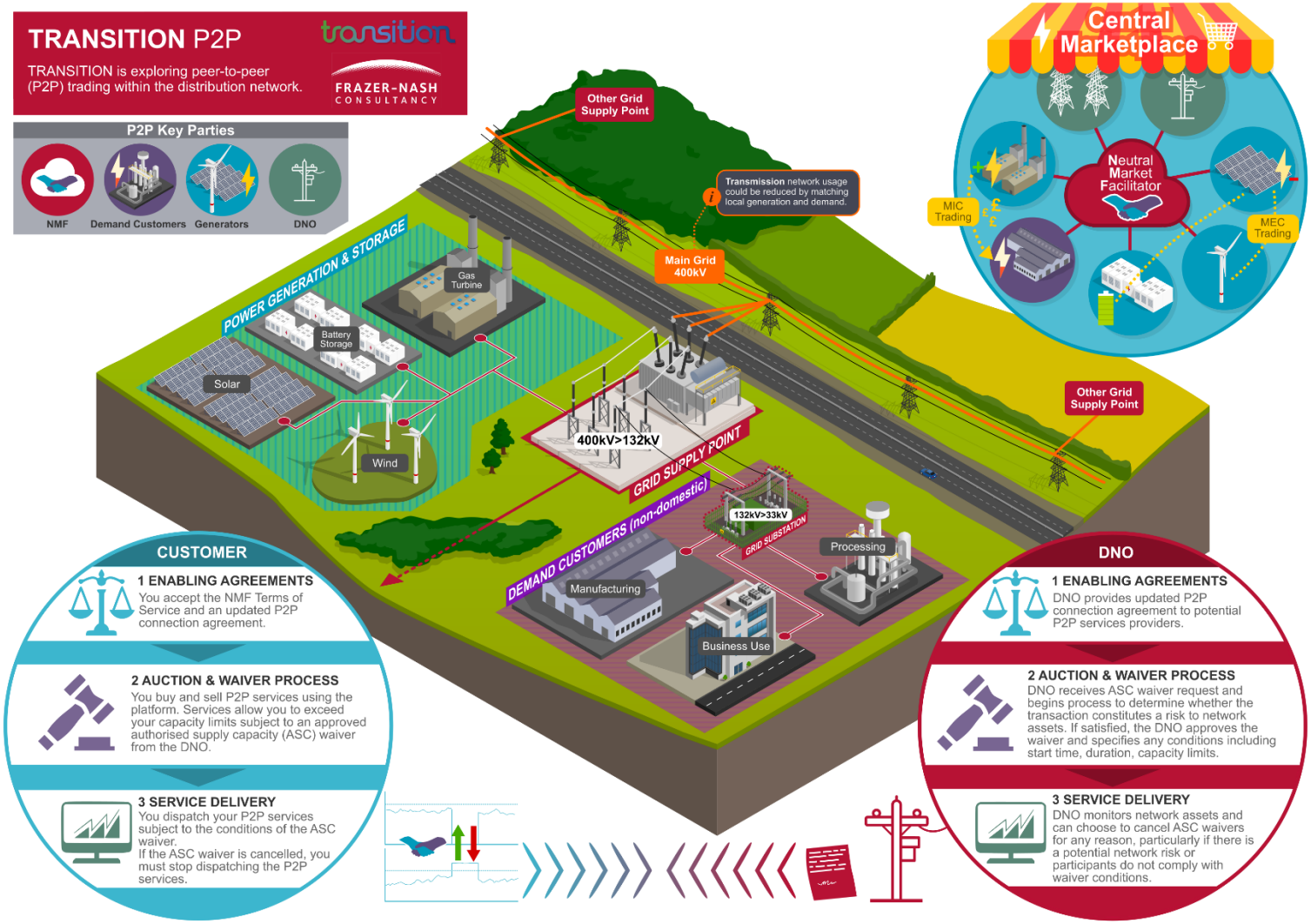

Figure 7: TRANSITION P2P services summary

4.5.2.3 MEC trading

The TRANSITION services development workshop identified the inability of generators - such as solar PV with additional nameplate capacity above contracted limits - to exceed their MEC as a significant stakeholder issue not addressed by current services in operation or development. Origami Energy's engagement with distribution connected generation customers confirmed this market gap. Therefore, TRANSITION proposed MEC trading as a potential way to satisfy this gap while safeguarding network assets. This service follows the curve described in Figure 8, with the buyer in the bottom half of the figure exceeding their authorised capacity, while the seller in the top half of the figure produces less than their MEC by the same amount during the same period.

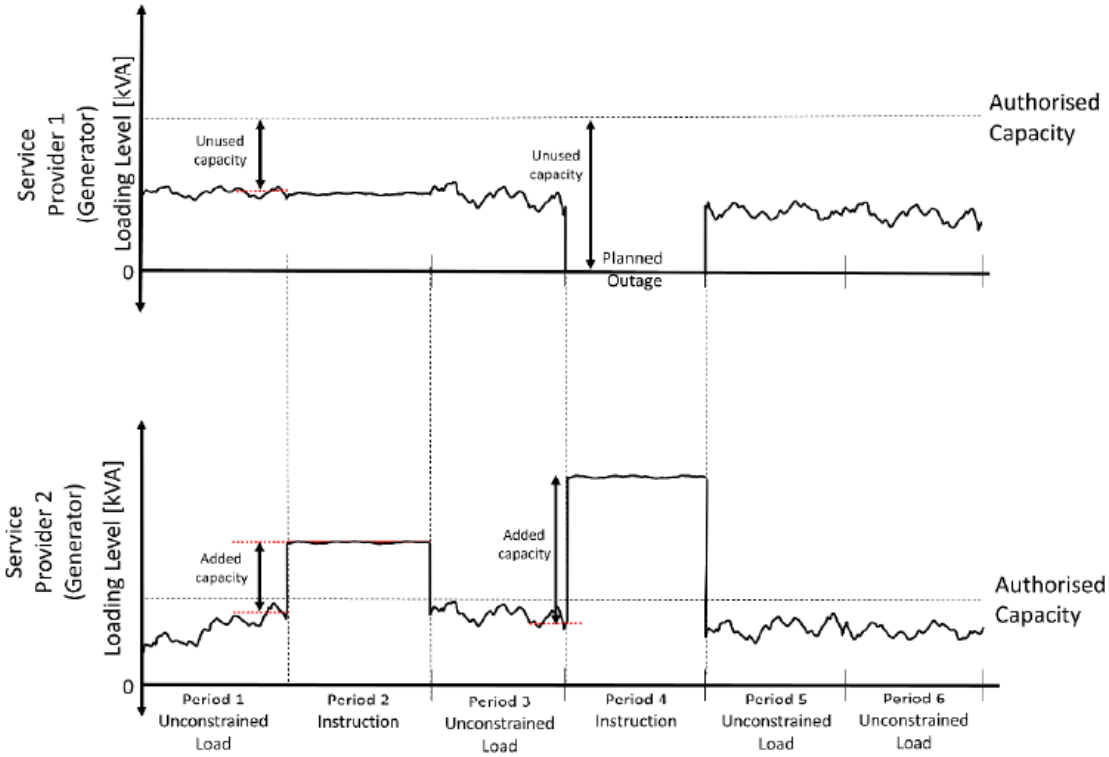

Figure 8: MEC trading service[26]

Key challenges associated with this service include both contractual and physical considerations. Provisions in connection agreements normally prevent MEC buyers from exceeding their capacity limits without breaching the terms of their agreement. Generators are unlikely to do this due to fear of disconnection or liabilities for network damage. From the other perspective, DNOs are unlikely to permit exceedances of MEC limits without processes in place to ensure damage to network assets does not occur, with associated impacts on network reliability and safety. These processes could include approval, rejection, dispatch and cancellation of this service, and must be developed in collaboration with each DNO's technical teams.

[26] https://ssen-transition.com/wp-content/uploads/2020/02/SSEN-TS-7-Oxfordshire-Programme-Trial-Strategy.pdf

4.5.2.4 MIC trading

Similar to the above, when conducting MIC trading a buyer exceeds their MIC, while the seller consumes less than their MIC by the same amount during the same period. While there are some similarities, MIC trading presents slightly different characteristics and additional challenges.

In terms of barriers to MIC trading, those noted above relating to contractual and physical considerations persist. Additionally, unique challenges include market uncertainty and network charging impacts. Firstly, it is unclear whether there is a clear market appetite for this service, yet this does not mean an appetite will not be present if it becomes available. Another consideration is the impact on network charging. A key outcome of the targeted charging review (TCR), which published its Final Decision in December 2019[27], was that fixed banded residual distribution use of system (DUoS) charges will apply to distribution connected demand customers. Charging bands will be set based on connection capacity and voltage levels. Modifications to the Distribution Connection and Use of System Agreement (DCUSA) are implementing these updates. Preliminary conclusions include that bands for residual charges should be set using customers' MIC[28]. This means that any trading of MIC under the TRANSITION proposed services must consider fairness in relation to customer's residual charges obligations[29].

4.5.2.5 Offsetting

Offsetting presents similar features to the above services, with additional implementation complexity. As shown in Figure 9, the buyer on the bottom half of the graph exceeds their MEC limit at the same time as a demand customer increases their consumption relative to the previous period.

[27] https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-decision-and-impact-assessment
[28] https://www.dcusa.co.uk/group/dcp-361-working-group/
[29] For instance, if a customer were to execute a trade to operate beyond their MIC, they would still pay the same residual charges as other customers while using more network capacity for some periods.

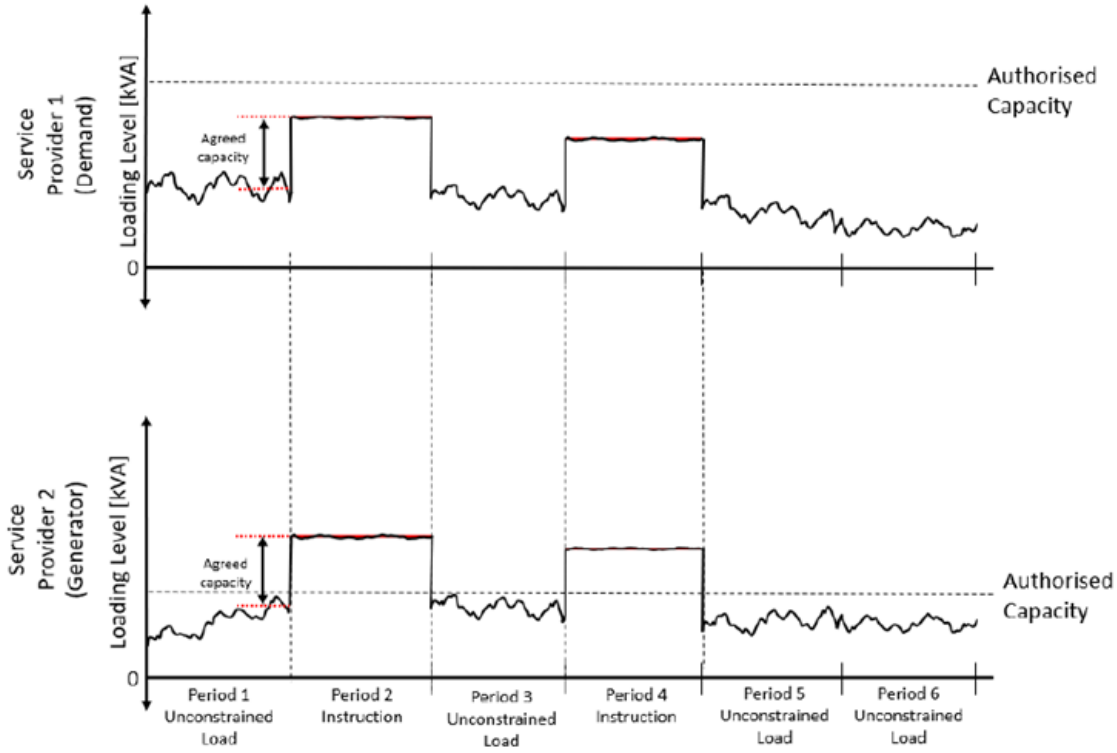

Figure 9 Offsetting service[30]

In addition to the considerations noted in Section 4.5.2.3, TRANSITION is seeking to address challenges in delivering this service. In particular, there must be a robust process for baselining demand of the seller in the preceding period to the transaction. Additionally, any processes to approve, reject, dispatch or cancel such transactions must verify this change in demand and confirm whether it avoids any damage to the network.

4.5.3 TRANSITION P2P contracts

To address the immediate requirements for trials of TRANSITION P2P services, the project has developed two new contracts:

- A P2P connection agreement.
- An NMF Terms of Service.

These contracts reflect the project's focus on DNO barriers to P2P services and TRANSITION's key objective to implement many-to-many flexibility services on the NMF platform. For future integrated P2P electricity trading and capacity trading, changes would need to occur to the electricity supply agreements to enable the energy (kWh) component of trading.

4.5.3.1 P2P connection agreements

TRANSITION has produced updated versions of SSEN's connection agreements, shown in Table 5 (copies are available on request).

[30] https://ssen-transition.com/wp-content/uploads/2020/02/SSEN-TS-7-Oxfordshire-Programme-Trial-Strategy.pdf

Table 5: Connection agreement types

Original Agreement	Description
Embedded generator connection agreement (EGCA)	Standard agreement for distribution connected generation in an unconstrained network area
EGCA* - Active Network Management (ANM) *connection agreement	Agreement for distribution connected generation in a constrained network areas

Each updated connection agreement modifies the clause that prohibits exceedance of the authorised capacity limit. These clauses are a feature of nearly all connection agreements for non-domestic demand and generation customers and stem from the National Terms of Connection, which states:

> *The Company shall only be obliged to allow the import of electricity from, and/or the export of electricity to, the Distribution System through the Connection Point at levels equal to or below the Maximum Import Capacity and/or the Maximum Export Capacity (respectively)*
>
> Clause 12.1 of the National Terms of Connection[31]

The updated agreements modify this requirement to allow exceedance of capacity limits subject to approval of an Authorised Supply Capacity (ASC) Waiver. An ASC waiver should specify the amount of electrical power in (kW/kVA) by which MEC/MIC can be exceeded for a defined duration and start time. It may also specify conditions on the seller of capacity limits to stay within a reduced capacity limit. Customers would apply for this ASC Waiver prior to the agreement of a capacity trade. This ASC Waiver is a key artefact: TRANSITION will develop associated DSO processes to support issue and cancellation of these waivers. Development of these processes should follow the principles identified by the industry-led Access charging futures forum subgroup:

1. Transparent information sharing.
2. Ability to maintain network continuity.
3. Visibility of other potential trading parties.
4. Transparent trading arrangements.

The updated connection agreements specify several key capacity limits as shown in Figure 10. MIC and MEC are characteristics of all connection agreements in scope.

[31] http://www.connectionterms.co.uk/National%20Terms%20of%20Connection%20v12.0_07%20November%202019%20(2).pdf

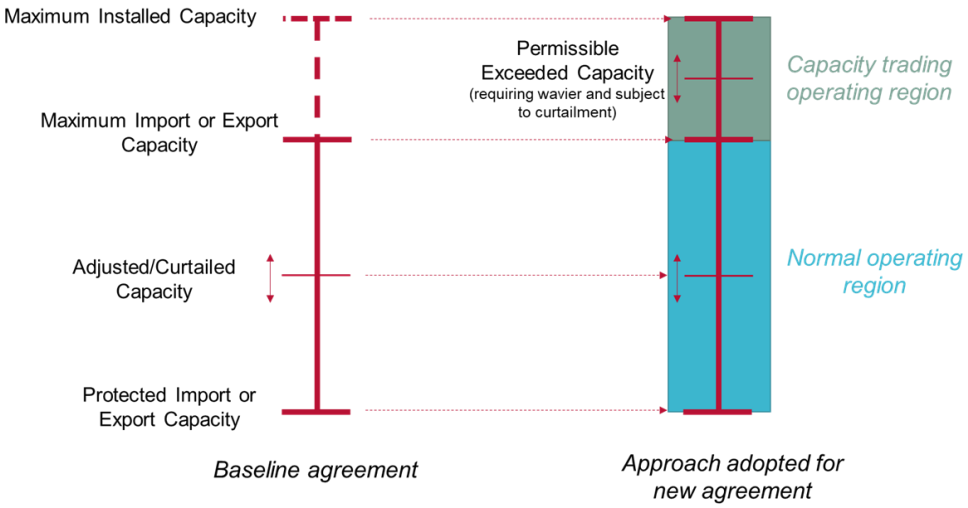

Figure 10: Capacity limits before and after modification

Table 6 describes the terminology used.

Table 6: P2P connection limit definitions

Defined term	Description	Source
Adjusted/Curtailed Capacity	Actual curtailed capacity	ANM agreements
Protected Import/Export Capacity	Capacity that cannot be curtailed	ANM agreements
Maximum Installed Capacity	The theoretical size of the physical customer connection	Some existing agreements
Permissible Exceeded Capacity	Capacity that is only available subject to an approved ASC waiver	New term

4.5.3.2 NMF Terms of Service

The NMF Terms of Service (initial draft available on request) is an agreement between the NMF platform provider and a user of the platform. This is similar to agreements for other flexibility platforms such as Piclo, or for P2P platforms in other sectors such as Airbnb. Users will sign up to these terms when first using the platform and then accept updated versions when published by the NMF operator. SSEN has drafted the initial version as interim NMF operator for the TRANSITION trials however in the future, a third party operator may take ownership of the content of this agreement.

Key provisions relating to P2P trading include those relating to facilitation of TRANSITION P2P services. For instance, the current NMF requirements include provisions for an 'Offer and Request' process to facilitate the P2P services. Another key consideration is the visibility of key participant information such as company name and MIC/MEC that would normally be confidential. Finally, this agreement requires approval of ASC waivers prior to completing transactions.

4.5.4 Stakeholder processes

Due to the novel nature of the P2P services, project TRANSITION recognises that a set of clear process steps are required for key stakeholders. The following subsections describe

provisional process flows for customers and the DNO, noting that these will evolve as the project progresses, particularly following project trials.

4.5.4.1 Customer journey

The journey for the customer - either a demand customer or generator - providing TRANSITION P2P services is outlined in Figure 11.

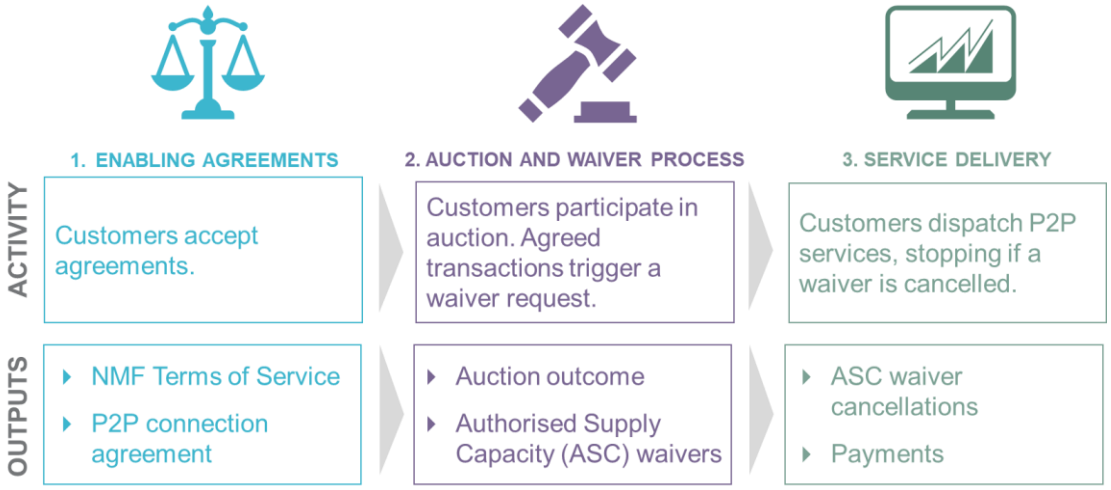

Figure 11: Customer journey process flow[32]

4.5.4.2 DNO journey

The journey in DNO facilitating TRANSITION P2P services is described in Figure 12**Error! Reference source not found.**.

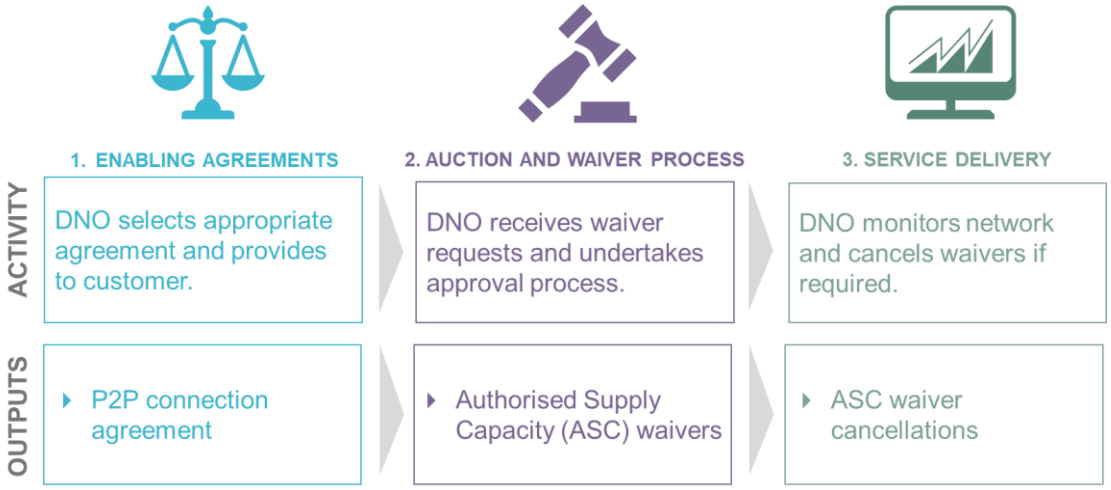

Figure 12: DNO journey process flow

While this is a high- level summary of the expected DNO role in P2P services, future TRANSITION work will clarify individual activities. In particular, the project will define processes for approval and cancellation of waivers to manage network risks.

[32] The timeframes for the initial update to connection agreement, and the duration that the updated connection agreement will be in force for, will be finalised by TRANSITION in collaboration with DNO connections teams.

4.5.4.3 Stakeholder interactions

We have mapped the stakeholder interactions for the P2P services. Figure 13 shows a representative example for MEC trading.

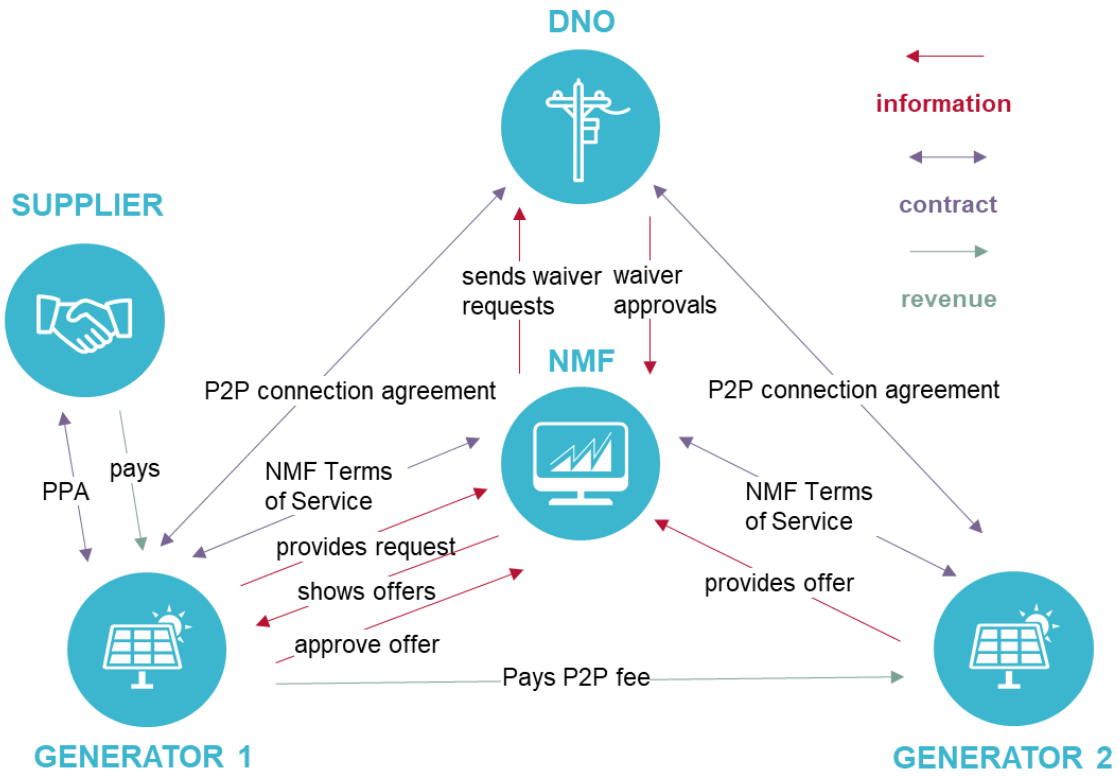

Figure 13: Interactions example - MEC Trading

4.5.5 Interim conclusions and next steps

TRANSITION has provided a set of commercial arrangements for P2P services based on where the project believes it can deliver the most valuable learning to the sector. These comprise:

- An updated P2P connection agreement for P2P services participants; and
- A draft NMF Terms of Service for users of the NMF platform to accept.

Supporting these contracts is a set of processes and guidance; TRANSITION has outlined a high-level set of process steps comprising the customer and DNO journeys for feedback. The majority of work still to be completed relates to technical processes that will enable the project LEO and TRANSITION P2P trials. These include, but are not limited to:

- Approving updated connection agreements;
- Reviewing waivers and assessing network asset impacts;
- Approving or rejecting waivers including timeframes;
- Monitoring transactions and any changes to the network; and
- Cancelling waivers.

5. Market Rules and Unintended Consequences

In February 2020 TRANSITION published a first version of its basic market rules (BMR). These rules were tested over a series of interactive workshops, with over 100 attendees, involving a variety of flexibility-based scenarios. The BMR can be viewed in the 'TRANSITION- Market Rules and Development Initial Variant' report.

Alongside this the TRANSITION project team have been liaising closely with ON WS3 P7 which looks at unintended consequences as a result of transition to DSO. These conflicts are recorded in a working document and feed into elements of the end-to-end flexibility process outlined in this report. As TRANSITION develops, we will continue to support this work on conflicts of interest, by feeding in new considerations and potential solutions. Recording of these conflicts and unintended consequences can be found at: https://www.energynetworks.org/electricity/futures/open-networks-project/workstream-products-2020/ws3-dso-transition/products.html

To ensure no conflicts of interest between the market rules and DSO service contracts/requirements laid out in this report, the project team have reviewed documents alongside one another to ensure consistency. All relevant items and considerations are noted in Table 7 below

Table 7 Market Rules and Service Contracts

	Market Rule	**Contractual/service consideration**
Flexibility	**1.1. Approval to exceed Authorised Supply Capacity**	No conflict- to be acknowledged in peer-to-peer service arrangements.
	1.2 Measurement and accuracy	No conflicts- as per contract
	1.3 Data requirements and cadence	No conflicts- as per contract
	1.4 Flexibility service testing 1.4.3 If there is a material change in an item of flexibility capacity then that item of flexibility capacity should pass the testing requirements for all flexibility services for which the Item of flexibility capacity wishes to be considered (if any) in accordance with the flexibility service description before it can participate in any transaction for that flexibility service. 1.4.4 If the performance of an item of flexibility capacity is deemed to be poor by the flexibility service buyer over a number of delivery periods (in respect of a non-critical flexibility service) or at any time (in respect of a critical flexibility service), the flexibility service buyer can insist that the item of flexibility capacity should pass the	No conflict- accounted for in Schedule 5 to reflect 1.4.3 and 1.4.4

	testing requirements for all flexibility services for which the Item of flexibility capacity wishes to be considered (if any) in accordance with the flexibility service description before it can participate in any transaction for that flexibility service.	
	1.5 Dispute of flexibility approval	No conflicts- as per contract
Location	**2.1 Conditional service trigger**	Terminology clash- conditional trigger not used in contract.
	2.2 Flexibility location	
Market Rules	**3. .1 Exceeding ASC without approval**	No conflict- as per connections agreement
	3. 2 Over procurement	No conflict- as per contract
	3. 3 Minimise scope for price arbitrage	No conflict
	3. 4 Service stacking	No conflict- as per contract
	3. 5 Standard products	Terminology clash- standard products are services. Recommended change in market rules
Flexibility Markets	**4.1 Request to buy or sell flexibility**	No conflict
	4.2 Availability 4.2.1 No item of flexibility capacity should offer flexibility to deliver a flexibility service if there is not a high chance that the flexibility will be available to deliver the flexibility service. **Unless otherwise agreed as part of their 'service stacking' arrangements.**	No conflict- addition to market rule
	4.3 Incentives and Penalties	No conflict- as per contract
	4 .4 Participation in markets 4.4.3 Market Actors can offer items of flexibility capacity across multiple markets to deliver different flexibility services. Once an item of flexibility capacity has been accepted to deliver a flexibility service the Market Actor should remove that item of flexibility capacity from being considered for any other flexibility service in all flexibility markets unless those flexibility services are approved for the stacking of flexibility services.	No conflict

	4.5 Acceptance of flexibility offers	No conflict
	4.6 Selection of successful offers	No conflict- requirement on flexibility buyers to publish evaluation criteria for determining successful flex offers.
Availability	**5.1 Forecast of availability**	No conflict- addition to contract as item 3.7.3
	5.2 Changes to availability	No conflict- as per contract
Service Delivery	**6.1 Delivered energy**	No conflict- ramp up/down added to ON contract.
	6.2 Priority of access 6.2.2 In the event of an unplanned issue that threatens the local or regional distribution electricity system the DSO / DNO has priority access to items of flexibility capacity over the ESO and other Market Actors. 6.2.3 In the event of an unplanned issue that threatens the transmission network or the electricity system the ESO has priority access to items of flexibility capacity over the DSO / DNO and other Market Actors. 6.2.4 If priority access to items of flexibility capacity is declared, the affected Market Actors shall be compensated as if the delivery of any flexibility services, ancillary services or balancing mechanism had occurred during the period of priority access. If the item of flexibility capacity does not have a relevant price for the delivery of flexibility, the parties will determine a price with reference to prices being paid to other Market Actors to deliver the same flexibility service or through negotiation, both parties not being unreasonable.	Terms 6.2.2 and 6.2.3 added to Schedule 5 of contract. Section 6.2.4 clashes with schedule 6 of the contract and should be updated in next market rules iteration
	6.3 Failure to deliver as per contract 6.3.2 If a flexibility transaction is affected by a DSO / ESO claims of priority access or where an agreed flexibility transaction is interrupted by the DSO / ESO for any reason, the relevant Market Actor offering the item of flexibility capacity should be compensated in accordance with 6.2.4.	Section 6.3.2 clashes with schedule six of the contract and should be updated in next market rules iteration

	6.4 Force Majeure	No conflict- provides further details as to Force Majeure events.
Settlement	7.1 Data	No conflict- as per contract
	7.2 Reliability of performance	No conflict- as per contract
	8 Issues not covered	No conflict- covered in contract

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Appendix 1- Baseline Methodology Sources

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Appendix 2- Baseline Methodology Mathematical Formulation

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Section 7.2 Demand Side Response

For DSR technologies, analysis is required to assess the performance during a DSR Event.

The approach to be used for assessing performance of DSR based DSR Services compares the actual load profile during the DSR Event against a baseline demand profile derived to represent the demand profile that would have been seen had a DSR Event not been called.

This baseline methodology takes a day comparison approach, using day matching to establish the days to be used to derive the baseline demand profile.

The stages involved in developing the baseline demand profile and assessing performance during a DSR Event are set out below, with the associated formulae presented for each stage.

The 22 hour period commencing at 2am will be used for Performance Assessment, as this provides clarity in the event that a DSR Event day or any prior Eligible Days coincide with a clock change between GMT and BST or vice versa. Further, where the DSR Event day or one of the Eligible Days coincides with a clock change, the data used to assess performance must consider each day on a clock consistent basis, i.e. such that 4pm on a GMT day is aligned to 4pm on a BST day.

The prior 10 Eligible Days (5 days for weekend DSR Events) will be assessed and the 6 days (3 days for weekend DSR Events) with total daily electrical consumption (kWh) most closely matching the total daily electrical consumption on the event day (excluding the Capacity Response event period) will be used to derive the baseline demand profile.

The total daily electrical consumption outside the DSR Event period for each of the prior Eligible Days is calculated using the following formula:

$$P_d = \frac{\sum_{m=1}^{f-1} k_{md} + \sum_{m=l+1}^{1320} k_{md}}{((1320-(l-f))/60)}$$

where:

P_d total electrical consumption outside DSR Event period on day d (kWh)

d one of the prior Eligible Days

k_{md} kW reading for minute m within the 22 hour period on day d

f first DSR Event minute within the 22 hour period

l last DSR Event minute within the 22 hour period

The total daily electrical consumption outside the DSR Event period for the DSR Event day is calculated using the following formula:

$$T = \frac{\sum_{m=1}^{f-1} k_m + \sum_{m=l+1}^{1320} k_m}{((1320-(l-f))/60)}$$

where:

T total electrical consumption outside DSR Event period on day d (kWh) one of the prior Eligible Days

K_m kW reading for minute m within the 22 hour period on day d

f first DSR Event minute within the 22 hour period

l last DSR Event minute within the 22 hour period

The prior Eligible Days used to derive the Baseline for performance assessment are selected by comparing the total daily electrical consumption outside the DSR Event period for each of the prior Eligible Days with the total daily electrical consumption outside the DSR Event period for the DSR Event day in accordance with the following formula:

total electrical consumption outside DSR Event period on the DSR Event day (kWh)
kW reading for minute m within the 22 hour period on the DSR Event day

first DSR Event minute within the 22 hour period last DSR Event minute within the 22 hour period

$$S_d = |T - P_d|$$

where:

S_d absolute difference for use in ranking to identify minimum difference Eligible Days

T total electrical consumption outside DSR Event period on the DSR Event day (kWh)

P_d total electrical consumption outside DSR Event period on day d (kWh)

The required number of prior Eligible Days with the smallest difference in absolute terms will be used in the assessment.

For weekday DSR Events (Monday to Friday), Eligible Days are those that do not fall under one of the categories: 1) Weekends (Saturday and Sunday), 2) Bank holidays, 3) DSR Event days and 4) Days for which the DSR Service was declared unavailable.

For Saturday DSR Events, Eligible Days are previous Saturdays that do not fall under one of the categories: 1) DSR Event days and 2) Days for which the DSR Service was declared unavailable.

For Sunday DSR Events, Eligible Days are previous Sundays that do not fall under one of the categories: 1) DSR Event days and 2) Days for which the DSR Service was declared unavailable.

For weekday events, an Unadjusted Baseline is derived by averaging the minute-by-minute interval meter data from each of the 6 out of 10 Eligible Day profiles, in accordance with the formula below:

$$b_m = \frac{\left(\sum_{d=1}^{6} k_{md}\right)}{6}$$

$$B_{ini} = (b_1\ b_2\ \ldots\ b_{1320})$$

where:

b_m Unadjusted Baseline kW reading for minute m

d one of the 6 out of 10 Eligible Days

k_{md} kW reading for minute m within the 22 hour period on day d

B_{ini} Unadjusted Baseline

For Saturday or Sunday events, an Unadjusted Baseline is derived by averaging the minute-by- minute interval meter data from each of the 3 out of 5 Eligible Day profiles, in accordance with the formula below:

$$b_m = \frac{\left(\sum_{d=1}^{3} k_{md}\right)}{3}$$

$$B_{ini} = (b_1\ b_2\ \ldots\ b_{1320})$$

where:

b_m Unadjusted Baseline kW reading for minute m

d one of the 3 out of 5 Eligible Days

k_{md} kW reading for minute m within the 22 hour period on day d

B_{ini} Unadjusted Baseline

The Unadjusted Baseline is adjusted as a refinement to align the baseline to the DSR Event day. The adjustment is derived from the interval meter readings for the 4 hours prior to the DSR Event. The differences between each of the minute-by-minute readings are averaged to generate an additive adjustment. The formula for deriving the Baseline Adjustment is as follows:

$$A = \frac{\sum_{m=1}^{240} (D_{f-m} - b_{f-m})}{240}$$

where:

f first DSR Event minute within the 22 hour period

D_{f-m} kW reading for minute f-m within the four hours prior to the DSR Event

b_{f-m} Unadjusted Baseline reading for minute f-m within the four hours prior to the event

A Baseline Adjustment (kW)

The Baseline Adjustment is applied symmetrically (i.e. adjusting the baseline positively or negatively) to each of the minutes in the Unadjusted Baseline to create the Adjusted Baseline to be used for performance assessment, in accordance with the formula below:

$$B_m = (b_m + A)$$

$$B_{adj} = (B_1 \, B_2 \ldots B_{1320})$$

where:

b_m Unadjusted Baseline kW reading for minute m

A Baseline Adjustment

B_m Adjusted Baseline kW reading for minute m

B_{adj} Adjusted Baseline

The load profile for the DSR Event day is then compared to the Baseline Demand calculated above to determine the response achieved by the DSR site. The formula for assessing the Supplier(s) Response against Baseline Demand is as follows:

$$R_{sm} = \sum_{m=f}^{l} (B_m - D_m)$$

where:

B_m Adjusted Baseline kW reading for minute m

D_m DSR Event kW reading for minute m

F first DSR Event minute within the 22 hour period

L last DSR Event minute within the 22 hour period

R_{sm} DSR Event Response for minute m at the site (kW)

The Supplier(s) Event Response profile is then compared to the contracted Capacity, and the Supplier(s) Response will be considered successful for the purposes of the Utilisation Payment and Availability Payment where the reduction achieved across the DSR Event equates to at least 90% of the contracted Capacity. SSEN reserves the right to raise this threshold of 90% of delivered Capacity after a Supplier(s) DSR Service has been operational for a full 2 years.

The Energy Delivered during the DSR Event is then calculated in accordance with the formula below:

$$E = \frac{\sum_{m=f}^{l} (B_m - D_m)}{((l - f) / 60)}$$

where:

B_m Adjusted Baseline kW reading for minute m

D_m DSR Event kW reading for minute m

F first DSR Event minute within the 22 hour period

l last DSR Event minute within the 22 hour period

E DSR Event Energy Delivered (kWh)

For performance verification purposes, metered minute-by-minute kW data for the day of the DSR Event and prior Eligible Days is to be provided to SSEN in both Excel spreadsheet and CSV format, with data required for each of these formats as follows:

- Excel spreadsheet - data for the event day and 10 prior Eligible Days - to support data analysis, an Excel spreadsheet template will be provided for collection of the minute-by- minute meter reading data for the DSR Event day and prior Eligible Days; and
- CSV format - data for the event day and the preceding 29 days.

SSEN reserves the right to review the approach used for the analysis and adapt it if necessary, and in agreement with the DSR Supplier in question, prior to commencement of the DSR Service and during the first operational Service Window. This may include a move to a Maximum Base Load ('drop-to') approach for very variable load profile customers.

Whilst the above approach for assessing DSR services has been outline the Company will consider alternatives to the above methodology that can be provided by DSR Suppliers.

Appendix 3- P2P Background

Drivers of P2P trading

Peer-to-peer electricity trading is often associated with the "four Ds" of power grid evolution, per Figure 14.

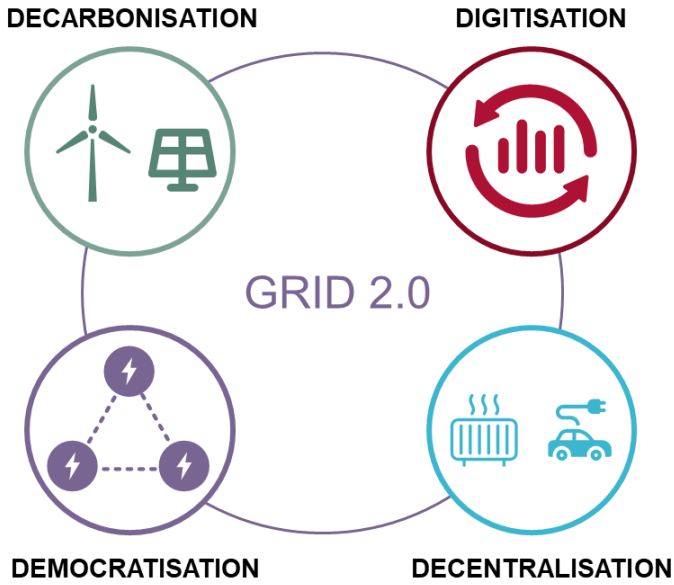

Figure 14 Grid evolution driving P2P trading

In the previous grid paradigm, large centralised thermal generators produced electricity that was transmitted over large distances to consumers. In the evolving grid, there is a decentralisation of generation and demand, including distributed behind the meter generation, local charging of electric vehicles (EVs) and electric heat pumps. These changes accompany a decarbonisation of power sources: generation at all grid scales is steadily reducing in carbon intensity with the advent of cheap solar and wind technologies.

Digitisation of the power grid enables these changes, with increased usage of smart metering by consumers, along with advanced control and monitoring developments for larger generators and demand customers. Finally, all of these factors lead to a democratisation of power which is at the heart of P2P trading; consumers and generators at all scales want to be

able to trade with one another without the need for a trusted third party. These desires reflect behavioural trends for community energy and local resilience.

Previous P2P trials

Previous trials have sought to support this democratisation through use of modern technology with P2P trading in the power sector broadly grouped into:

- P2P electricity trading: the physical or commercial trading of electricity quantities in MWh terms
- P2P access rights[33] trading: the commercial trading of connection capacity limits in MW (or MVA) terms

Out of these two use cases, the former has dominated - reflecting the relatively novel concept of access rights. P2P electricity trading has been particularly successful in Western Europe, as shown by the examples in Table 8 - sorted by date of implementation.

Table 8 P2P trading key projects summary

Project leads	Project name	Summary	Number of participants	Country	First trading date
Vandebron	Vandebron	Supplier only P2P electricity trading	200,000 households[34]	The Netherlands	2014
Good energy, Piclo	Energy matching trial	Supplier + tech platform P2P electricity trading	25 generators, 12 business customers	United Kingdom	2015
Powerpeers	Powerpeers	Supplier only P2P electricity trading	1000s of generators & consumers	The Netherlands	2016
Lumenaza	Regionah Energie	Tech platform P2P electricity trading	71 producers	Germany	2017
Power Ledger, Synergy	RENeW Nexus	Supplier + blockchain P2P electricity trading	50 households initially	Australia	2018
SunContract, SONCE energija	SunContract	Supplier + blockchain P2P electricity trading	5,000 registered users	Slovenia	2018
Centrica, Verv, L03 energy	Cornwall Local Energy Market	Supplier + blockchain P2P electricity trading	100 participants initially	United Kingdom	2019
EDF, Electron, UCL	Project CommUNITY	Supplier + blockchain P2P electricity trading	62 households	United Kingdom	2019

P2P electricity trading has seen widest uptake in the Netherlands. Vandebron and Powerpeers are direct competitors in the Dutch market, both providing a large number of customers the opportunity to choose their own energy sources. These sources can either be generators or other households that have their own generation installed - known as prosumers. When choosing between these options, households can see the components that make up the tariff, including energy price paid to the generator, supplier costs, network costs and taxes. If an individual generator is not selected, consumers receive either a fixed or variable tariff by default, according to their contract preference. Suppliers then pay prosumers

[33] More detail on access rights trading versus sharing can be found here: http://www.chargingfutures.com/media/1418/scr-access-sharing-and-trading-explained.pdf
[34] https://vandebron.nl/goeie-energie

a premium, in addition to any feed-in-tariff, for the energy generated. This flexible model allows consumers to retain many of the desirable features of their standard energy bill, while being able to choose the location and carbon intensity of their purchased generation. The supplier then arranges for the payment of generators, network charges and taxes as normally. This facilitation role has allowed consumers to meet some of the key aims of P2P electricity trading, including supporting local, low carbon generation.

This supplier-led concept has also been trialled in the UK with technology company Piclo teaming up with supplier Good Energy to deliver energy matching between business customers and generators. Conducted in 2015, this trial allowed customers such including tourist sites, hotels, factories and farms to choose energy from local wind, solar and hydro generators. The energy matching between generation and consumption was then visualised using an early version of the Piclo platform. More recently, the Cornwall Local Energy Market (CLEM) led by supplier Centrica and supported by EU funding, has trialled P2P electricity trading between consumers and generators in Cornwall. This involves the trialling of blockchain technology provided by LO3 energy to facilitate P2P electricity trading between geographically dispersed consumers and generators. A consortium led by EDF Energy implemented a related use case in 2019. This allowed residents of Elmore House in South London to trade energy with a solar PV installation (installed on the roof of the premises) via a blockchain developed by software provider Electron. These projects reflect common aims of enabling community energy and supporting decarbonisation objectives, with increasing support of modern technologies such as blockchain.

This trend in blockchain use builds off developments the financial sector and mirrors power sector applications in other countries. Blockchain is part of a family of distributed ledger technologies (DLT) that implements a distributed database, with copies stored by each participant. A key advantage of blockchain for P2P trading is that it requires no trusted third party. This has contributed to the success of the well-known Bitcoin currency as well as more general blockchains such as Ethereum. The latter has been a popular choice for P2P electricity trading, including the Slovenia-based SunContract platform. SunContract, a technology company, partnered with energy supplier SONCE to provide a token-based electricity trading service for dispersed geographical participants. Other use cases include “private wire” based electricity trading such as the RENeW Nexus project in Western Australia led by blockchain company Power Ledger and supported by supplier Synergy. RENeW Nexus initially allows residents of a housing development to trade electricity with solar PV installed on the roof, with expected future expansion to a community battery. All of these projects reflect the aim that in the future, regulatory and business changes can enable P2P electricity trading with less or no supplier involvement - reflecting an increased democratisation of energy.