AFRY

Making Future

AFRY
ÅF PÖYRY

Reactive power market design – Summary report

Report to National Grid ESO

MARCH 2022

nationalgridESO

AFRY
ÅF PÖYRY

ABOUT AFRY

AFRY at a glance

SECTOR EXPERTISE

Core sectors:

Energy

Bioindustry

Process Industry

Automotive

Infrastructure

ENGINEERING

Owners/Lenders engineering

Detail engineering

Operational services

Project management & execution

Technical studies

ADVISORY SERVICES

Forward looking market analysis

Strategic advice

Operational excellence

Transactions services

DESIGN

Architecture

Urban planning

Digital/UX design

Lighting & Sound design

Product design

DIGITALISATION

Software engineering / development

AI / Robotics / Drones / 5G

System integration and management

WE HAVE

16,000

Employees globally (as of 2021)

ANNUAL REVENUE

1.95 bn

euros in 2021

NUMBER OF COUNTRIES WITH OFFICES

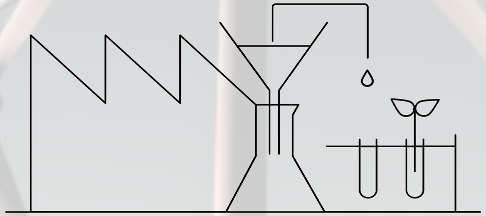
>50

NUMBER OF COUNTRIES WITH PROJECTS

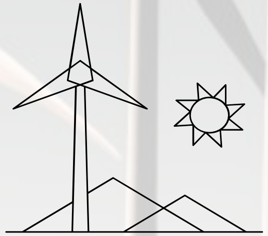
>100

4 Growth Drivers

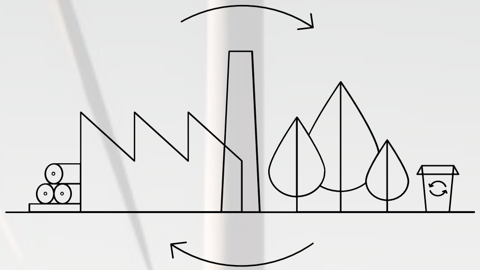
Infrastructure



Food & Life Science



Clean Energy

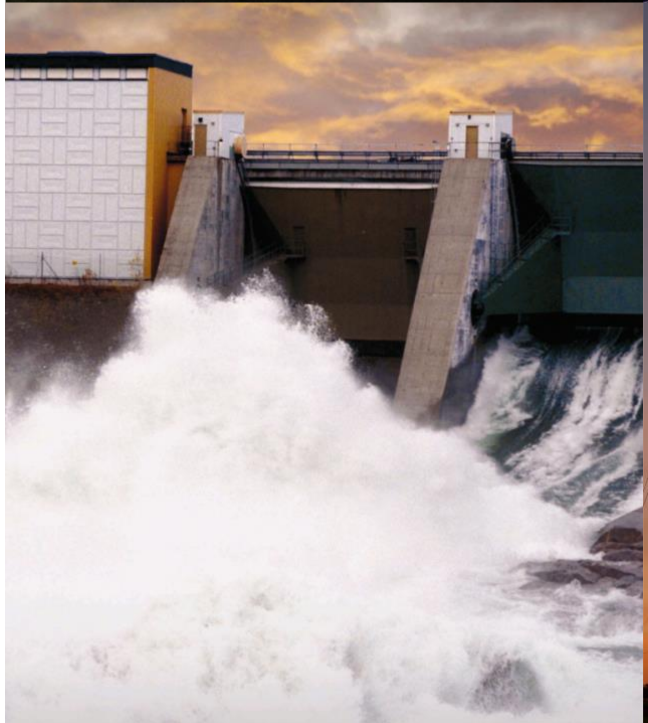


Bioindustry

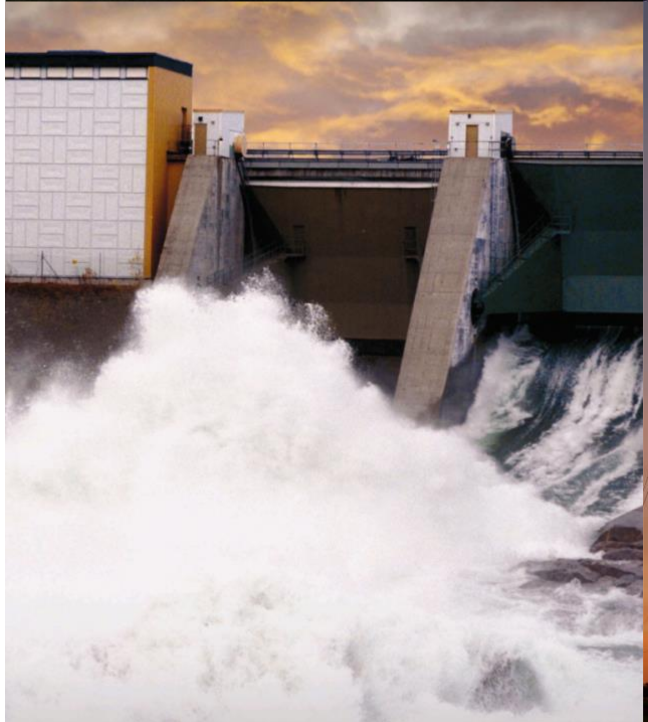
Disclaimer and Rights

Agenda






Agenda



Preface

- This project was initiated by National Grid ESO as a part of their strategy towards a zero-carbon system that will take GB to net zero by 2035
- It is one of NGESO's innovation projects funded by the Network Innovation Allowance (NIA)
- The project presents recommendations for a high-level design for a reactive power market, as well as providing new analysis tools for the assessment of reactive power needs and solutions
- This report details the core market design process, including options considered and recommendations
- The project does not present a final decision: further assessment; regulatory and detailed design considerations; and consultation with industry will be needed to crystalise the way forward
- AFRY has undertaken this project in conjunction with Energynautics, DotEcon, Ignis Markets and a dedicated ESO team with input from ESO subject matter experts
- The project started in September 2021 and finished in March 2022

Headline messages

Current arrangements are sufficient in ensuring system security today but expected future challenges can be met **more efficiently with reform** to existing arrangements. We have explored areas where a new market design can increase cost efficiency, improve system security and broaden participation from zero-carbon providers of reactive power

Reactive power **demand and costs have increased** in recent years, whilst **legacy providers** to manage reactive issues have begun to **retire** or have been pushed increasingly **out of merit** – we are expecting this trend to continue under existing arrangements

There is **additional reactive capability** embedded in the distribution networks that could help to resolve **transmission level** voltage issues, but due to DSO topology and rules around reactive power for providers in the distribution network, it is unclear how much reactive can be **transferred to the transmission network effectively**

Where large reactive power requirements exist, **investment** in new assets can **reduce costs to consumers** but only if sufficiently **robust signals** are in place for participants to site their assets effectively

Both a nodal and a zonal approach were assessed as part of the project. A **zonal approach** was found to be **unworkable** for enduring procurement applications given the technical realities associated with reactive power and the need to secure the system

Long-term contractual timeframes mean that ESO is able to ensure **system security** by giving participants a higher degree of certainty in making investment decisions – the assessment of TO counterfactual solutions at this stage ensures **value for consumers**

Including a **short-term** market ensures there is an appropriate route to market for a broad range of potential participants, facilitating providers which may be exposed to volatile opportunity costs, high variable costs, and/or low availability visibility – ultimately increasing competition & resources available and promoting **value for consumers** and contributing to **system security**

Headline recommendations

The project has delivered a market framework designed to meet the challenges faced by both the ESO and providers. It should form the **foundation for the way forward**, towards the implementation of a desired end-state market solution

As part of meeting the increasing demand in a cost-efficient way, we recommend that all commercial providers should ultimately be eligible to participate, though to only be selected if they bring a **benefit to the system** in terms of **incremental capability** ('additionality') and/or **cost efficiency –** this means incentives will be available for providers in return for actions which benefit consumers

DSOs will need to re-run network studies to understand limitations, and potentially modify connection agreements to allow providers on the distribution network to provide reactive power services. This will further require a **coordinated approach** to implementation

A **methodology** has been developed to define nodal MVAr requirements, node-to-node effectiveness, and specific provider-to-node effectiveness. This enables a consistent, transparent and repeatable way to **produce market signals**

Based on the technical analysis we are recommending a **nodal market**, where reactive power requirements are identified and stated per node, and effectiveness factors are also calculated per node for the different products

We have recommended a market design that is run over **two timeframes**

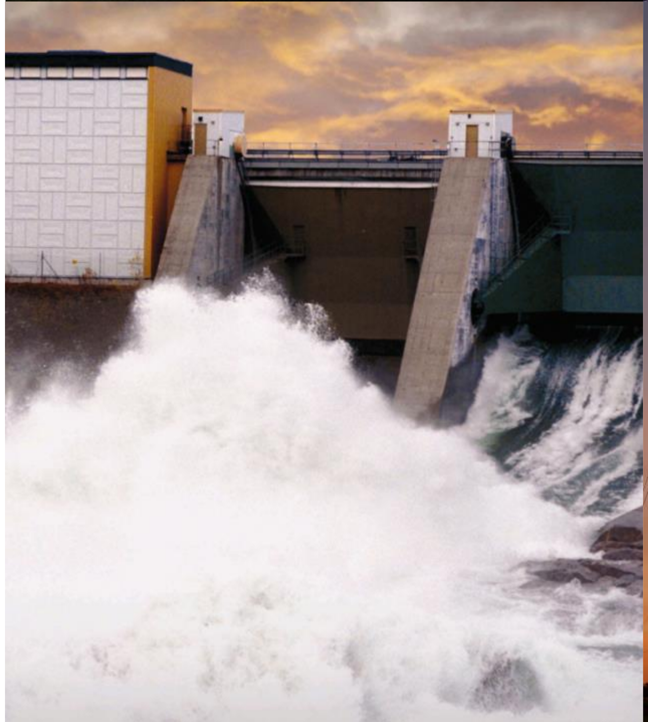
- **Long-term** annual markets operating in **investment timeframes** which offer multi-year contracts to underpin investment in assets, complemented by annual **year-ahead** contract rounds to finesse procurement
- **Short-term** market operating at the **day ahead** stage to enable participation of assets unable to make long-term commitments

Further **engagement with Ofgem and TOs** to settle on framework for TO assets' indirect participation

Formal consultation with stakeholders should be held ahead of launch to understand residual challenges for some provider types and to conclude on specific design features

Agenda






ESO is exploring an appropriate market solution to resolve the increasing challenges related to reactive power

CONTEXT

Net-zero

NGESO's role in facilitating the energy transition will be crucial. System security is one of the primary challenges in the transition towards a decarbonised power system – ensuring continuity of supply in an evolving energy mix.

System security

The local nature of reactive power issues, and the changing locations in which assets are choosing to connect to the system, as well as the technological shift away from large thermal power stations presents a challenge for NGESO in keeping the system secure and reliable.

Cost

Spend on voltage services has increased and is likely to grow as system need for reactive power increases, hence there is need to procure reactive power services in a more economic and competitive way.

Opportun-ities

New technical solutions could offer a benefit to NGESO, consumers and market participants. To realise these projects and facilitate the right assets in the right places, a framework to competitively reward effective providers is needed.

PROJECT FOCUS

Objective

This project is exploring an appropriate market solution to resolve the challenges for reactive power, ensuring cost efficient provision to maintain system voltage security in the context of a zero-carbon system

Key questions

- What are the key design choices for a reactive power market?
- How do we define the need for reactive power in a standardised and reliable way?
- How should the location of reactive power providers be accounted for in meeting the needs?
- Which type of technologies can provide reactive power, where are they located and what are their key blockers and enablers?
- What are the benefits of reform to current arrangements?

This document presents a summary of the results from five project workstreams, together giving answers to the key questions that has led to the final recommendations

1 Scene setting

- Outlining current arrangements, shortcomings and future challenges
- Defining market objectives

2 Market analysis

- **Heat-map** of current and potential future providers
- Technology **case studies**
- **DER** blockers and routes to market

3a Defining demand

- **Modelling** 2025 requirements based on FES[1] scenarios

3b Requirement methodology

- Develop a repeatable **methodology** for creating market signals of demand, considering; volumes; effectiveness; and location

4 Market design

- Design strawmen, qualitatively assess and provide recommendation on end-to-end market design for reactive power

5 Economic modelling

- Give a view on cost, volumes, changes in carbon emissions and shape of requirements.
- Test market design elements of the strawmen

→ **Recommendation and way forward**

[1] Future Energy Scenario

INTRODUCTION

We have explored all aspects of potential market designs through multiple workstreams

Scene setting:

- We investigated current arrangements, presenting the physical, organisational and economic layers of today's reactive power arrangements. This informed how a potential Reactive Power Market could address today's shortfalls and challenges.

Market analysis (understanding the supply):

- To understand market potential for reactive power, we examined case studies of potential providers of reactive power looking at their technical MVAr capabilities and costs, to understand the potential for these resources in a reactive power market.
- Supplementary to this, a heat-map of reactive power providers across GB was created, to inform about the size and location of providers' MVAr injection capability (accessible today + additional capability from known assets in 2025).
- We have drawn on information developed in the case studies, heat-map, and engagement with potential providers throughout the market design process.

Technical study (understanding the demand and designing requirement methodology):

- The technical team has studied, through modelling using PowerFactory, the system need for reactive power, based on ETYS 2025, and FES 2025 scenarios.
- The study provided an understanding of future (2025) requirements and was used as key input in the economic modelling of the market.
- The technical methodology is intended to be used as a tool for forecasting MVAr needs on an ongoing basis. The team studied and tested numerous model variations: establishing how best to forecast the requirements; whether it should be done on a zonal or nodal basis; and how provider effectiveness factors should be defined.
- The outcome form an essential part of the project, as it addresses the technical possibilities and limitations considering the locational requirements, and the effectiveness of providers at meeting these needs. Once determined, these parameters feed into the overall assessment process.

Market objectives:

- We agreed on a set of primary and secondary objectives with ESO that reflect the goals for a Reactive Power market. These principles form the criteria by which a new design was assessed.

Market design:

- Initially, we identified critical design choices that can materially impact on both providers and ESO in the market arrangements and grouped these choices (and associated options) into 'building blocks'.
- These were developed into internally consistent (strawman) options that could be compared and assessed, resulting in an initial listing of four options.
- Each option is constructed in terms of the underlying design philosophy, sufficiently broad to assess the merits and drawbacks of various design choices when scrutinised.
- An appraisal was undertaken to understand to identify design choices that best facilitated our objectives. We also ruled out design choices that performed poorly against objectives or presented an unacceptable level of risk for unintended consequences to manifest.
- We made an evidence-based recommendation of a preferred option against the objectives. The selection and refinement of the options have been determined by the AFRY and ESO team.
- Consideration of the options was informed by industry in public webinars and surveys, and by the core AFRY & ESO team, leading expert workshops, case studies and modelling work.
- The AFRY & ESO team has contributed its knowledge and experience in considering the options and identified areas that require further analysis and development.

Economic modelling:

- As part of the assessment of the market design and to form a view on the case for change, AFRY has modelled the reactive power market over the different timeframes to test market design elements against the base case scenario (no change).

Recommendation and way forward:

- We have made recommendations on critical next steps as part of refining the high-level market design.
- These are mainly related to outstanding regulatory issues, market implementation planning and readiness.

We have relied on a range of sources to support the recommendations

Sessions with ESO experts

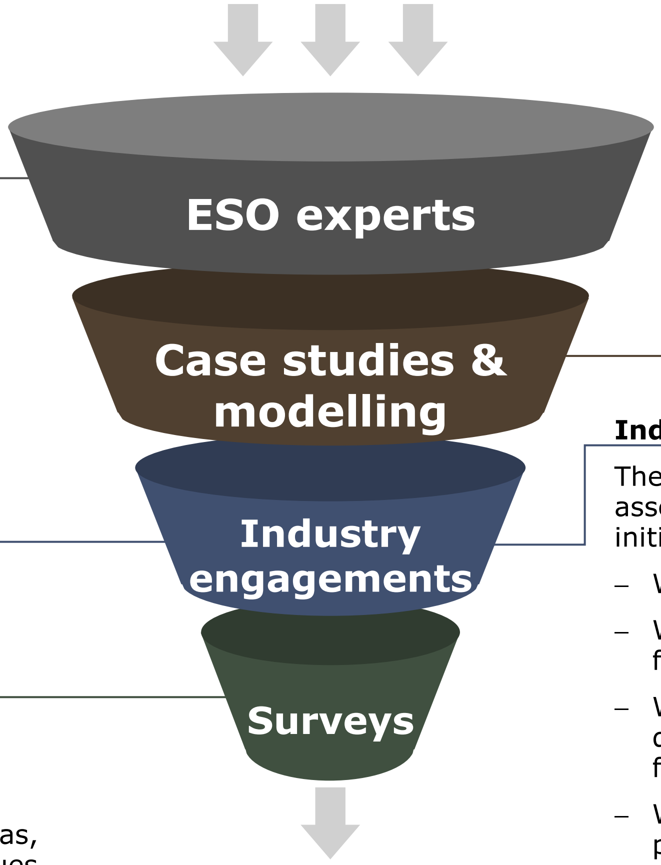
- Control room & markets team: Multiple expert sessions (day power system management, operational energy management) probing the system operation planning, decision-making process and dispatch, and understand how a potential reactive power market would work.
- Pathfinder team: Multiple engagements analysing the wider approach to current Pathfinders, distilling key challenges (long-term risk, eligibility), and deep-dives on specific topics to inform design choices throughout the process.

1-2-1 sessions

- Inputs from 1-2-1 sessions held by ESO throughout 2021, helped forming a view on key strategic questions and design aspects, specially considering key blockers and enablers.

Surveys

- Inputs from industry to design an effective market: information and evidence from industry surveys.
- The surveys sought evidence on a range of topics such as, technology capability, technology costs, investment issues, lead times, cost structures, decision-making in dispatch timeframes.



Case studies & modelling

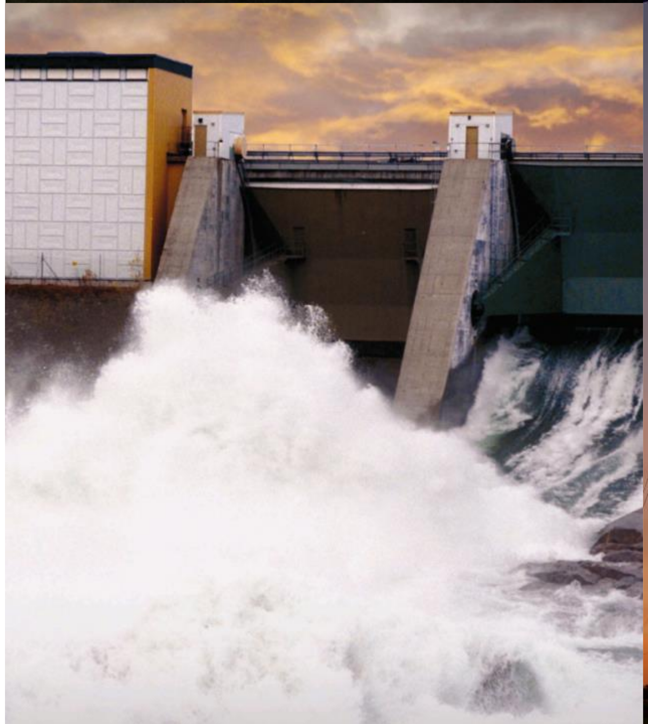
- Technical modelling of reactive power requirements under the FES 2025 scenarios. Key enabler to understand nature of requirements and provider effectiveness.
- Economic modelling based on results from technical modelling, feeding into the assessment of the market design and forming a view on the case for change.
- Technology research: Analysis of current & potential providers of services (incl. assumed capability for technology, typical size, and expected capex/opex).

Industry workshops

The project fed stakeholders' views directly in the design and assessment process. Five industry webinars were held to share initial findings and seek feedback.

- Webinar 1 & 2: Introduction to the project and project update
- Webinar 3: Market analysis workshop seeking views and feedback regarding the technology case studies
- Webinar 4: Shared initial findings on the building blocks and design options, seeking feedback on wider design topics, followed up by a questionnaire
- Webinar 5: Recap on market analysis, conclusions from DER participation study and technical analysis, and recommendations on the market design seeking feedback from participants on specific design features

Agenda



Key messages

Retiral of old plant providing services under the ORPS arrangements, in particular coal and in the future gas and nuclear means there is **reduced access** to **reliable reactive power** providers

Shifting economics of different technologies means new generators are not replacing 'like-for-like' **–** rapid increases in **embedded generation** and a shift towards **intermittent technologies** which are located increasingly far from demand for reactive services

Demand for reactive power services is **increasing –** changes to **network topology**, offtake at GSP to **DSO networks** (due to embedded generation) and **consumer behaviour** are all contributing to increasing demand for reactive power at the transmission network level

Spend on reactive power is **increasing** as accessing providers is becoming increasingly expensive, traditional ORPS providers are being driven 'out of merit' by new technologies, requiring synchronisation to access

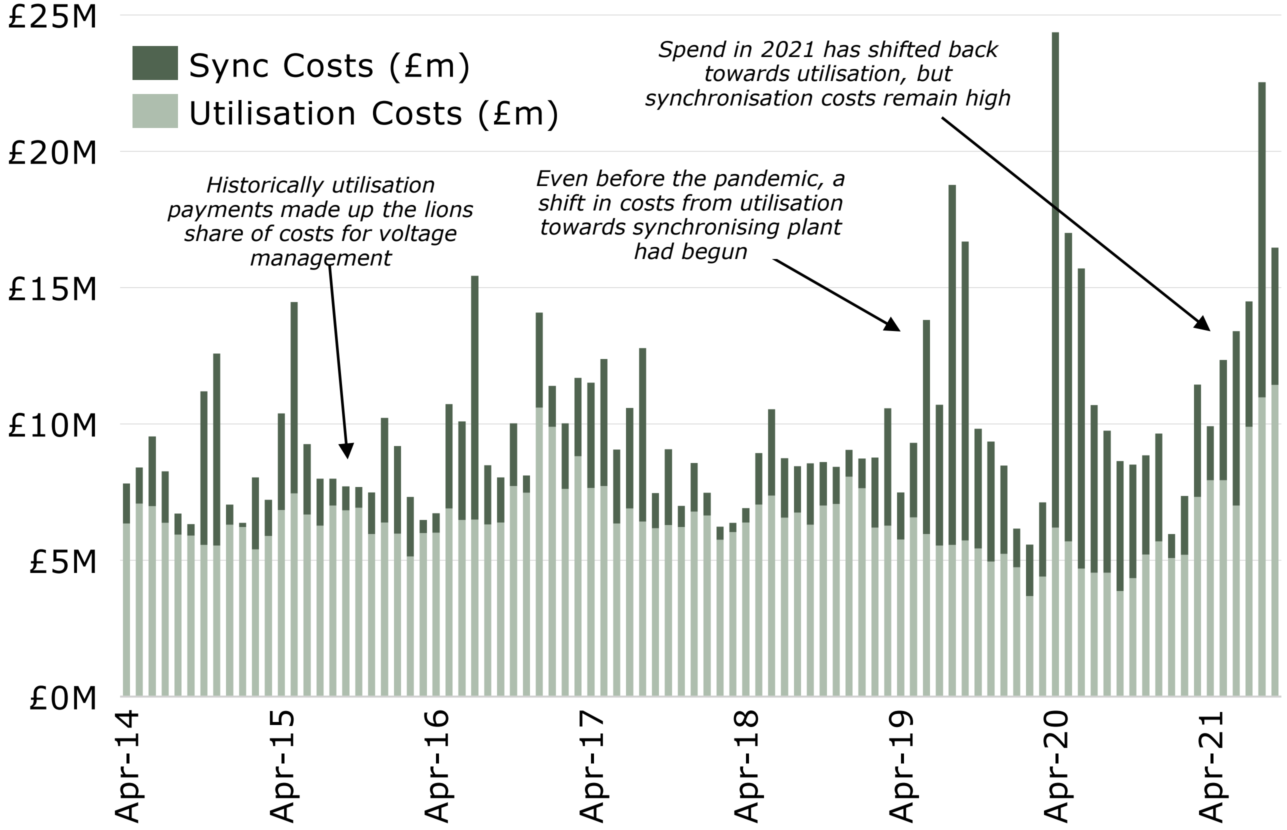
No enduring arrangements to drive **technical innovation** – no route to market for some solutions or **insufficient economic incentives/clarity over needs** to stimulate innovation

The balance between utilisation payments and payments to generators to position themselves to provide reactive power has shifted in recent years

VOLTAGE COSTS

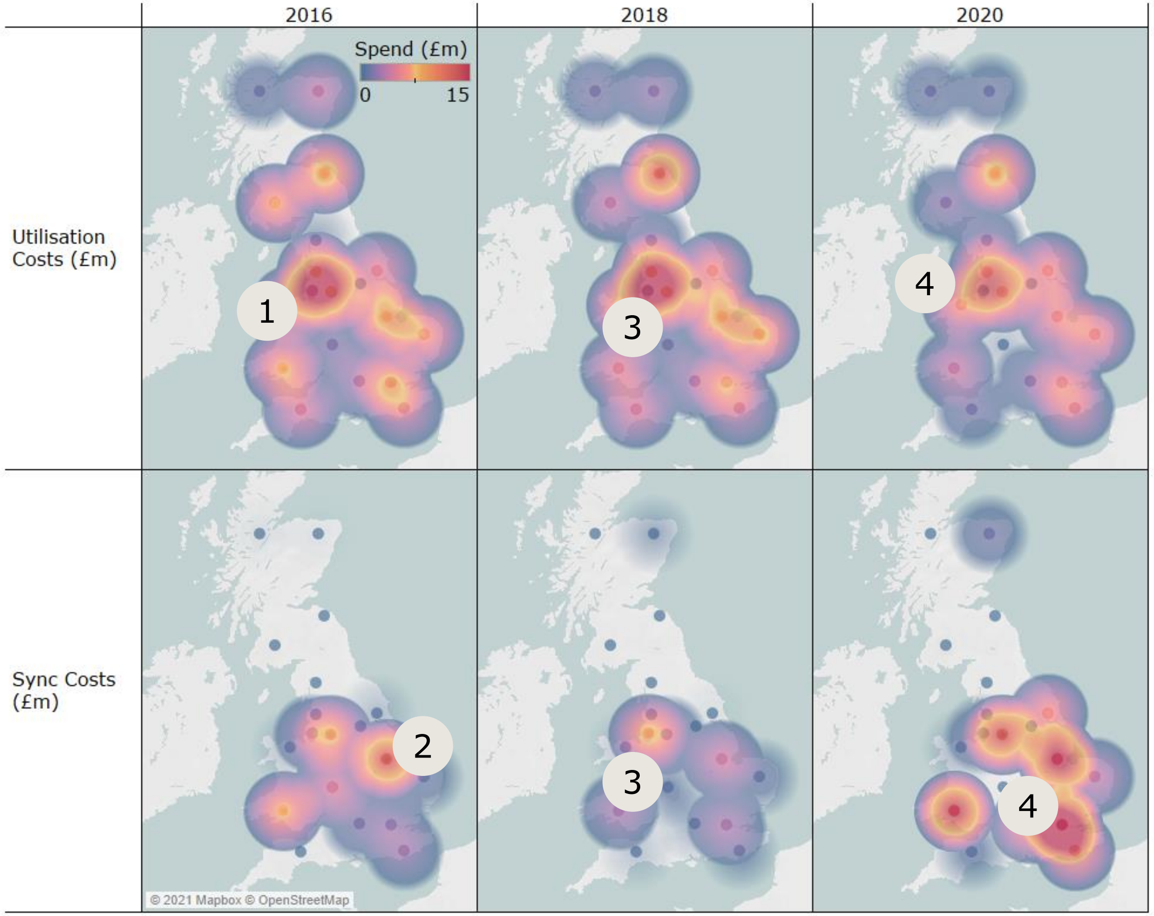
- Historically, utilisation payments were the largest contributing factor to voltage spend in Great Britain.
- In recent years, significant additional costs are being borne by the ESO (and ultimately customers) due to fundamental changes in the system.
- Thermal plant required to provide the service are increasingly being synchronised to access their reactive range:
  - this is driven partially by the increasing volumes of low-marginal cost generation such as wind and solar; and
  - partially due to the retiral of plant in strategically important locations on the network.
- Synchronisation costs are particularly high in spring/summer when lower demand results in less 'space' for thermal generator on the system.

MONTHLY VOLTAGE MANAGEMENT COSTS (£M, NOMINAL)



Recent spend for managing voltages commercially has shifted from utilisation of providers to payments to access their reactive range

REACTIVE SPEND BY VOLTAGE REGION (£M, NOMINAL)



REGIONAL SPENDING

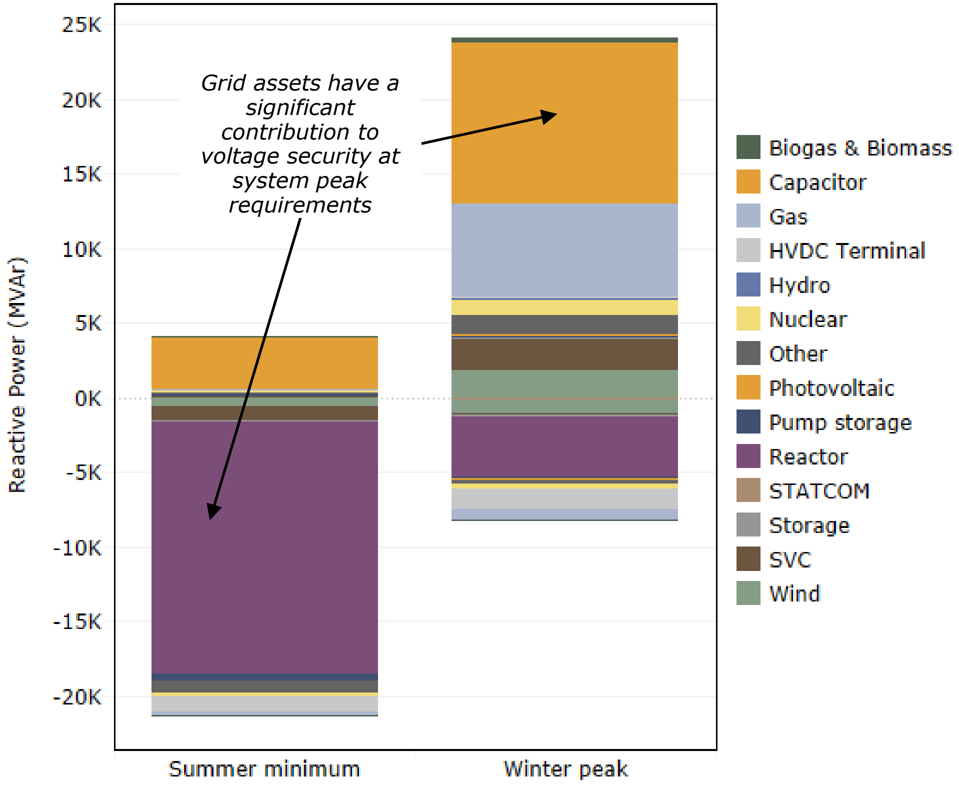
1. Historically, spend was primarily driven by utilisation, much of these costs being borne around the Mersey region.
2. Some synchronisation required contributed to total spend but this was limited to the East Midlands (and to a lesser extent Mersey regions).
3. In recent years, spending in the Mersey region has been persistently high for utilisation and synchronisation of providers to access reactive power services. The Pathfinder initiatives should help to alleviate some of these costs.
4. In 2020, the relativity between utilisation costs and synchronisation costs shifted for the first time. This was largely driven by demand reduction as the pandemic suppressed consumption, fewer thermal plant were synchronised at the market schedule stage to provide reactive power services and had to be accessed through the Balancing Mechanism to ensure system security.

Note in 2021/2022 costs have shifted back to utilisation as extremely high power prices have fed through into ORPS rates

nationalgridESO AFRY ÅF PÖYRY

Peak requirements for reactive power occur in opposite directions at different times of year

PEAK REQUIREMENTS BY TECHNOLOGY (MVAR, ETYS 2025/26, NATIONAL UTILISATION OF RP)



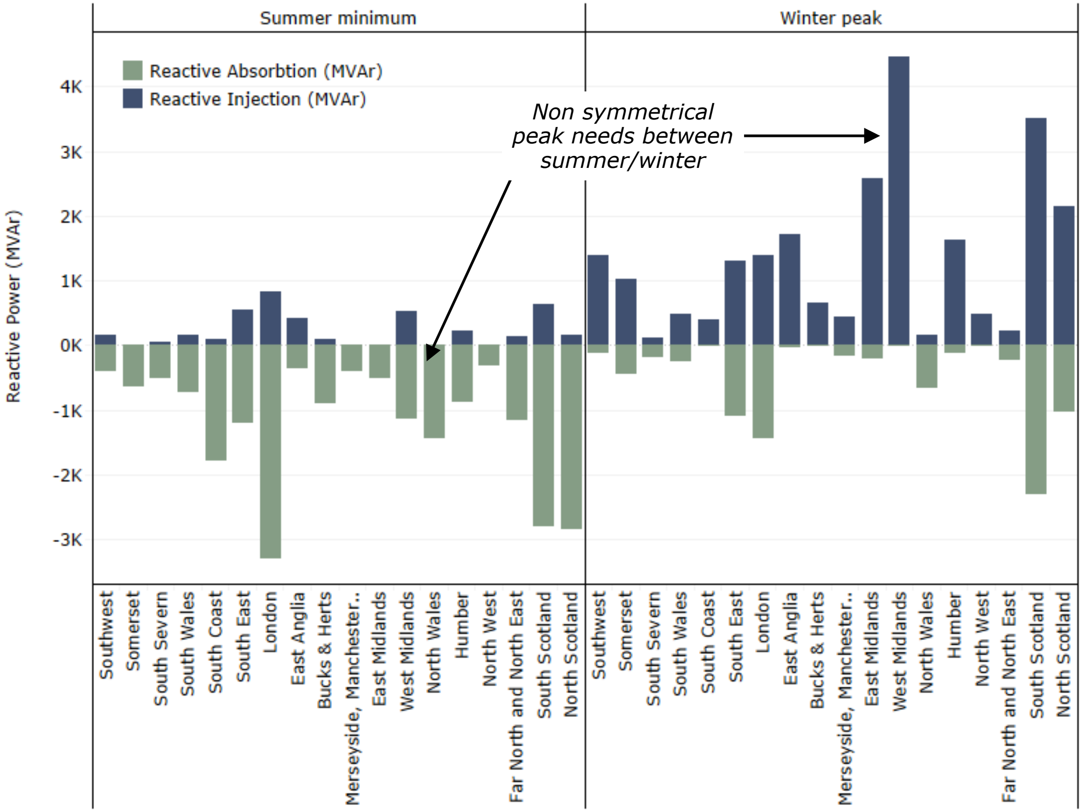
REACTIVE POWER NEEDS

- Summer minimum conditions tend to occur overnight, when generation from renewables is limited, demand is low and few thermal plant are synchronised.
- In summer minimum conditions, the transmission system itself is generating reactive power - the majority of reactive power needs are met by reactors, capable of absorbing reactive power with relatively low electrical losses.
- If current trends continue, additional reactors (or equivalently capable grid assets such as STATCOMs or SVCs) will be needed to ensure security at the summer minimum.
- The winter peak has the opposite trend, where reactive power must be injected into the grid to prevent voltages from falling.
- At the winter peak, more generation is available that is capable of providing voltage support than is available at the summer minimum.

Notes: Summer minimum occurring in Aug 2025 and Winter peak occurring in Dec 2025), snapshot single point in time

Reactive power needs vary significantly by location, and requirements are non-symmetrical within regions

REGIONAL REACTIVE POWER NEEDS (MVAR, ETYS 2025/26)



REGIONAL DIFFERENTIATION

- Between regions, reactive power provision for both the summer minimum and winter peak vary considerably with a strong need for reactive absorption at summer minimum and a high requirement for injection at winter peak.
- It should be noted that these requirements are also non-symmetrical (e.g. Midlands regions) – it may be that capability (MVAr) requirements are higher in one direction than in the other (e.g. significantly higher peak requirement for reactive injection than absorption in the midlands regions).
  - As a result of this, it is likely that procurement volumes for upwards/downwards services will only have a certain volume of symmetrical requirements, with excess procured in a single direction.
  - This could have implications for new build technical solutions e.g. SVCs (bi-directional) vs. capacitors (single direction) which differ in cost.

Note: There are also differences in reactive power needs within individual aggregated zones listed here

Reactive power peak requirements are overwhelmingly met by reactors in the summer – in the winter, plant is synchronised and contributing

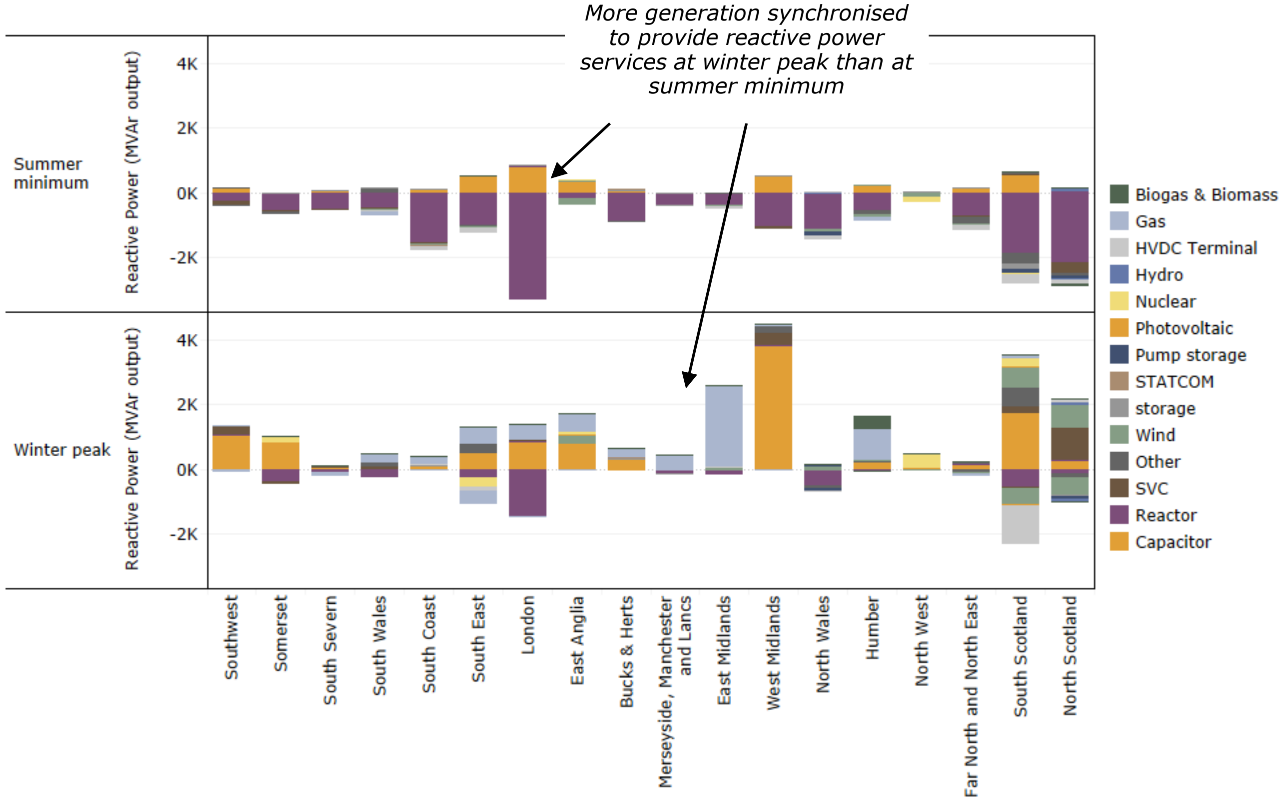
SUMMER MINIMUM

- CCGTs provide little contribution at summer minimum, as they are not generating (a pre-requisite for providing support).
- Wind output is also low, providing little support for reactive power needs.
- In general, technologies which require significant MW output to provide reactive power will struggle to contribute to summer minimum requirements.

WINTER PEAK

- Here, there is significantly more plant synchronised to provide voltage support, as higher demand results in more 'room' on the system.
- Capacitors and SVCs still contribute to a significant proportion of reactive power needs (more than half of the total requirement).
- As gas plant begin to retire, winter peak voltage support will become more challenging – relying on new and more innovative solutions.

PEAK REQUIREMENTS BY TECHNOLOGY (MVAR, ETYS 2025/26)



Notes: There are also differences in reactive power needs within individual aggregated zones listed here. Chart shows the provision of reactive power in peak/minimum conditions as opposed to actions taken to access reactive power range.

Agenda

Key messages

- Reactive power **demand and costs have increased** in recent years, whilst **legacy providers** (e.g. coal, old CCGTs) which have traditionally been used to manage voltage issues have begun to **retire** – we are expecting this **trend to continue** under existing arrangements

- Current reactive arrangements are **fragmented**, with a range of procurement routes to address **specific challenges**

- Reactive power is provided by both **commercial** and **regulated assets**, ESO is particularly reliant on the latter in low power flow situations – as needs are growing, new investment will be required in reactive power assets

- **Different technologies** face different **cost structures** – there may exist significant **opportunity costs** associated with accessing increased reactive ranges for some commercial providers

- Regulated assets can still offer **value for consumers**, even in the presence of a competitive market

- Commercial assets and regulated solutions are inherently different – assessing on a 'like-for-like' basis is **challenging**

Key recommendations

- Due to **increasing demand** for reactive power and expected future challenges, there is a need to **improve reactive arrangements** to ensure value for consumers in the long term
- **Consolidating arrangements** in a way that all challenges can be addressed through a coherent unified mechanism would **reduce complexity** for both ESO and providers
- With **legacy providers** beginning to **retire**, there will be the need for **additional investment** – making the right investment choices is especially crucial whilst the **system is in transition** towards a low-carbon future
- Market arrangements will need to facilitate a wide range of providers with **diverse cost structures** to **maximise competition** – long term commitments to facilitate suitable new investment and shorter term commitments for providers with low availability certainty or volatile variable/opportunity costs of provision
- Regulated assets should be assessed against commercial solutions to **maximise value for consumers**
- **Further work** should be done with TOs and Ofgem to **align on an enduring set of principles** for assessment of regulated assets against commercial solutions

MARKET ANALYSIS

There are a number of key routes to access for reactive power services at the ESO's disposal

Price basis	Route	Description
Regulated price	**Network assets**	Network assets are one of the primary tools for managing system voltage, the three most widespread technologies are capacitors, reactors, and SVCs. These assets are typically instructed/used first (before ORPS providers) and costs are recovered by providers through system losses and RAB (of the Transmission Owner).
Regulated price	**ORPS**	This is the primary route to procure services from large generators connected to the transmission network where participants are obliged to provide reactive power services within a fixed range and paid a regulated price. Importantly whilst not dispatching they are not obliged to provide the service and so may be instructed through the Balancing Mechanism or Schedule 7a trades.
Part regulated price	**Voltage contracts**	These are a derivative of ORPS, where providers are paid the ORPS rate but guarantee availability to provide the service (by contracting with a provider at a pre-agreed price to be operating at their SEL). Providers are paid ORPS rates for their reactive power and a separate payment for their availability (can be market index based or a fixed availability price).
Competitively determined price	**Pathfinder contracts**	NGESO has procured long term contracts for reactive power provision in Merseyside and in the Pennines region. Long term contracts give access to high availability solutions for reactive power that are paid an availability fee.

Key question: Do providers exist outside of these arrangements that NGESO cannot currently access?

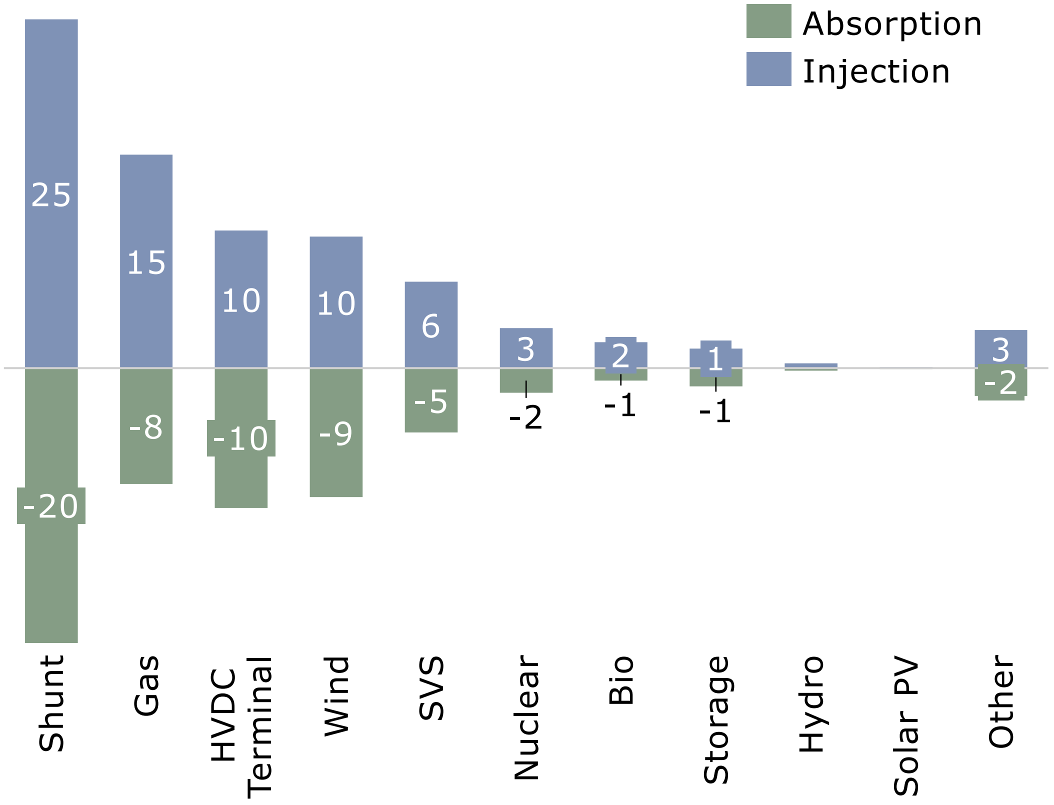
Cost incentive to avoid provision	**Distribution arrangements**	The distribution network is not inherently a route to access reactive power but transfers across the interface between DSO region and TO assets affect the voltages on the system to some degree. Distribution connected assets are charged for reactive power outside a given power factor range, in the HV and LV networks this is explicit, within the EHV network this can be implicit in site specific charges. Furthermore a power factor closer to unity will reduce network capacity charges (levied on a p/kVA/day basis). There have been innovative projects running such as NGESO's Power Potential as well as SPENs tenders through the Piclo Flex platform to procure reactive power.

Note: Some other 'one-off' arrangements exist, ORPS = 'Obligatory Reactive Power Service', SEL = 'Stable Export Limit', ERPS excluded as not used by market participants today

MARKET ANALYSIS

Network assets & RES play an important role, but gas-fired generators are expected to still be required to ensure overall system security in the near term

GVAR CAPABILITY IN GB (ETYS 2025/26)



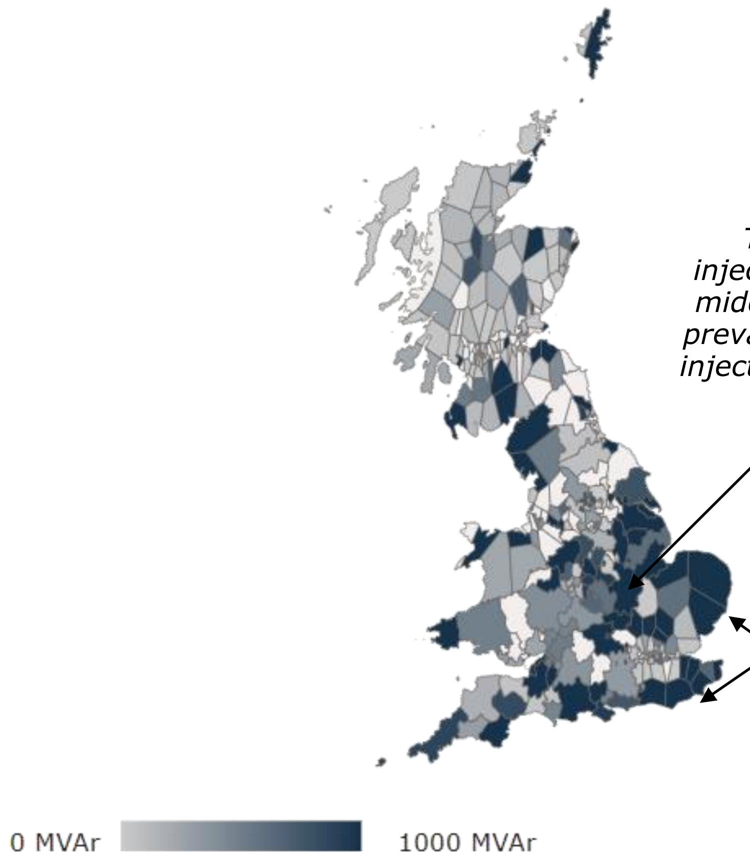
- TO network assets have high availability and are the largest source of reactive power on the network today with over 50GVAr of assets on the system (reactors + capacitors + SVCs + STATCOMs).
- CCGTs also offer substantial capability and can be instructed on to access MVArs, though other plant must be turned down to ensure demand is not exceeded – this can be extremely costly and in summer minimum conditions.
- The total capability that can be offered by wind is large, though weather dependence means availability is lower than for other asset classes.
- HVDC connections play an important role today, in the future capability will increase through a combination of interconnectors, TO HVDC connections, and OFTO assets (for HVDC connected offshore wind).
- Reactive power does not travel through DC connections, however onshore reactive compensation equipment associated with HVDC infrastructure will be accessible to ESO.
- Many providers that offer reactive services are low carbon, however the availability of low carbon reactive providers is uneven across the country (with CCGTs dominating provision in the Midlands and South East where reactive power absorption needs are highest).

Notes: Excludes embedded generation, Shunts=reactors/capacitors (single directional grid assets), SVS=STATCOMs + SVCs (bi-directional grid assets)

MARKET ANALYSIS

AFRY has produced a heatmap of expected MVAr capability by GSP for ESO using ETYS data

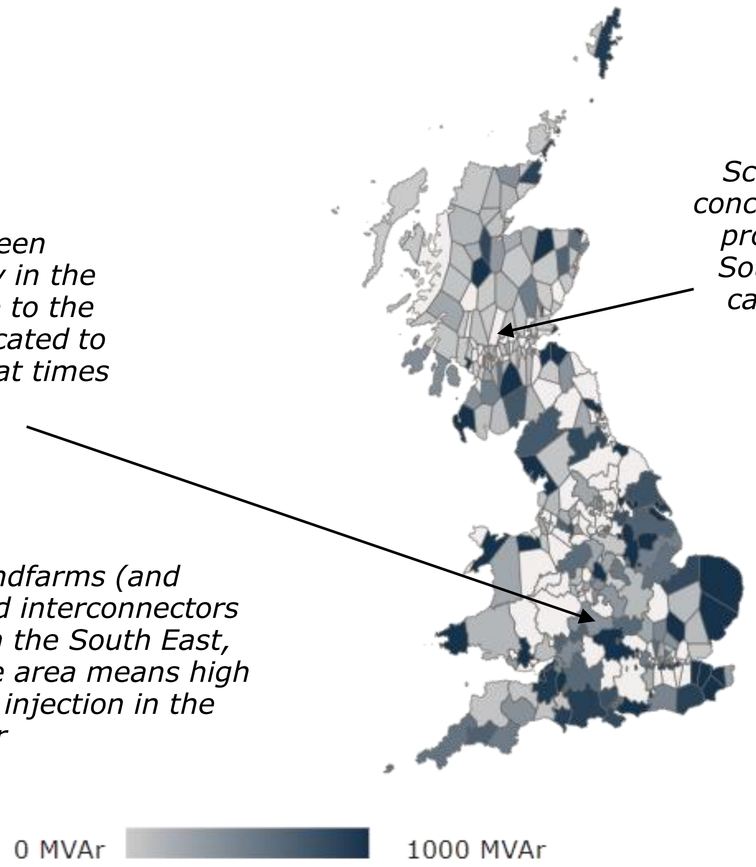
MVAR CAPABILITY FOR INJECTION (2025/26)



There is a mismatch between injection/absorption capability in the middle of England, this is due to the prevalence of grid assets dedicated to injection, supporting voltages at times of peak demand

Large offshore windfarms (and associated OFTOs) and interconnectors increases capability in the South East, high power flows in the area means high demand for reactive injection in the winter

MVAR CAPABILITY FOR ABSORPTION (2025/26)

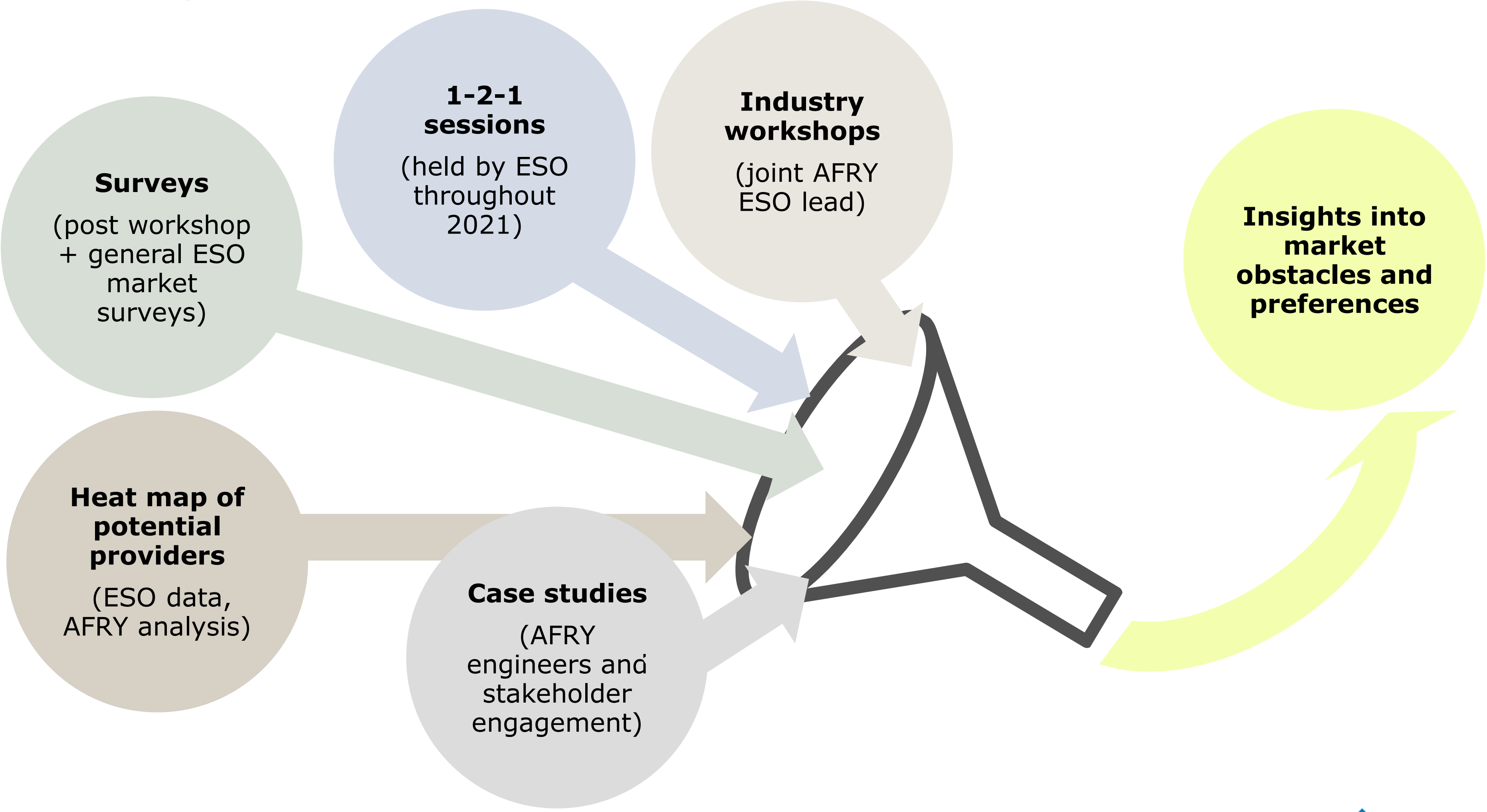


Scotland has a lower concentration of reactive providers than in the South but substantial capability still exists

Notes: Injection contributes to increasing/supporting voltages and absorption is utilised for managing high voltages

MARKET ANALYSIS

We have relied on a large range of sources to understand challenges faced by potential providers



MARKET ANALYSIS

Most commercial barriers are related to uncertainty and variability

Technology affected	Key blocker	Key enabler	Preferred solution
Batteries/converter connected storage	High opportunity costs in valuable/high demand periods	Need to allow plant to participate when service is most valuable	**Short term market**
Variable converter connected technologies (e.g. wind)	Low availability certainty	Need to allow plant to participate at point where availability becomes more visible/certain	**Short term market**
Traditional thermal providers	High and uncertain fuel cost + uncertain requirement (difficult to hedge)	Need to allow plant to participate when costs are known and when requirements are highest	**Short term market**
All capacity	Additional Capex and Opex associated with higher MVA rating of equipment (if relevant)	If there is a low incremental cost, but long term commitment is inappropriate need to allow some short-term revenue to encourage deployment	**Short term market**
All capacity	Complex relationship between power factor, MW output, and heat losses (additional costs)	Need to give the opportunity for participants to bid portions of capacity to reflect non-linear cost	**ST market with availability and utilisation fee (or volume visibility)**
All capacity	Poor visibility over dispatch commitments	Dispatch risk should sit with ESO (to the extent possible), availability only fee requires participant to forecast dispatch and 'price in' dispatch costs	**Both availability and utilisation fee (or volume visibility/cap)**

MARKET ANALYSIS

It is desirable to remove blockers to maximise participation

Technology affected	Reason for facilitation in market	Volume[1]	Reliability[2]	Cost[3]
Batteries/converter connected storage	**High opportunity cost** (when MVAr requirements are high for both absorption and injection): Potentially substantial additional capacity available in periods of system stress.	Medium	High	High
Variable converter connected technologies (e.g. wind)	**Low availability certainty:** When demand is low and output from variable renewables is also low, providers that are technically configured to do so can offer substantial additional capability for absorption that cannot currently be accessed via ORPS at relatively low cost – however, as this is unpredictable it is difficult to structure a reliable long term contract around this.	High	Low	Low
Traditional thermal providers	**High and uncertain fuel cost and requirement:** There is substantial capacity that can provide reactive power today and there is a desire to incentivise providers without having to instruct in the Balancing Mechanism.	High	High	High
All capacity	**Additional Capex/Opex for MVA capacity:** When designing new capacity, in particular new variable converter connected technologies, it is desirable to encourage maximisation of potential asset capacity at the initial design stage. A price signal can encourage this behaviour.	Unknown (future)	-	-
	Complex relationship between MW/MVAr/Cost: Many providers will not have visibility of their dispatch schedule in investment timeframes, so design arrangements should encourage efficient use of assets by maximising the capacity available at the time of need, not imposing arbitrary or artificial limitations.	High	-	-
	Poor visibility of dispatch commitments: It is impractical for most providers to forecast their dispatch of reactive power. As this is much more visible to ESO, the risk should lie with ESO to maximise participation and encourage cost reflective bidding (avoiding risk premia where possible).	High	-	-

Notes: [1]Potential system-wide MVAr capability [2]Can be reliably accessed when needed [3]Represents cost of potential solution to ESO at time of need

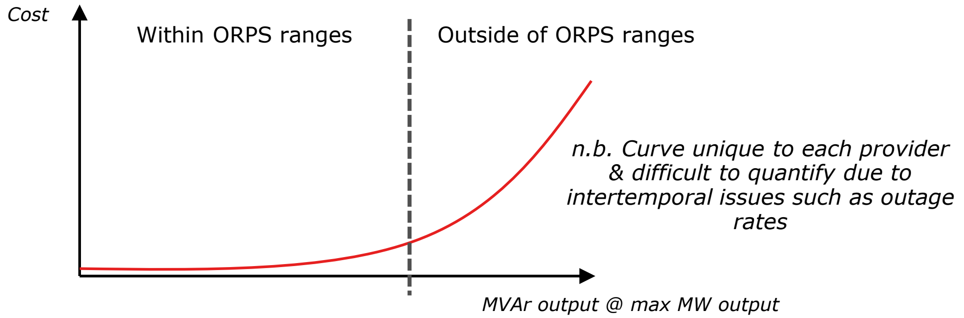
MARKET ANALYSIS

A two part pricing mechanism may be desirable, but only if utilisation costs are material – there are many dedicated assets for which this is not the case

Availability costs	Utilisation costs
Availability costs, are costs that are incurred for simply making an asset available to provide reactive power (before any delivery of reactive power). As a simple example, this could be the synchronisation cost of a CCGT. In this context, we include the cost of existing (i.e. capacity cost which can include fixed operational costs & investment costs), however, this could equally be a separate cost item.	There are two core costs of being utilised, which both manifest as a result of heat: efficiency losses (additional energy costs) and wear on equipment (additional outages and Opex). These are dependent not only on the reactive dispatch instruction, but also the MW output of the equipment making them difficult to predict and manage when power factors deviate significantly from unity.

Capex/Opex	Building new assets/maintaining old assets
Synch costs	Fuel costs, start costs, variable maintenance costs & other consumables
Opportunity costs	Foregone revenue from other activities

Variable cost of component heating



nationalgridESO AFRY ÅF PÖYRY

MARKET ANALYSIS

Transmission Owner assets are bound by licence obligations and are remunerated through their Regulated Asset Base

Current situation

Transmission Owner (TO) assets for reactive power services have historically been deployed out of the necessity for compliance with licence obligations. Historically, if a potential failure to secure the system is identified, TOs would apply to build assets under their RAB to compensate for expected issues forecast to arise from a deficit of reactive capability. As reactive capability was a Grid Code requirement with limited signals to improve capability, investment in assets was primarily an activity undertaken by the TO.

Ultimately under any market arrangement, owners and operators of regulated assets including (but not limited to) TOs will need to ensure they comply with their licence obligations.

Treatment of existing assets

Existing TO assets are remunerated outside of the reactive market, fundamentally:

- If TO assets are being remunerated sufficiently elsewhere, they should not be eligible to participate in the market (and receive windfall gains).
    - There may be concerns that increased utilisation of TO assets could increase costs for TO assets, however, these costs should have been comprehensively considered by TOs when submitting costs to Ofgem for approval pre-asset commissioning.
    - An opportunity to account for utilisation forecast error should be considered at that time.
    - Some key utilisation costs (e.g. energy costs) are broadly treated as a passthrough regardless.
- We are not considering existing TO assets within their RAB period for inclusion in any markets (short or long term).
- Our market design does include TO assets as a counterfactual for procurement purposes (appetite to pay for new providers).

TO assets outside of their RAB period should be considered as a potential solution if economically efficient. This issue warrants further investigation.

MARKET ANALYSIS

TO assets can offer opportunities in the interest of consumers, but direct comparison with commercial solutions will be imperfect

Reason for facilitation

TO assets costs can be competitive with commercial providers, we would therefore want to include them in a market arrangement. TO asset participation in a market could theoretically be: (a) direct, whereby they offer a competitive 'bid' into the market; or indirect, whereby the cost of the solution is independently evaluated and assessed against commercial offers.

Opportunities and challenges

Maximising tools to ESO

One of the key opportunities offered by the implementation of a market (Long Term, if not Short Term) is to evaluate alternatives to regulated TO investment, to ensure that the best interests of consumers are met in the provision of stability services.

Exposure to competition

Note that in the long term, economic theory suggests that the efficiency gains of competition (incentives for innovation and cost reduction) outweigh the inefficiencies (duplication, etc.). Therefore, the existence of a competitive alternative to a regulated investment, making a 'contestable market', is likely to be positive for consumers even if the regulated investment proves to be the winner.

Neutrality challenges

The evaluation between regulated and non-regulated assets requires a level playing field as far as is possible. There are many reasons why a perfectly level playing field may not be possible, but we should look at the potential reasons for bias to ensure that the evaluation can be as neutral as possible.

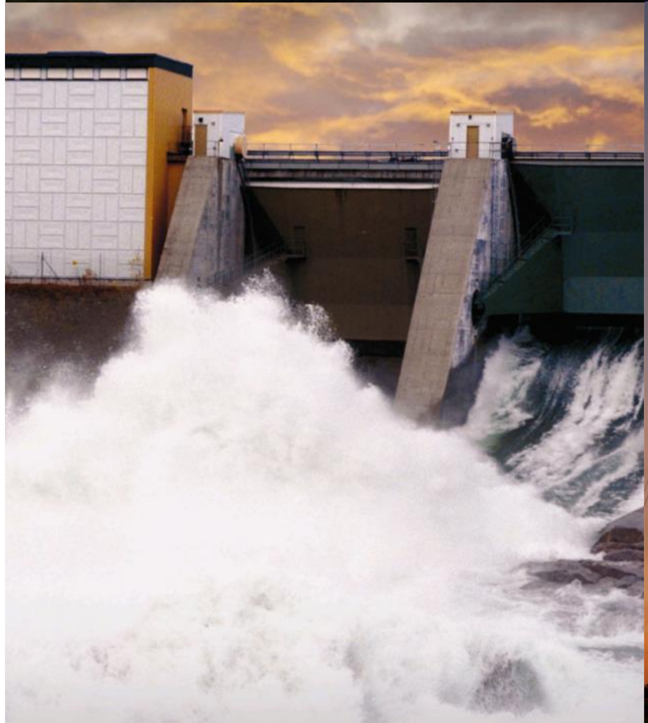
MARKET ANALYSIS

Difficulties arise assessing regulated solutions against commercial providers

Asset lifetime	– Regulated asset lifetime exceeds expected commercial contract duration. Current process depreciates asset over contract duration to reflect ESO needs. – *Further work needed to explore residual value.*
Cost of capital	– Cost of capital artificially low, partially due to risk being underwritten by consumer. – *Further work needed to explore whether realistic to adjust cost of capital when assessing cost of solution – unlikely this is plausible to easily address with a consensus solution.*
Obligations and penalties	– Obligations not uniform between TO and commercial contract. – *Adjust assessment to reflect additional costs and benefits (e.g. availability obligations).*
Energy costs	– TO asset energy consumption included in losses. – *Adjust assessment to reflect cost of losses.*
Preferential access to sites	– TO will have preferential access to connections close to crucial grid infrastructure. – *Open up connections to competition.*
Preferential access to information	– TO has detailed knowledge and model of own network. – *Transparency in data & open up connections to competition.*

Agenda






Key messages

There is **additional reactive capability** embedded in the distribution networks that could help to resolve **transmission level** voltage issues

DSOs must manage their **own system voltages** and keep them **within safe limits**, but DSOs have **fewer tools** to manage voltages than the ESO

Voltages at the distribution network level are primarily managed through **tap changing** and distribution networks tend to run at the higher end of the voltage range to minimise losses which can have **adverse effects on the transmission network**

Potential providers at the distribution can be exposed to **increased costs** due to their behaviour with respect to reactive power, at best **disincentivising service provision** and at worst creating a **value passthrough** from ESO to DSO for services

Due to legacy behaviour and rules around reactive power for providers in the distribution network, it is unclear how much reactive can be **transferred to the transmission network effectively**

Key recommendations

Additional capability from the distribution network **should be facilitated** if **practical/cost effective** to do so

Where there are issues of **conflict** between the distribution network and transmission network, **DSO instructions** should take **primacy** due to there being **fewer tools** available to DSOs to manage local system issues than available for ESO

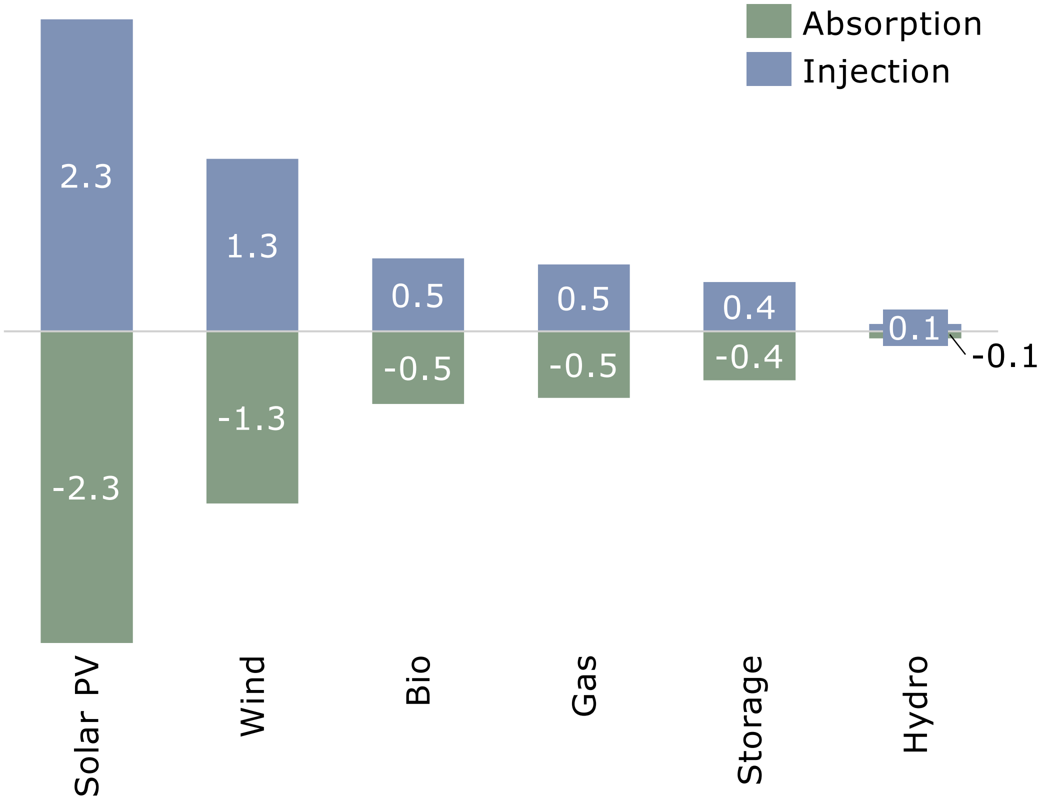
Historically, losses were a **financial incentive** under the DSO RIIO framework, but this is now moving to a reputational incentive – behaviour of DSO network behaviour should be **monitored** to ensure that behaviour is not causing **net-adverse effects on consumers** due to offloading reactive issues to the transmission network

Distribution charging arrangements for reactive should be **reviewed**, and where appropriate, providers' **exposure** to these costs when providing reactive services **should be revised/removed**

DSOs will need to **re-run network studies** to understand **limitations**, and potentially **modify connection agreements** to allow providers on the distribution network to provide reactive power services

There is additional capability that can potentially be accessed from the distribution network

POTENTIAL GVAR CAPABILITY FOR SMALL DER (ETYS 2025/26)



- According to ESO data, there is potentially 10GVAr (injection + absorption) of additional capability embedded within the distribution network from small DER that could be used to help resolve voltage issues.
- Most of this additional capability is from smaller scale wind or solar generators.
- Increasing exploitation of existing assets on the system could bring cost savings for consumers through increased competition.
- Much of this capability is in the south and south-east (where solar resource is strongest), an area of the network that suffers with extreme voltage challenges and high associated voltage management costs.

AFRY & ESO have run a separate workstream to look at the challenges for enabling DER to participate in a potential reactive power market.

Notes: Assumes symmetrical capability on average, potential capability based on case study information

dso current practice for reactive power management results in problems at the transmission network – however innovative solutions are emerging

1. DSOs are obligated to keep voltages within limits governed by their licence conditions.

2. Changing utilisation of network assets across both the distribution and transmission networks has resulted in additional reactive compensation needs, partially due to the way volts are managed on the distribution network.

3. The primary method for DSOs to manage voltages on their system is through tap changing.

4. Tap changing reduces/increases number of windings in a transformer, which affects the voltages at either side of the transformer (compared to if a fixed ratio was always employed).

5. The problem of 'high volts' (voltages towards to upper limit of equipment rating, the most prevalent issue) is passed to the transmission network as tap changing configurations and a lack of other reactive compensation equipment in the distribution network mean DSOs have limited routes to keep voltages within limits.

6. To help overcome these challenges, DSOs have been exploring innovative solutions to help support the overall system, such as procurement of reactive power to manage their own networks, and the Power Potential project aimed at providing reactive power to support transmission network issues.

A range of technical, commercial and regulatory blockers affecting service provision have been identified

#	Blocker	Description	Tech	Comm	Reg
1	**Distribution system stability**	– Power quality on distribution systems needs to be maintained to defined standards to maintain their stability, potentially limiting capability	☑		☑
2	**Distribution system losses**	– Provision of reactive power affects levels of distribution system losses, which creates a disincentive to service provision		☑	☑
3	**Distribution charging**	– Reactive power charges within distribution charging arrangements may discourage service provision		☑	☑
4	**Connection agreement power factors**	– Connection arrangements specify requirements to maintain power factors to defined standards, potentially limiting capability	☑		☑
5	**Non-firm connection limitations**	– Sites with non-firm/flexible connections may not be able to provide reactive services reliably at all times	☑	☑	
6	**System studies**	– Assessing feasibility and impacts of potential service provision requires system studies, with associated cost and resourcing overheads to recover		☑	☑
7	**ESO / DSO conflict potential**	– Scope for service provision to both ESO and DSO creates the potential for conflicts	☑	☑	☑

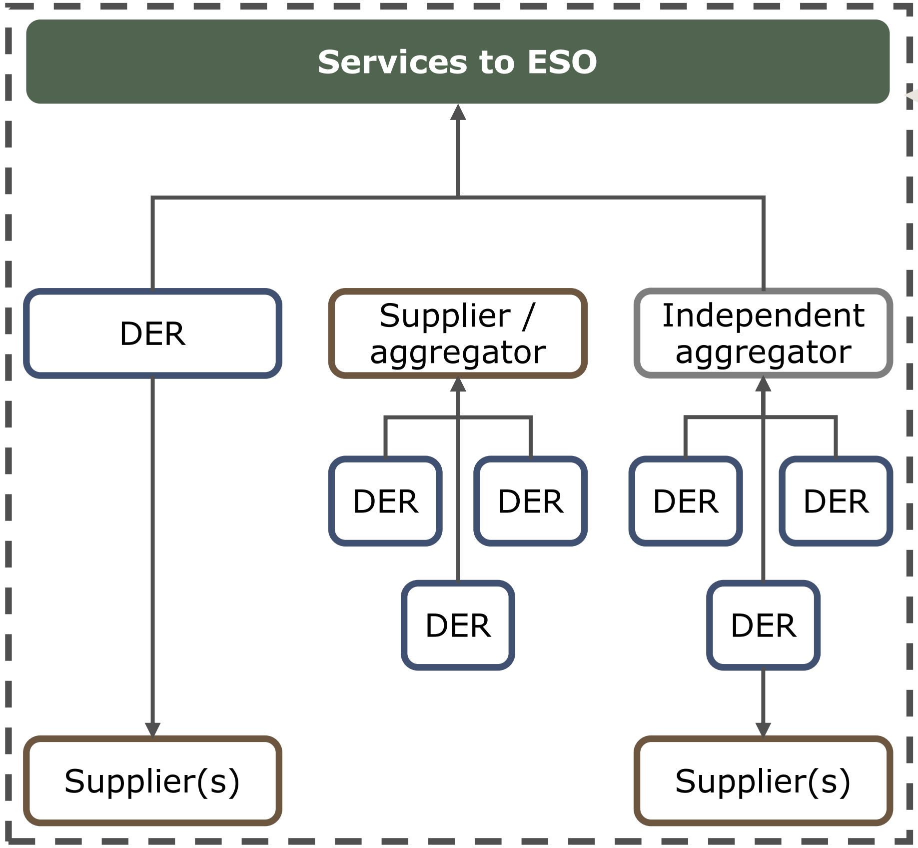
nationalgridESO AFRY ÅF PÖYRY

Possible ways forward exist to allow for routes for overcoming barriers to be considered, although many are complex

Relative ease (provisional)

1	**Distribution system stability**	– Technical review of standards specified in ESQCR and Distribution Code to identify scope for amendment. Given importance of ensuring security, risk aversion may mean that the prospect for change is limited.
2	**Distribution system losses**	– Issue may be expected to diminish under RIIO-ED2 given the proposed removal of financial incentive around losses. However, reputational focus still expected. As part of losses strategy, DSOs can make case for the value of trading-off increased losses and provision of reactive services, but this may be complex.
3	**Distribution charging**	– Review of charging methodologies to identify potential alternative approaches or parameters to apply in respect of treatment of power factor to support efficient provision of reactive power services within cost-reflective charges. Could be effort intensive and complex, with scope for distributional impacts on users.
4	**Connection agreement power factors**	– Technical review of standards specified in connection terms to identify scope for amendment to support efficiency while maintaining stability/security. If potential benefits available, need cost-benefit analysis to assess merits of rollout. Could be effort intensive and complex, with scope for distributional impacts on users.
5	**Non-firm connection limitations**	– Non-firm connections provide valuable flexibility for system management and so are expected to remain. Inclusion of a non-firm reactive power product in ESO design may allow for provision by parties with non-firm connections.
6	**System studies**	– Scope for specific provisions to cover system study costs/resources under RIIO-ED2 (although final business plans now submitted, so if not covered already, it will be difficult to achieve for RIIO-ED2).
7	**ESO / DSO conflict potential**	– Requires ongoing consideration of appropriate frameworks for coordination. This is a long-standing issue and difficult to resolve. Models such as Power Potential offer a possible solution, but it requires broad consensus and effort to rollout.

Increased use of DER for ESO service provision necessitates a more active role for the DSO to mitigate distribution system issues and potential conflicts

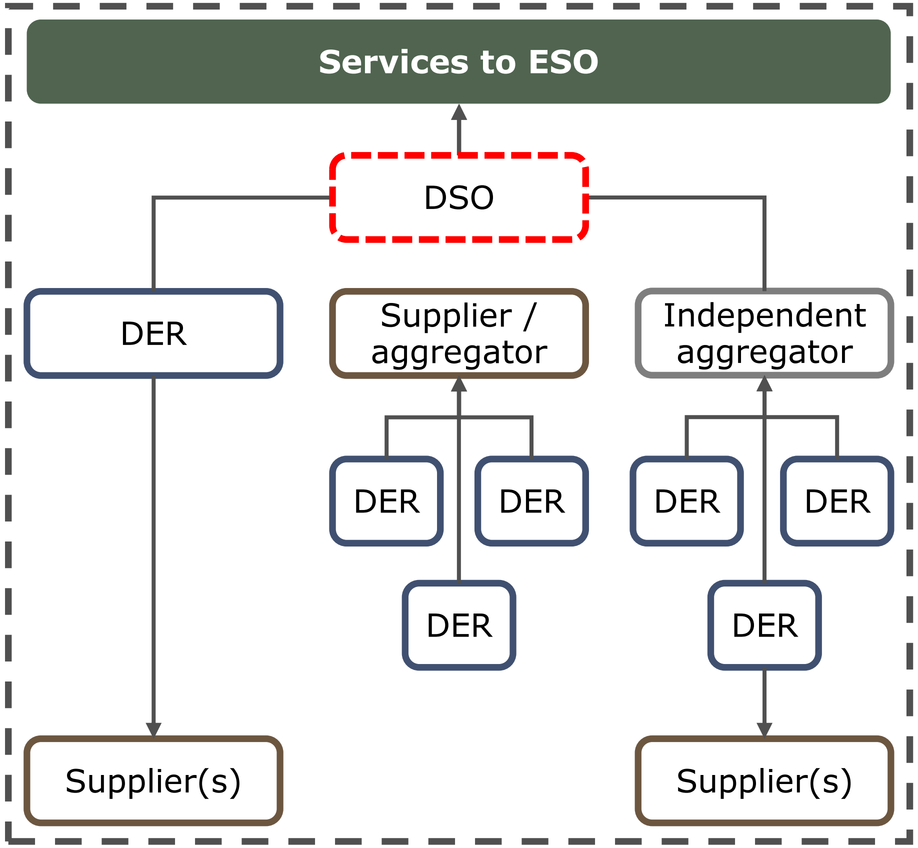


FROM:

To date, contracting approach for service provision from DER has not allowed for or included much coordination between ESO and DSO

TO:

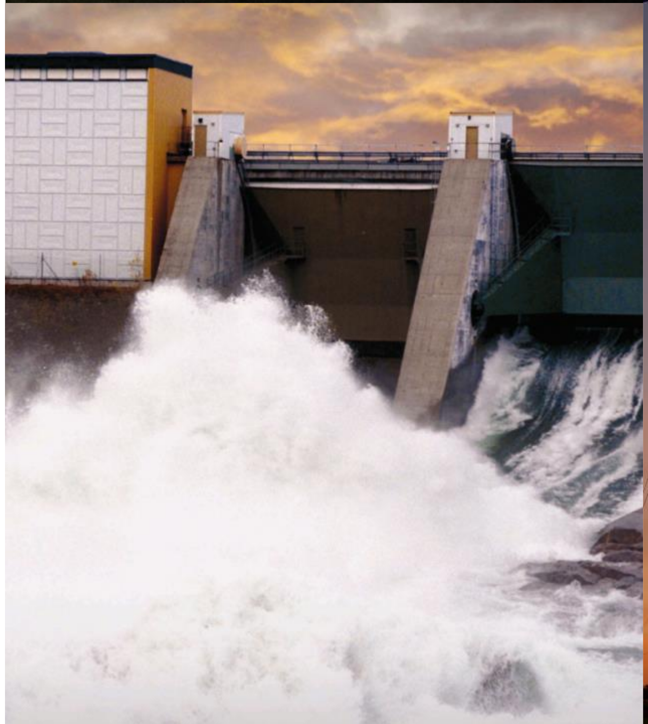
As DER and its usefulness to ESO increases, the DSO is expected to need a greater role. What type of role will DSO have?



Source: Adapted from Energy Networks Association

Agenda






Key messages

1	Reactive power market setup should be **nodal** (bottom-up), not zonal (top-down)
2	"Reach" of reactive power providers can be measured through **effectiveness.**
3	Assessment of effectiveness therefore enables **competition** between providers, adjusting for the value they bring to the system.
4	Some reactive power providing **transmission owner (TO) assets will still be required in practice**.

Conclusions and recommendations

✓	A proof-of-concept implementation of a nodal reactive power market has been provided.
✓	Methods to determine needs and effectiveness have been developed, implemented and tested.
✓	A high degree of automation has been achieved.
✓	The method covers the four envisaged products: • pre-fault / post-fault, absorption / injection
✓	ESO will carry out further simplifications and refinement for practical applicability • already considered in the demo implementation • to be further analysed moving forward.

Executive summary of the approach

Nodal needs and nodal effectiveness are calculated from AC power flow model of entire transmission system.

- Power flow and contingency analysis are used to determine the reactive power needs.
- Sensitivity analysis is used to determine effectiveness matrices.

“Nodal effectiveness” means that provider effectiveness across the system is a matrix.

- Use the same effectiveness for absorption/injection (to be monitored), but different effectiveness for pre-/post-fault products.
- Aggregation of post-fault (per fault) effectiveness is required to manage complexity and transparency (communication and procurement).

Effectiveness must be adapted over time to changes in grid topology.

Product descriptions

The project team are proposing 4 products include pre/post step change for both reactive power injection and absorption.

	Pre-fault (step change)		Post-fault (step change)
Absorption	– Allows pre-fault, steady state voltages to be maintained within SQSS limits – Utilised primarily when power system flows are low	**Absorption**	– Allows voltages steps and steady state voltages to be maintained within SQSS limits following an event or operational switching – Utilised primarily when parts of the network from where pre-fault absorption providers were dispatching become isolated or if high gain circuits are switched in
Injection	– Allows pre-fault, steady state voltages to be maintained within SQSS limits – Utilised primarily when power system flows are high	**Injection**	– Allows voltages steps and steady state voltages to be maintained within SQSS limits following an event or operational switching – Utilised only when a step change occurs either after a fault/unplanned outage or after operational switching to support voltage levels

Defining the Demand – Overview of the Problem

Technical Background Questions

What is needed when and where?

- Reactive power needs correspond to voltage control requirement: The voltage at all transmission system nodes must remain within SQSS limits before and after any credible contingency.

What factors influence the reactive power needs?

- State of the grid
- generation and demand distribution patterns/variability and resulting power flows
- contingency cases

Who can (technically) provide the reactive power?

- Shunt reactors or capacitors
- STATCOMs, SVCs, synchronous condensers
- Generators and storage: synchronous machines and inverter-based resources

Goals, Constraints and Non-Goals

Goals

- The methodology should provide a workable solution to an optimisation problem – How to allocate existing and new reactive power providers through a mechanism that results in lowest system cost while meeting all needs.

Constraints

- Allocated reactive power providers must be sufficient to ensure that voltage control requirements (pre- and post-contingency) are met at all times.
- Reactive power providers must be enabled to compete on fair and equal terms towards supplying the reactive power demand.

Non-goals

- This work is not meant to replace existing methods used by NGESO and TOs to determine where voltage issues exist, and where transmission owners need their own assets to resolve them.

Defining the Demand – Top-down Zoning Issues

Zoning

Assumptions

- Reactive power providers can be grouped according to where they are technically able to contribute to supplying the reactive power demand.
- Conversely, for a given provider location, transmission nodes can be grouped according to where the provider can effectively contribute.
- If we can pre-determine these grouping structures, we can use them to aggregate, communicate, and optimize the reactive power allocation between the providers. Can we?

Investigation

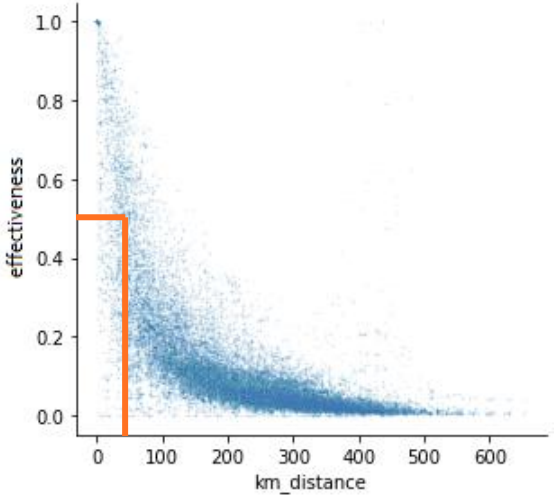
- Locational effectiveness determines what grouping structure sizes are reasonable and, thereby, how many are needed. How precisely does the effectiveness relate to transmission distance?
- How to cluster the transmission system nodes according to (electrical) proximity?

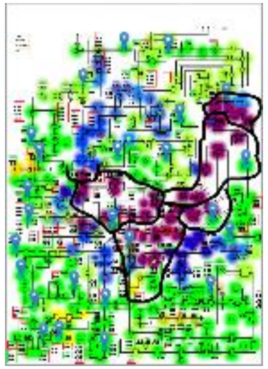
Investigation results

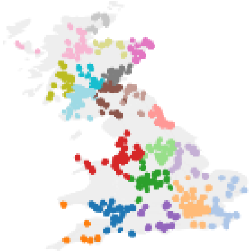
Effectiveness can be estimated to 50% at 50 kilometres transmission distance.

Top-down zoning approach would require 100+ grouping structures.

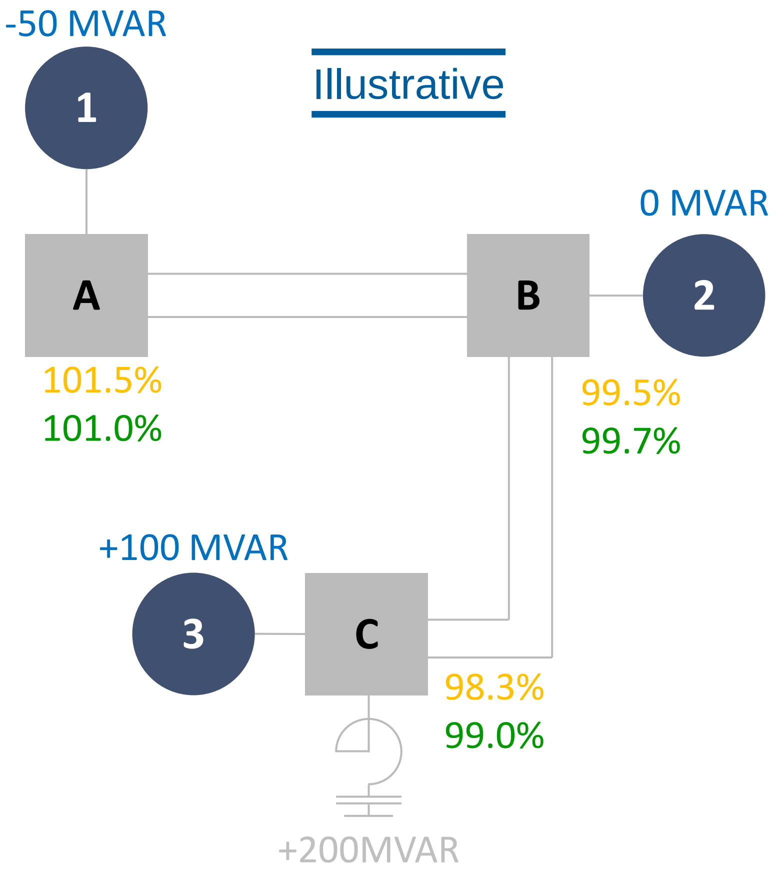
100+ grouping structures would hardly be transparent to providers.
⇒ not recommended
⇒ look into nodal approach instead



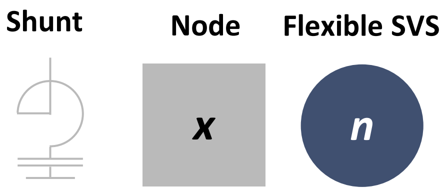




Defining the demand – Nodal approach in a nutshell



- Initially, existing VAR providers are not sufficient to bring voltage within assumed voltage control targets (±1%).
- Adding the flexible SVS brings the voltage within voltage control targets.
- VAR outputs of flexible SVS represent VAR needs.



Voltages in % without flexible SVS
Voltages in % with flexible SVS

Nodal Effectiveness for providers

Effectiveness

Providers do not necessarily need to be connected at the exact same node where the need has been identified – within short distance the effectiveness can still be reasonably high.

Effectiveness is captured in matrix form, giving pairwise effectiveness between nodes. Values are determined through power flow sensitivity analysis.

Challenges:

- The number of nodes (bus bars) in big power systems is large, resulting in big effectiveness matrices.
- Effectiveness is not static, but depends on grid state (scenario) and on the considered contingency case.
- Calculating useful effectiveness factors (the elements in the matrix) is tricky – while they can be derived reasonably easily from power flow sensitivity factors, the sensitivity factors depend on the control modes of the connected generators and other controlling assets.

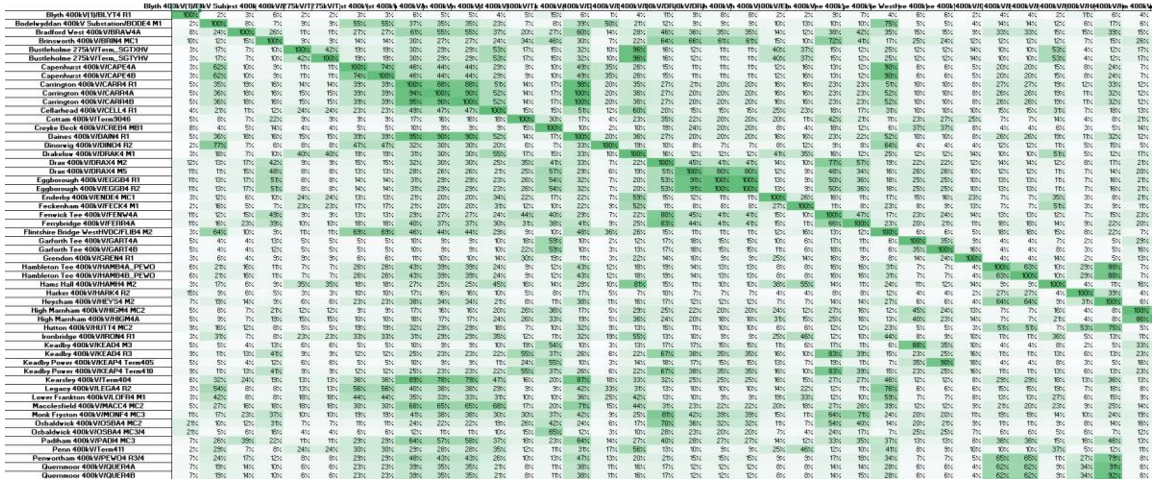
Note: Users must be aware that effectiveness factors are a linear approximation of a non-linear physical relationship and therefore never fully accurate.

Example for illustrative purpose

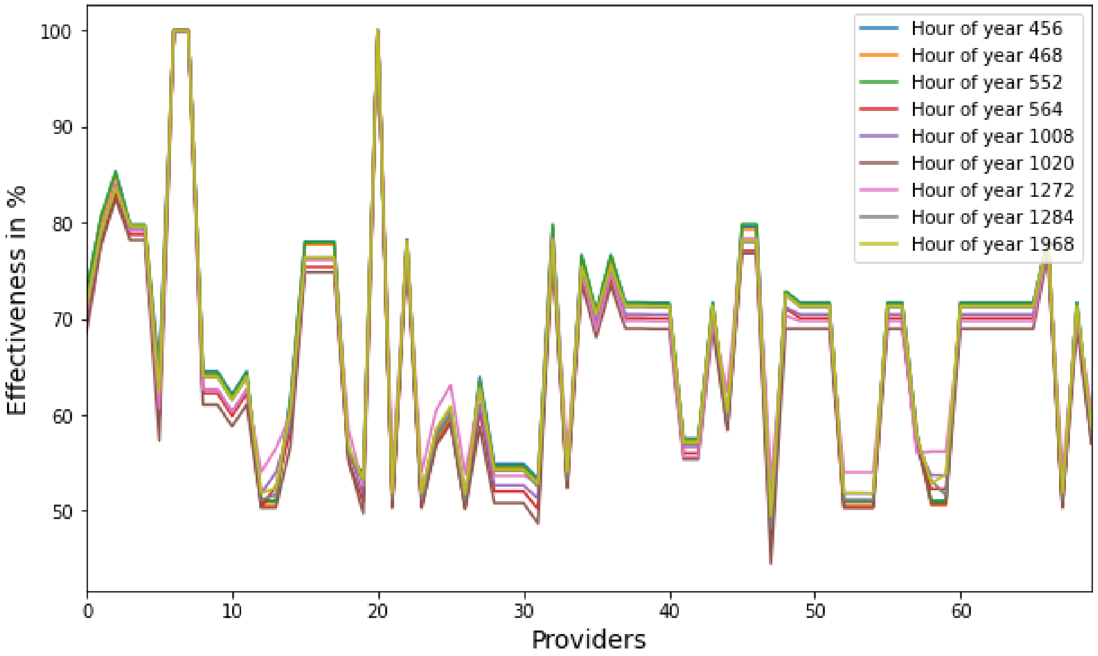
Below is a snapshot example of an effectiveness matrix where demand nodes are listed in the first row and provider nodes in the first column.

We have colour coded the sheet so that effectiveness factors close to 100% are green and effectiveness factors closer to 0% are white.

Ultimately, a matrix will need to be published in a simple and readable fashion to provide good signals to providers about locations able to provide effective solutions to demand nodes.



Effectiveness in different situations



Conclusions on time step variations

If the topology remains identical, the effectiveness of providers towards the selected transmission node remain relatively constant across time steps (i.e., different dispatches).

In the example graph, maximum effectiveness changes are in almost all cases below 3%, and at maximum 9%

This is sufficiently narrow to justify effectiveness factors changing less regularly, however if major topology changes occur then effectiveness factors may need to be redefined

Agenda

Key messages

There is a critical **trade-off** in the market arrangements between **complexity and efficiency;** ultimately arrangements that are too complex may present barriers to deployment for ESO and barriers to entry for providers

Single timeframe market approaches fall short, as they do **not adequately facilitate crucial decisions** that must be taken by providers (investment, operational, closure)

Long-term timeframes mean that ESO is able to ensure **system security** by giving participants a higher degree of certainty in making investment decisions – the assessment of TO counterfactual solutions at this stage ensures **value for consumers.** We are also proposing a year ahead (T-1) to finesse procurement volumes

Including a **short-term** market ensures there is an appropriate route to market for a broad range of potential participants, facilitating providers that may be exposed to volatile opportunity costs, high variable costs, and/or low availability visibility – ultimately increasing competition & resources available and promoting **value for consumers** and contributing to **system security**

Systematic and recurring long-term market obliges ESO to forecast requirements regularly. This acts to ensure a **higher degree of transparency** for market providers who are able to plan and build project pipelines accordingly

Procurement strategy of **opportunistic buying** represents value for consumers while ensuring system security. The shortfall is always bought if it cannot be met in subsequent timeframes **ensuring security**. If provider bids represent perceived value for money, ESO can procure additional capability from eligible providers in advance in the interest of **value for consumers**

'Package' bids within a **combinatorial auction** allow providers to **offer synergies** where they exist. The advantages of a **pay-as-clear** market are significantly **diluted** in the context of a reactive power market – **pay-as-clear** market designs are **difficult** to apply practically and effectively on a nodal basis, as **multiple clearing prices** (for products and nodes) must be determined. Each point may only have a small number of effective bidders and market power is better controlled with **pay-as-bid pricing**

Key recommendations

The preferred market design should build on **existing arrangements** and **learnings** from the Pathfinder process to ensure complexity can be managed

We have recommended a market design that is run over **two timeframes**

- **Long-term** annual markets operating in **investment timeframes** which offer multi-year contracts to underpin investment in assets, complemented by annual **year-ahead** contract rounds to finesse procurement
- **Short-term** market which operates at the **day-ahead** stage to enable participation of assets which are unable to make long-term commitments
- This is complemented by the continued use of the Balancing Mechanism as a back-stop

In both market timeframes, we are proposing an opportunistic procurement strategy

- ESO must buy at least the **shortfall** against the requirement where it exists
- ESO reserves the right to **purchase more** than the minimum quantities required, **if economic** (if prices offered are lower than expected alternative costs at subsequent timeframes)

We recommend **different remuneration** mechanisms in **different timeframes**:

- In the long-term market, we are proposing an **availability payment only**, reflecting the cost structure of appropriate asset types
- In the short-term market, we are proposing a combination of an **availability payment** and a **utilisation payment** at prevailing ORPS rates (for ease of metering settlement, with a potential to move to user defined utilisation in the future)

We are recommending a **pay-as-bid** approach in both timeframes due to the nodal nature of the market, and multiple products being procured simultaneously – pay-as-clear was deemed an impractical approach due to the need to construct multiple clearing prices to accurately reflect value of locational services and pay-as-bid may help to control any local market power

All commercial providers are ultimately eligible to participate (though this is subject to different criteria in long/short term timeframes), though will only be selected if they bring a **benefit to the system** in terms of **incremental capability** ('additionality') and/or **cost efficiency**

Process to develop and select high level market design

1a. Scene setting

1

Establish 'givens' and make **assumptions** on all relevant topics

Assumption		Implication
xxx	▶	yyy
xxx	▶	yyy
xxx	▶	yyy

1a. Scenario definition

2

Identify **key uncertainties** in physical world and define **scenarios (FES)**

Uncertainties

- Need for new technologies
- Need for locational prices

A	B
C	D

1b. Objectives and criteria

3

Establish **design principles** (objectives and priorities)

Primary principles	Cost	Sustainability	...
Sub principles	Stability	Investability	...
Constraints	100% RES	Carbon negative	...

2a. Building blocks and options

4

Define **building blocks**, and the **options** for each building block. This defines the scope of the market design.

Building blocks	**Options**		
Approach to cap. adequacy	Scarcity pricing	Capacity mechanism	...
Approach to regulation	Prescriptive	Open	...
…	...	...	...

2b. Strawmen design options

5

Create '**strawmen**' (high-level designs) that explore alternative **philosophies**; and have the **scenarios** in mind

Building blocks	**Strawman 1**	**Strawman 2**	**Strawman ...**
Approach to cap. adequacy	Scarcity pricing	Capacity mechanism	...
Approach to regulation	Prescriptive	Open	...
…	...	...	...

2b/c. design options assessment

6

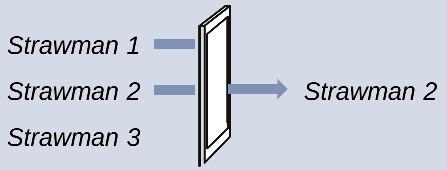
Assess each **strawman** against **design principles** in the context of all **scenarios**

	Cost	Sustainability	...
Strawman 1	○	◕	●
Strawman 2	◕	●	●
Strawman 3	○	○	◕

3b. Final end to end solution

7

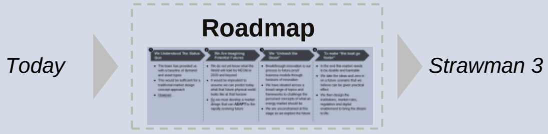
Select the **end-state strawman** that performs best across the **scenarios**



3c. Final recommendation

8

Develop a **roadmap** to transition to **end-state strawman** from today



nationalgridESO AFRY ÅF PÖYRY

MARKET DESIGN

Market objectives create a framework for evaluation of market design performance based on desired outcomes

Primary objectives

Ensuring **cost efficient provision** of reactive power to **maintain system voltage security** in the context of a **zero-carbon system**

Secondary objectives

Practical
- Ease of implementation
- Ease of ongoing operation

Investable
- Respecting existing investments
- Supporting efficient future investments

Transparent
- Visibility of service values
- Clear procurement decisions

Enduring (stable)
- Suitable/adaptable to future challenges
- Well understood governance for changes

Consumer value
- Promoting competition between providers
- Minimising cost burden on customer

Freedom of choice
- Technology agnostic
- Avoiding lock-ins

Constraints

No capability only solutions	Central buyer (NG ESO) vs. decentralised obligations (supplier)	No modification of existing ORPS/obligations

Why do we need objectives?

– The market design process should be focussed on desirable outcomes – what do we want the market to actually do?

– Objectives allow us to make our intentions for the market mechanism clear.

How do we choose objectives?

– Primary objectives outline the overall desired end-state ignoring difficult questions on the physical realities.

– Secondary objectives allow us to set the context, the key questions are:

  – what do we believe the market will need to achieve primary objectives?

  – Is there anything that doesn't define ultimate success, but is important enough to be considered in the process?

What are the implications for preferred solutions?

– Objectives give us a framework to evaluate performance of proposed options, adding structure to an inherently nebulous process.

  – *Evaluating key choices against an established framework allows us to identify and capture areas of uncertainty where they exist.*

– We can move to identify our desired solution, generally a solution that best meets the objectives – however the relative weighting of importance is subjective.

MARKET DESIGN

The primary objectives of the market design set a framework to determine success

Primary objective	Explanation & rationale
Cost efficient provision	– Cost efficiency refers to the overall economic efficiency of the system[1] in this context, reducing the spend required to meet reactive power constraints on the network relative to the baseline. – In recent years costs for managing voltages on the network have increased substantially and is one of the key drivers to exploring reform options today. – Any future arrangements need to establish the framework to deliver a benefit with respect to current voltage management practices.
Maintain voltage security	– The ESO is intending to procure service to comply with licence obligations to ensure a safe and reliable supply of electricity throughout the network. – This is the ultimate purpose of the market, and will be delivered through procuring a suite of reactive power products which will give the ESO the tools needed to manage the system voltage. – Whilst this is the ultimate goal, ignoring other key objectives does not constitute 'success' as solutions delivered may not provide enduring security in an evolving energy landscape.
Zero carbon compatible	– National Grid ESO has committed to be able to run the system with net-zero carbon emissions in any given period should the market deliver that solution (by 2025). – With the evolving system, it would be a fallacy to design market arrangements which cannot accommodate technologies capable of delivering against this commitment. – In the context of reactive power, this means ensuring arrangements are able to cater for scalable zero-carbon solutions for providing reactive power services.

Notes: [1]It does not explicitly address which parties reap the benefits of reduced cost (i.e. the impact on producer and consumer surplus), however in the context of electricity supply it is often implied that reduced costs lead to greater consumer benefits, we have added a secondary objective to make this point explicit.

MARKET DESIGN

Secondary objectives help to enable primary objectives, and address other key themes that don't preclude market success

Secondary objective	Explanation & rationale
Consumer value	– Whilst economic efficiency should be the ultimate goal of a market mechanism the distribution of value that a market is able to realise through increased efficiency is an important consideration. – The solution should promote competition between all providers (and their preferred solutions) to ensure economic potential is realised and ultimately deliver value for money for consumers.
Transparent	– Transparency is needed for a market to function effectively, the absence of sufficient information on which to make commercial decisions could lead to inefficient outcomes. – In the context of a reactive power market with a single buyer, there is a need to communicate needs in a way that allows market participants to understand their costs of service provision to the greatest degree possible. – Without sufficient transparency additional risk is placed on the sellers which will feed through into their bidding behaviour.
Investible	– The market should give investors sufficient clarity for them to recognise and manage their risks. – Risks should be borne by the party most suitably equipped to bear them, undue unknowns should not be placed on providers unless there is sufficient reward to justify these risks. – Incentives should not just target investment as a whole, but focus on rewarding the right investments to improve overall system efficiency .

MARKET DESIGN

Secondary objectives help to enable primary objectives, and address other key themes that don't preclude market success

Secondary objective	Explanation & rationale
Practical	– Any market arrangements must be practical from both a buyer and sellers perspective, sharing of the burden of responsibility for dealing with unknowns (allocation of risk and corresponding rewards). – The solution itself must be deliverable from the ESO perspective, unnecessary complexity can lead to additional administrative cost burdens which can offset some benefits of implementation
Enduring (stable)	– The market design should be sufficiently stable for market participants to avoid unnecessary administrative burden and associated costs. – Give providers confidence in the new market arrangements that participation is meaningful and sufficiently valuable to incentivise ongoing participation (ultimately helping to promote liquidity).
Freedom of choice	– Freedom of choice for providers in terms of the technologies they wish to employ to participate in the market. – Freedom of choice for providers to maker commercial decisions and trade off between different value streams if price signals. – Freedom for the ESO to change arrangements should the market fail to deliver in line with other objectives and needs (e.g. tightening rules to prevent anti-competitive behaviour).

MARKET DESIGN

We defined 10 key building blocks, each with different options – these creates the framework for the market design (strawman) options

Timeframe

Short term vs. long term market

Contract types

Contract alternatives with different delivery obligations

Eligibility

Classifies participants eligible for payment

Pricing mechanism

How services are remunerated

Product Linking

Cover potential linking between products

Frequency of procurement

Defines how frequent the market is run

Locational requirement

Method for defining locational requirements

Provider effectiveness

Defines how effectiveness factors are assessed

Availability requirement

Minimum availability requirement during the contract period

Regulatory back-stop

Principles for how to apply price caps

MARKET DESIGN

We have defined six alternative contract types, targeted at different requirements and provider segments

			Description	Objective	Targeted segment
Long-term	Base	**Firm baseload**	– Provider commits to firm availability with a high expectation of reliability throughout the contract period – Product duration e.g. 10 year baseload	– Meet baseload need that *can* be forecast	– Firm capacity with lowest cost of providing availability
Long-term	Shaped	**Firm fixed shape products**	– Provider commits to firm availability with a high expectation of reliability throughout the contract period – Product duration e.g. seasonal or daily-peak	– Meet shaped (peak) needs that *can* be forecast	– Firm capacity with medium cost of providing availability
Long-term	Shaped	**Conditional products**	– Committed under certain predefined conditions – E.g. when wind is blowing	– Meet needs that correlates with types of variable production	– Firm capacity with material cost of providing availability, which NGESO would prefer not to use baseload
Long-term	Shaped	**NGESO 'call options'**	– Provider commits to availability on demand by NGESO throughout the product duration, at contracted qty and price – Provider paid only when ESO calls for availability	– Meet peak needs that *cannot* be forecast	– Firm capacity with high cost of providing availability, which NGESO would prefer to call only when needed
Long-term	Shaped	**Non-firm provider 'put option'**	– Non-firm contract for availability. Provider has an option to sell its availability [day-ahead] at contracted qty and price – Provider paid only when announcing availability – *Requires a short-term mechanism that guarantees a payment for the volumes which the provider can (and wish to) make available through a non-firm contract*	– Incentivise incremental capability increasing overall capacity for which availability *cannot* be forecast	– Variable RES providers able to evaluate incremental investment
Short-term	Base	**Short term (firm)**	– Firm contracts with short procurement lead time [day-ahead] – Product duration at low granularity [e.g. 30min]	– Meet short term needs, accurately, in any direction	– Firm capacity – Route to market for variable RES providers and/or providers with high variable/opportunity costs

nationalgridESO AFRY ÅF PÖYRY

MARKET DESIGN

4 design options (strawmen) were created based on combinations of long and short timeframes; existing arrangements; different contract types; and other combinations of the building blocks

A	B	C	D
Long term (LT) only	**Short term (ST) only**	**ST + LT**	**ST + LT 'complex'**
Multiple new LT market arrangements, replacing the Pathfinder (PF) arrangements.	New ST market. No *new* Pathfinders or other long term arrangements.	New ST market alongside LT baseload market run ad-hoc (similar to PF)	New ST market alongside multiple new LT contracts, run at scheduled intervals

Note: Adjustment to ORPS arrangements are not within the scope of this project, however their interaction with potential products has been considered

Objectives | Building blocks | **Strawman options** | Assessment | Refinement

MARKET DESIGN

The combinations of timeframe and contract types were selected to facilitate the broadest range of providers possible

Timeframe	Product	A – Long term only (LT)	B – Short term only (ST)	C – ST + LT	D – ST + LT 'complex'
Long-term (timeframe)	**Existing PF** 1,2,3	✓	✓	✓	✓
Long-term (timeframe)	**Future advanced PF (ad hoc)** Firm Baseload	✗	✗	✓	✗
Long-term (timeframe)	**Firm baseload**	✓	✗	✗	✓
Long-term (timeframe)	**Firm shape products** (Fixed shape products, conditional & 'Call options')	✓	✗	✗	✓
Long-term (timeframe)	**Non-firm provider 'Put options'**	✓	✗	✗	✗
Short-term (timeframe)	**ST day-ahead market**	✗	✓	✓	✓
Short-term (timeframe)	**ST market requirement**	✗	Gross* (net of existing PF contracts)	Shortfall	Shortfall
Short-term (timeframe)	**BM and other ad hoc balancing services**	(✓)	(✓)	(✓)	(✓)

MARKET DESIGN

The options have different conditions which providers need to meet be eligible for participation

Eligibility	A: Long term only (LT)	B: Short term only (ST)	C: LT + ST – LT	C: LT + ST – ST	D: LT 'complex' + ST – LT	D: LT 'complex' + ST – ST
Incremental	✓	✗	✓	✗	✗	✗
Global selective	✗	✗	✗	✓	✓	✓
Global	✗	✓	✗	✗	✗	✗

	Incremental	Global selective	Global (Gross)
Eligible	– New assets/providers (beyond ORPS) – Existing providers with new capability (beyond ORPS)	– In general, all providers are eligible. However, NGESO discretion for awarding contracts – ESO buys (expected) shortfall plus the economically desirable – incl. ORPS if it is cheaper than alternatives[1]	– In general, all providers are eligible. Limited NGESO discretion for awarding contracts – This means it also includes ORPS providers within ORPS ranges ; ORPS providers outside of ORPS ranges; non-ORPS/uncontracted providers
Excluded	– Existing TO assets and LT contract holders – New and existing ORPS providers within ORPS ranges	– Existing TO assets and LT contract holders – Uneconomic ORPS providers more expensive than BM alternatives or ORPS utilisation price	– Existing TO assets and LT contract holders

nationalgridESO AFRY ÅF PÖYRY

MARKET DESIGN

The strawmen have been evaluated against each of the objectives, highlighting strengths and shortfalls - leading to a desired option

BASIS FOR ASSESSMENT

Objectives – Form the criteria by which a strawmen were assessed

Stakeholder engagement – Inputs from surveys, 1-2-1 sessions and industry workshop fed directly into the design and assessment process, helping to understand the market perspective

ESO experts – Internal dialogues with ESO experts, testing assumptions and the different options against system operational requirements

Fundamentals – Fundamental economic principles and experience from similar and relevant market arrangements

OUTCOME

Desirability – The outcome give indications for which of the strawmen is expected to give most desirable outcomes, based on their high level design principles

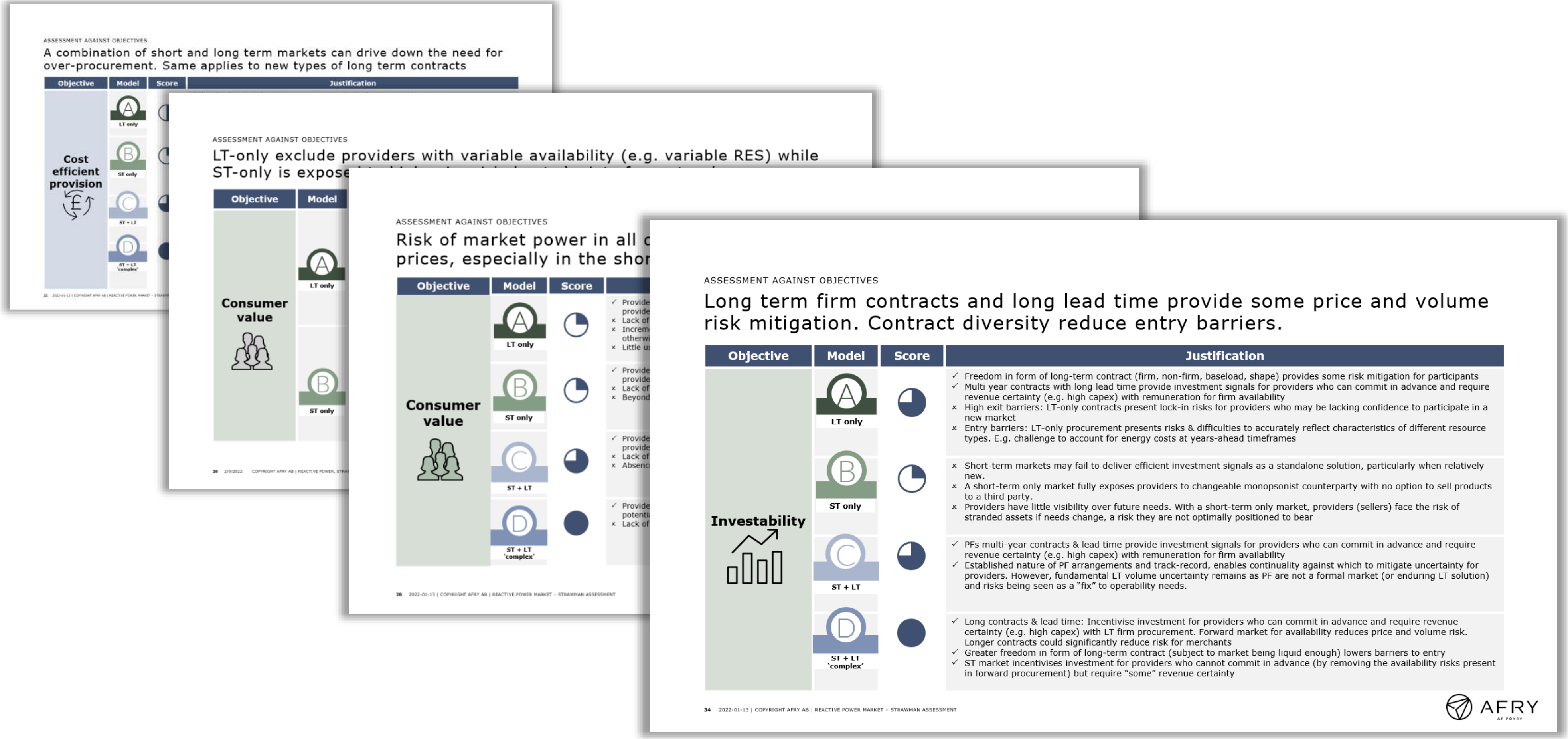
Capture input – Evaluating multiple choices against an established framework allows us to test ideas with stakeholders and to identify and capture areas of uncertainty where they exist

Narrowing the design – Moving from four design options to one helps to eliminate none-viable options and to focus on the more material details of final recommended market design

Further work – The appraisal form a basis for the recommended market design, and should work as a guidance rather than limiting further work in the final implementation of the market

MARKET DESIGN

A thorough appraisal of the merits and drawbacks of each strawman model has been undertaken

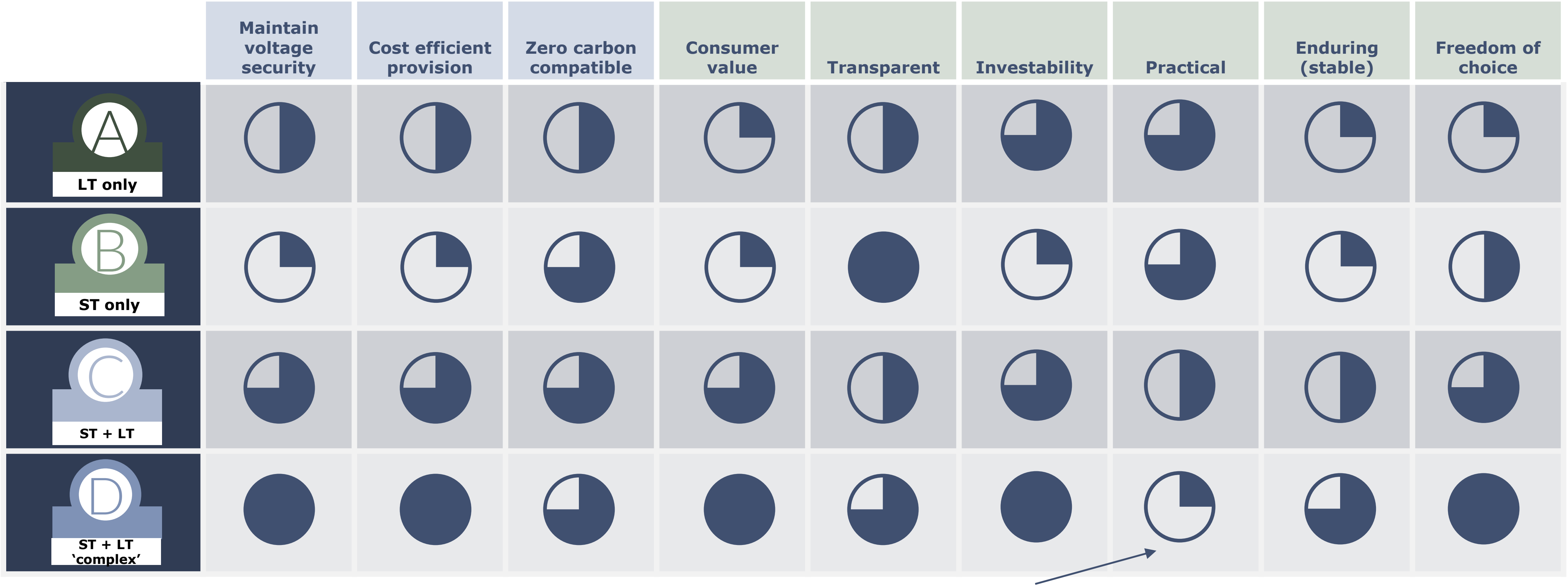

ASSESSMENT AGAINST OBJECTIVES

Long term firm contracts and long lead time provide some price and volume risk mitigation. Contract diversity reduce entry barriers.

Objective	Model	Score	Justification
Investability	A LT only		✓ Freedom in form of long-term contract (firm, non-firm, baseload, shape) provides some risk mitigation for participants ✓ Multi year contracts with long lead time provide investment signals for providers who can commit in advance and require revenue certainty (e.g. high capex) with remuneration for firm availability × High exit barriers: LT-only contracts present lock-in risks for providers who may be lacking confidence to participate in a new market × Entry barriers: LT-only procurement presents risks & difficulties to accurately reflect characteristics of different resource types. E.g. challenge to account for energy costs at years-ahead timeframes
	B ST only		× Short-term markets may fail to deliver efficient investment signals as a standalone solution, particularly when relatively new. × A short-term only market fully exposes providers to changeable monopsonist counterparty with no option to sell products to a third party. × Providers have little visibility over future needs. With a short-term only market, providers (sellers) face the risk of stranded assets if needs change, a risk they are not optimally positioned to bear
	C ST + LT		✓ PFs multi-year contracts & lead time provide investment signals for providers who can commit in advance and require revenue certainty (e.g. high capex) with remuneration for firm availability ✓ Established nature of PF arrangements and track-record, enables continuality against which to mitigate uncertainty for providers. However, fundamental LT volume uncertainty remains as PF are not a formal market (or enduring LT solution) and risks being seen as a "fix" to operability needs.
	D ST + LT 'complex'		✓ Long contracts & lead time: Incentivise investment for providers who can commit in advance and require revenue certainty (e.g. high capex) with LT firm procurement. Forward market for availability reduces price and volume risk. Longer contracts could significantly reduce risk for merchants ✓ Greater freedom in form of long-term contract (subject to market being liquid enough) lowers barriers to entry ✓ ST market incentivises investment for providers who cannot commit in advance (by removing the availability risks present in forward procurement) but require "some" revenue certainty

34 2022-01-13 | COPYRIGHT AFRY AB | REACTIVE POWER MARKET – STRAWMAN ASSESSMENT

Overall strawman D scored highest through qualitative appraisal. Reducing some of the complexity (adopting elements of C) will make it more practical



Option D scores the highest but lacks practicality for both ESO and providers – conclusion is to go with a simplified version of D/more complex version of C

MARKET DESIGN

The assessment concluded that a hybrid of C and D is the most pragmatic way forward whilst maximising benefits against the objectives

A – LT only

Not preferred option because of unpredictability of demand.
- × Leads to over-procurement to maintain adequate system security, raising cost
- × All risks needs to be mitigated by NGESO in the long term when degree of predictability is low
- × High barriers of entry for some technologies

B – ST only

Not a viable option (initially) because:
- × Exposing ESO to system security risk (operates beyond investment timeframes)
- × Limited incentives for new investment – exposes providers to changeable needs with single buyer risk

C – ST + LT

- ✓ Combination of long term and short term market gives the best balance between system security and cost efficiency, while increasing consumer value by promoting competition from a wider range of technologies
- × Ad-hoc nature of information sharing and procurement difficult for providers to build pipelines and offer most effective solutions

D – ST + LT 'complex'

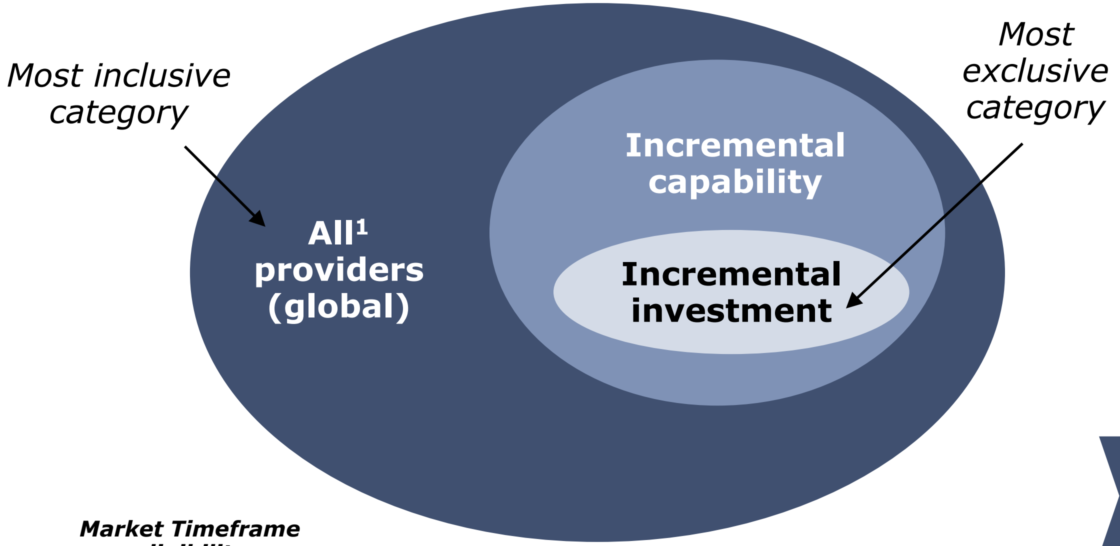
- ✓ Adding peak contracts allows reducing over-procurement compared to baseload only, thus can save cost while also increasing freedom of choice.
- × Introducing overly-complex contracts makes market less practical and value less transparent

E – ST + LT

Long Term market with simple product(s) + Short Term day-ahead market ✓

MARKET DESIGN

Due to the nature of arrangements (pay-as-bid, locational, overlapping obligations) we propose 3 categories of eligibility for our preferred option



Market Timeframe eligibility

Long term T-4	Incremental *investment* only (similar to CM, investment threshold test)
Year ahead T-1	Incremental *capability*, including ORPS providers outside of MSA ranges, existing providers with no MSA in place, closing assets
Short term	All[1] providers including ORPS providers in Mandatory Service Agreement (MSA) ranges

Justification of eligibility exclusions

Long term T-4	– This process is for long term contracts, supporting *incremental investment* in new assets – Opportunistic procurement is possible, if a new investment would be cheaper than the alternative – Inclusion of existing assets would complicate the process and cloud transparency
Year ahead T-1	– This process is closer to delivery than the T-4 round, and NGESO's views of capabilities and needs will be more refined – This is an opportunity for providers with firm availability to monetise *incremental capability* from existing assets, including capability not available under the grid code and also assets which would otherwise be expected to close.
Short term	– This is a final procurement round after the D-1 energy market and interconnector nominations, which allows otherwise uncontracted providers to offer availability to NGESO. – Bids will be accepted if they are needed to meet any remaining shortfall and if they are cheaper than the alternative (including the possibility of activation in the BM).

Notes: [1]All categories exclude providers that already have long term *firm* commitments/contracts to prevent double payment (e.g. Pathfinder contract holders, TO assets in RAB)

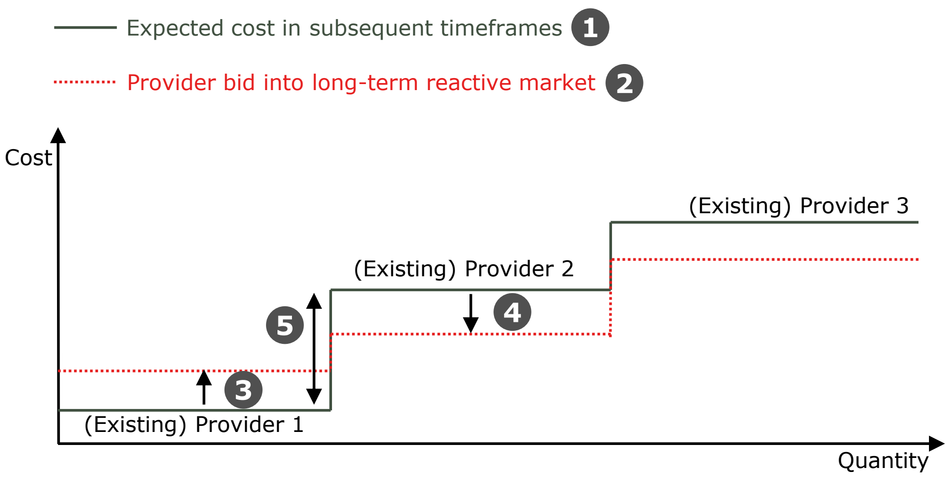
Preferred option

E

MARKET DESIGN

Including existing providers in LT (T-4) would lead to unacceptable balance of risk for consumers, and process would be non-transparent for providers

Stylised example – if global eligibility were permitted in long term market (with opportunistic buying for pay-as-bid market)



1. Cost of procuring in subsequent timeframes must be established **for each provider** over 15 year period
2. Provider bids into long term market with guaranteed availability price (forgoes ORPS payments)
3. Provider 1 offers less competitive price than expected – consequently reject bid
4. Provider 2 offers more competitive price than expected costs – consequently accept bid
5. Relativity of providers bids irrelevant, willingness to pay based on **individual unit long-term forecasts**

Conclusion: Long term (15y) cost (& dispatch) forecast uncertainty too high on an *individual unit level*, balance of risk unacceptable for consumers and process would be non-transparent for providers – include existing asset closer to real time (T-1 for incremental, ST market for all)

nationalgridESO AFRY ÅF PÖYRY

Objectives | Building blocks | Strawman options | Assessment | **Refinement**

Preferred option E

MARKET DESIGN

Our proposed solution has selective eligibility across timeframes due to issues with forecast error, transparency, and practicality

Eligible | Ineligible

	Long term (T-4)	Long term (T-1)	Short term (day-ahead)
Incremental investment	Can be easily identified as providing additionality to ensure security. Buy curve can be established for opportunistic approach based on marginal unit cost displacement (Eligible)	Assets that can deploy quickly should not be excluded from the arrangement (Eligible)	Unlikely to pursue this approach, but providers should be allowed to access short-term market if they don't wish to make long term commitments (Eligible)
Incremental capability	Unclear how to define closing plants with a high level of accuracy, opportunities for other incremental providers in later timeframes (Ineligible)	Offers an opportunity for closing providers, or providers who may not be available in subsequent timeframes. Buy curve can be established for opportunistic approach based on marginal unit cost displacement (Eligible)	Providers with a high opportunity cost, variable cost, or low availability certainty for access to additional capability given a route to market when MW positions and costs are more certain (Eligible)
All	Appetite to pay on individual unit basis in pay-as-bid, multi-timeframe market. Impossible to establish universal buy curve for existing providers. High level of forecast uncertainty for units available in subsequent timeframes (Ineligible)	Appetite to pay on individual unit basis in pay-as-bid, multi-timeframe market. Impossible to establish universal buy curve for existing providers. High level of forecast uncertainty for units available in subsequent timeframes (Ineligible)	Higher degree of certainty on individual unit level costs, precedent exists for procuring existing providers if discount to real time solution in the interest of consumers (Eligible)

AFRY ÅF PÖYRY

Objectives → Building blocks → Strawman options → Assessment → **Refinement**

Preferred option E

RECOMMENDED MARKET DESIGN

	Long-term market	Year-ahead	Short-term market	Description / rationale
Products	– Pre-fault injection – Pre-fault absorption – Post-fault injection – Post-fault absorption			4 products in both markets : – Pre and post fault – Absorption and injection
Product linking	Option to submit mutually exclusive bids or bundled bids for a combination of products[1]			Participants can link products and make their offers mutually exclusive. Applicable for technologies capable of providing both injection and absorption, pre and post fault.
Contract type	Baseload availability [+ Potential for Fixed shape/peak window products][1]	Same as Long-term market	4 hour EFA blocks	Fixed shape/peak considered in the future. ESO preference for short-term market is EFA blocks initially, in line with initial provider feedback.
Locational Requirement	Nodal			Requirements are calculated and communicated per node.
Procurement strategy	Shortfall + Opportunistic			ESO buys (expected) shortfall plus additional capability if economically efficient
Provider Eligibility	Incremental *investment* only (additionality criteria, e.g. new build assets, existing assets making material investments to unlock additional MVAr)[1]	Incremental *capability* only[1]	Global selective: All providers are eligible. However, NGESO discretion for awarding contracts	**Incremental investment:** Capability which doesn't already exist and requires material investment to be accessible **Incremental capability:** e.g. ORPS providers outside of MSA ranges, existing non-ORPS providers, closing assets **Global selective:** NGESO procure if economically efficient to do so. All providers are eligible incl. existing ORPS providers in MSA ranges

*Further investigation is merited

RECOMMENDED MARKET DESIGN

Preferred option E

	Long-term market	Year-ahead	Short-term market	Description / rationale
Frequency of procurement	National annual procurement	National annual procurement	National daily procurement for next day (D-1)	Annual basis for long term, buying the shortfall and/or opportunistic buying (if no shortfall, opportunistic buying can still occur). ST market has the same logic but broader eligibility.
Lead Time	T-4[1]	T-1[1]	D-1 (post-exchange)	Sufficient lead time for asset deployment, closure decisions, and operational decisions across the three time frames.
Product duration	15 year[1]	1 year	4 hour EFA blocks	Aligns with other long-term contracts (CM, CfD) for the long-term market. EFA blocks sufficient granularity based on ESO experience & in line with provider feedback
Payment structure	**Availability** £/MVAr/SP availability payment	**Availability** £/MVAr/SP availability payment	**Availability + utilisation** – £/MVAr/SP availability payment – £/MVAr/SP utilisation via ORPS payment mechanism	**Long term** market mainly targeting high-capex & low variable cost. **Short term** market targeting high availability & variable cost or low availability & variable cost providers.
Clearing principles	Pay-as-bid			Due to nodal nature of requirement and bundled products (multi-clearing price impractical)
Price control	– TO owned asset solution depreciated over [15y] horizon for new build.[1] – Forecasted short term cost for opportunistic procurement	Forecasted cost of meeting need in subsequent timeframes for opportunistic procurement, [price cap TBC][2]	Real-time alternative cost forecast (cost of meeting demand in balancing timeframes)	One tool to mitigate potential manifestation of market power given nature of reactive needs

[1]Further investigation is merited
[2]Existing procurement routes remain open to ESO to solve specific challenges outside of reactive specific market arrangements if necessary

RECOMMENDED MARKET DESIGN

Preferred option E

	Long-term market	Year-ahead	Short-term market	Description / rationale
Availability requirement	High [95%][1]	High [95%][1]	100%	Failing to deliver agreed availability/ utilisation results in facing non-performance process
Non-performance process	Penalties: Non-payment, becoming more 'penal' below availability requirement (similar to current pathfinder approach)		Firm 'penalty' for non-delivery of declared availability (beyond non-payment [strong fixed penalty agreed price * X or agreed price + X])[1]	Strong incentives to 'show up' due to criticality of need. Simple to start with. Desirable end state may be to expose participants to replacement costs (akin to imbalance), depending on time frame.
Effectiveness factor	– Effectiveness factor defined individually per node for each demand node – Fixed at point of contracting for the whole contract duration		– Effectiveness factor defined individually per node – Dynamic, i.e. changing over time to reflect changes towards reference node	Effectiveness determined for both pre- and post-fault products. Effectiveness factors subject to change with changing network topology. Effectiveness factor in any market timeframe is the blended effectiveness factor over the periods in relevant contract duration.

[1]Further investigation is merited

MARKET DESIGN

Within the market timeframes we have proposed two different contracts (initially) with the potential to add a third in future

		Availability	Description	Objective	Targeted segments
Long-term	**Year baseload**	24/7, 365 days of the year	– Provider commits to firm availability with a high expectation of reliability throughout the contract period – Product duration e.g. 15 year baseload	– Ensure voltage security, and manage long-term costs	– Firm capacity with lowest cost of firm availability and reactive power utilisation
Long-term	***Fixed shape****	*24/7, all days of the contract period*	*– Provider commits to firm availability with a high expectation of reliability throughout the contract period* *– Product duration e.g. seasonal peaks*	*– Avoid overprocurement from baseload contracts targeting specific seasonal needs (e.g. high summer absorption requirements)*	*– Firm capacity with low to medium cost of providing availability*
Short term	**4H EFA block**	4 consecutive hours	– Firm contracts with short procurement lead time (day-ahead) – 4-hour EFA blocks allows NGESO to shape their demand, without the complexity of the 30min contracts – An EFA day runs from 23:00– 23:00 UK time, procurement for all EFA blocks to happen in the same procurement round	– Top-up from long term contracting, managing costs closer to real time	– Firm capacity – Route to market for variable RES providers and/or providers with high variable/opportunity costs

*** Fixed shape (peak contracts**) are recommended as an option to be considered in the future; however to minimise complexity, implementation of fixed shape contracts may not be desirable in v1.0 of the market.

Preferred option E

MARKET DESIGN

The proposed market process consists of 6 main stages for both long- and short-term market, each run for GB as a whole

1. NGESO forecast MVAr requirements for the contract period
2. NGESO determine what, how and when to procure, 'outside options[1]' are established by the TO
3. Demand and effectiveness factors for all nodes are published
4. Eligible participants bid their availability into one auction
5. Algorithm calculates results subject to procurement strategy, demand curve, and constraints
6. Publishing of results

Notes: [1]See definitions slides

Agenda

Key messages

ESO must manage both compliance risks with their obligations to **ensure system security**, and risks associated with excess **cost of service** procurement on behalf of consumers

The **procurement strategy** reflects these key risks which also form two of our primary objectives:

- the strategy ensures the **shortfall** is always bought (i.e. buys capability if it is needed, and not available in subsequent timeframes e.g. new investment); and
- opportunistically targets solutions which are expected to be **cheaper** than procurement in subsequent timeframes

Long-term T-4 timeframes target **incremental investment** or, in the case of T-1, target incremental capability & influence closure decisions

The short-term market targets all providers, either to **ensure system security**, or to ensure **value for consumers**

At all timeframes, **forecasts** will need to be established to define expected **future requirements** to ensure voltage security/shortfall procurement (methodology provided by technical workstream), and define expected **future costs** for use in opportunistic buying – this multipurpose procurement will take place as part of a single process

Long-term markets | Short-term market

PROCUREMENT APPROACH

Two of ESO's primary objectives across timeframes are to ensure voltage security and efficient costs

Risk faced by ESO

- Risks to the ESO manifest as a function of licence obligations (compliance risk) and balancing cost incentives (financial risk). Both of these risks can also be deemed as reputational risks.
- Obligations to keep voltages within defined (SQSS) limits are imposed on the ESO through licence obligations, however ESO cannot own and operate voltage compensation equipment throughout the network.
- In the context of ESO's remuneration framework under RIIO, performance on system operation costs can have a direct financial impact on ESO's business.

Manging risk

Managing voltage security risk

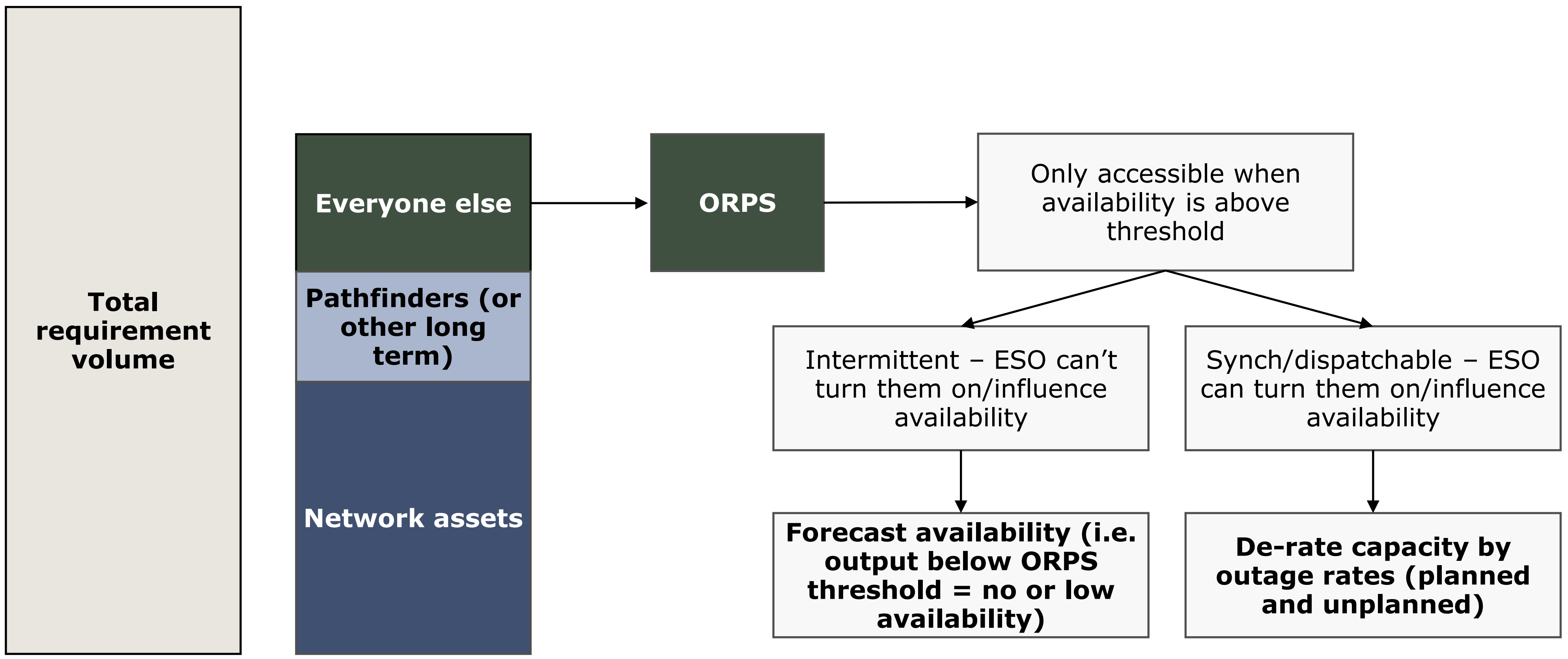
- As ESO is unable to own and operate it's own assets, services must be procured from third parties.
- Securing the system voltages means ensuring sufficient reactive power capacity will be available when needed.
- Due to lead times on new assets, there is a need to procure ahead of time where a gap between capacity and requirement exists.

Managing voltage cost risk

- As ESO is obliged to contract with third parties to secure services, it does not have direct control over costs.
- An indirect approach must therefore be taken through the introduction of efficient procurement mechanisms.
- Procurement mechanism and contracting processes design is critical to ensuring efficient outcomes.

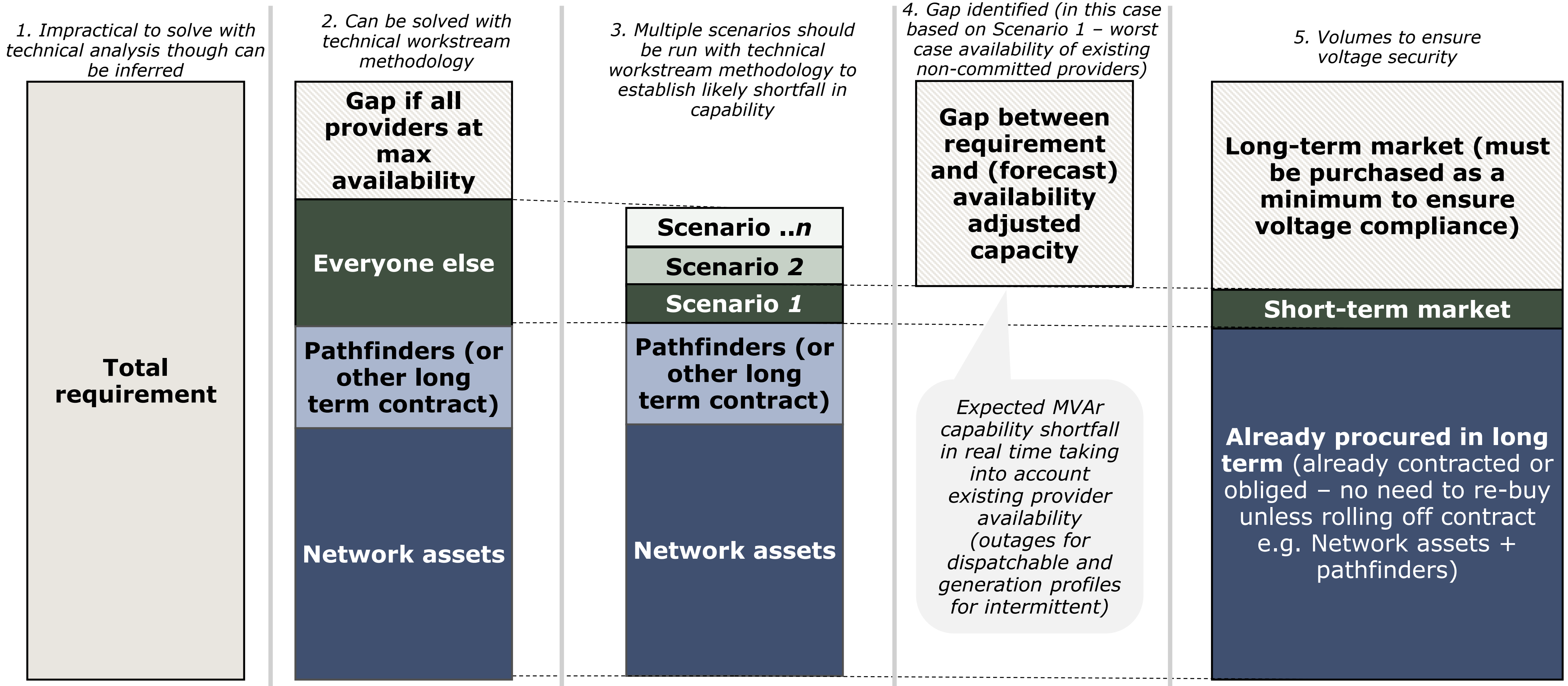
PROCUREMENT APPROACH

The long term market must ensure there is sufficient (available) capacity as operational timeframes approach



PROCUREMENT APPROACH

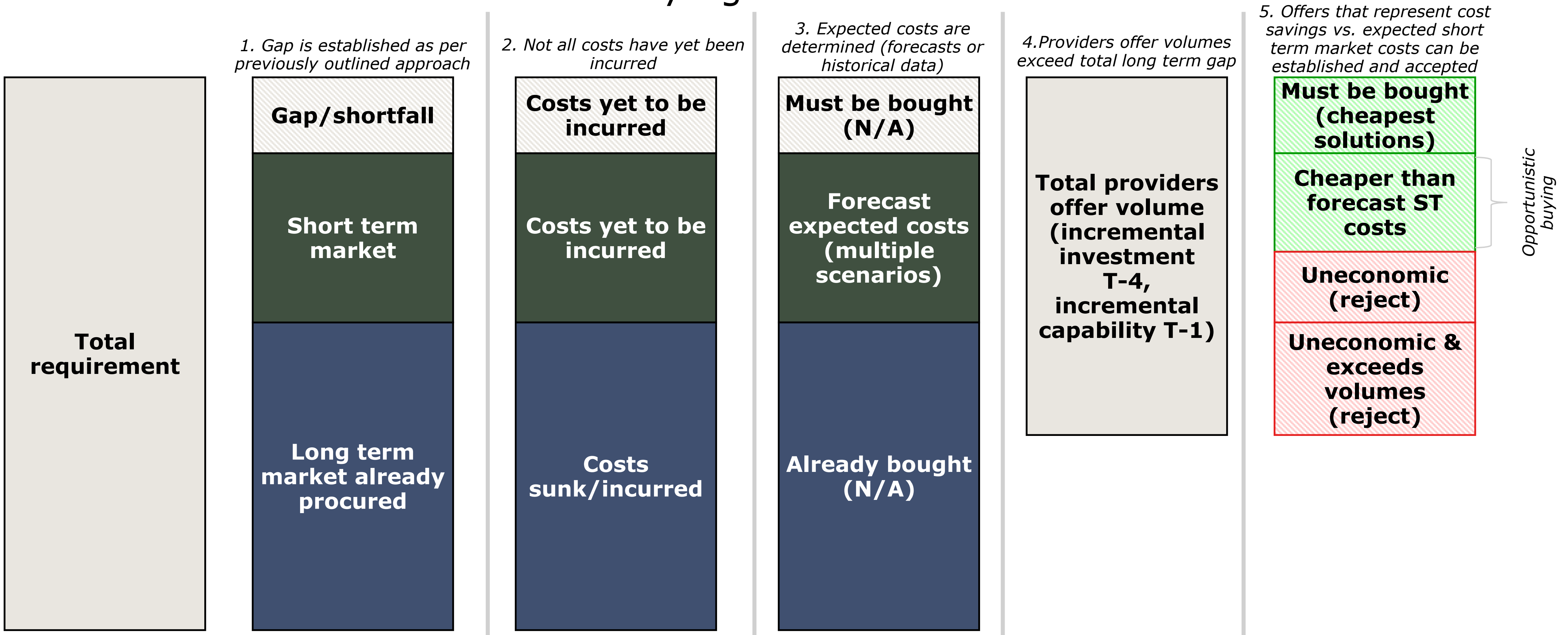
Multiple scenarios can be run to understand the worst case plausible availability and secure sufficient providers to ensure SQSS compliance



Notes: simplified example, in reality a buy curve should be established or least worst regret scenario methodology selection should be employed to determine exact volume that should be procured based on economic trade-offs

PROCUREMENT APPROACH

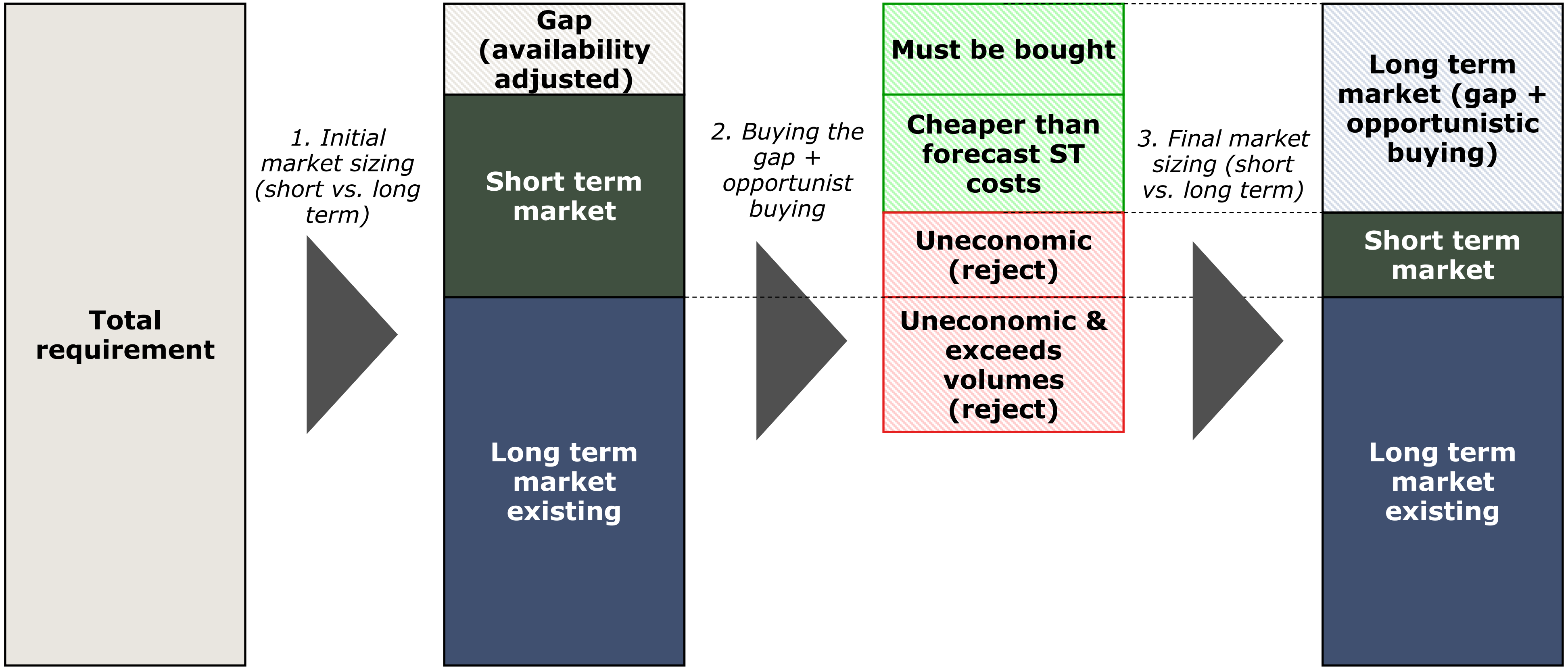
Opportunistic buying – Once the shortfall/gap has been met, ESO may wish to procure additional volumes in the long-term market if it expects a discount relative to short-term buying



Notes: Segments resized from previous slide for readability

PROCUREMENT APPROACH

Opportunistic buying – Once the shortfall has been met, ESO may wish to procure additional volumes in the long-term market if it expects a discount relative to short-term buying



ESO may want to procure different provider types for different reasons

Non-incremental

ORPS providers within MSA ranges (accessible in the BM, can be instructed for MVAr[1])

- Both synchronous and non-synchronous generators have an obligation to provide ORPS, critically this only above a certain MW dispatch threshold (20% for non-synch, SEL for synch).
- Actions can be taken by dispatchable generation to influence their availability (e.g. for synchronous CCGTs can turn on, for non-synchronous batteries can alter output)
- It may be desirable to pay providers for availability **where payments will influence their behaviour.** Critically it is unlikely to be beneficial to pay providers who have no control to increase their active MVAr output such as intermittent providers in this category[1].

Incremental

ORPS providers outside of MSA ranges (not accessible in the BM, no route to instruct MVAr)

- Some providers have oversized converters (or other reactive comp. equipment) able to export additional reactive power beyond what is required in the grid code. Notably from the Market Analysis workstream under this project, grid code requirements are more strict under ENTSO-E (wider MVAr range required for non-synch providers), additional capability may therefore be more broadly accessible (as some providers have indicated under the Market Analysis workstream).
- For some providers (in particular battery storage), there may be a MVAr trade-off meaning there could be a large range of volatile costs for these provider types that varies depending on the opportunity cost of injecting and withdrawing active power from the grid.

Incremental

Other providers

(not accessible in the BM, no route to instruct MVAr)

- The Market Analysis workstream has identified ~10GVAr of potential additional resource out in the system that is as yet uncontracted via ORPS.
- Much of this capacity is embedded generation, a route to facilitate these is being explored separately – regardless any market solution should seek to procure these additional volumes if economic to do so.

Notes:[1]Does raise the possibility for gaming by market participants declaring lower than expected PNs and securing contracts in the category of ORPS providers outside ORPS ranges (where PN is <20% rated MVAr) – this can be managed through efficient monitoring and settlement practices.

Long-term markets | Short-term market

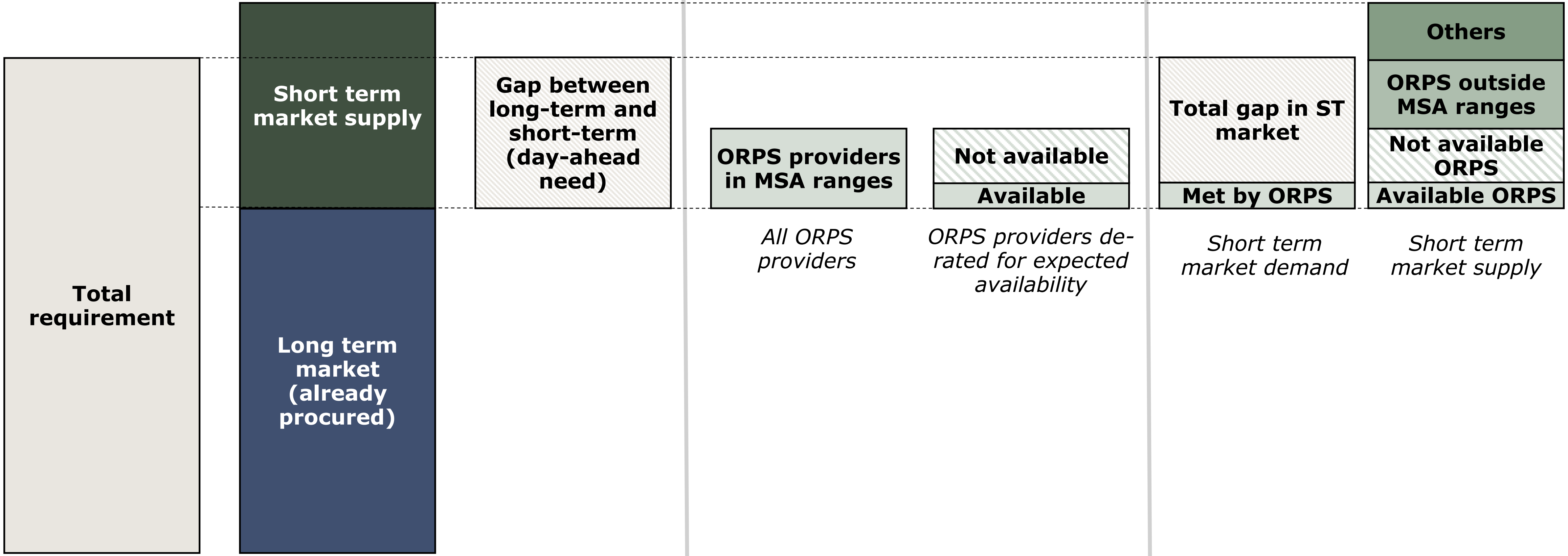
PROCUREMENT APPROACH

The gap (if any) between long-term contracts and short-term needs must be identified

1. The gap between long-term contracts and residual short-term need is established based on day-ahead forecasts of voltage issues, employing the same methodology as the long term, but focussed on a single day

2. Once total need is established, determine expected available capability[1] from ORPS

3. Establish categories for buying, there will be an expected volume of capability from ORPS, ORPS providers that are not available, and potentially a gap between these providers and the total requirement

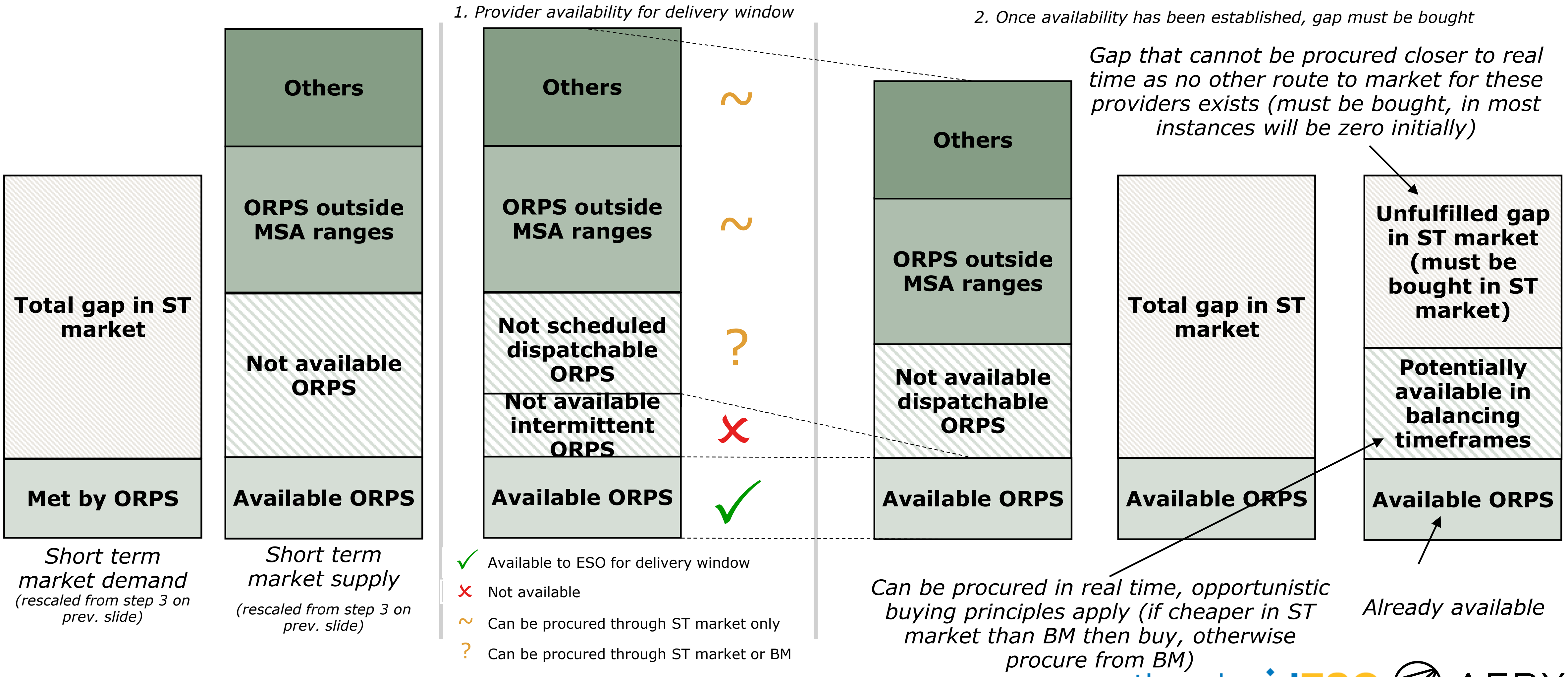


[1]At point of assessment this can be based on PNs, note that if this is a hard-rule it may open opportunities for gaming as plants declare PN=0 when they actually intend to run to be considered for procurement at this stage. One alternative is to procure everyone who can influence their dispatch/availability.

Long-term markets | Short-term market

PROCUREMENT APPROACH

Deciding what to buy opportunistically at the day-ahead stage requires understanding of what is potentially available ‘on-the-day’

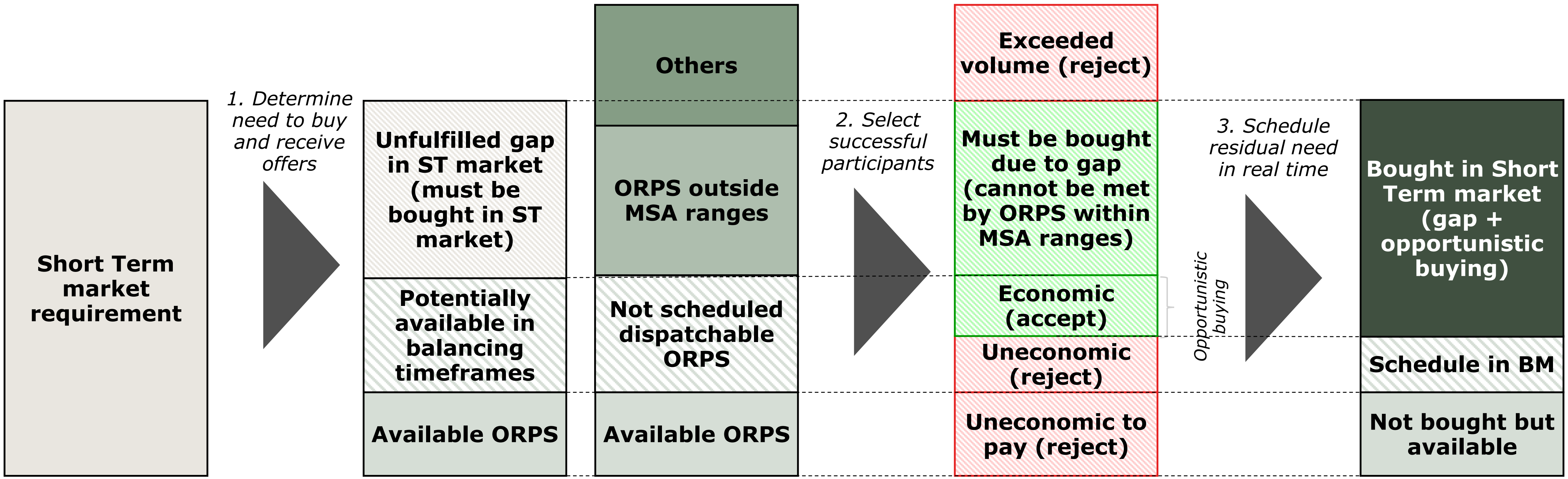


nationalgridESO AFRY ÅF PÖYRY

Long-term markets | Short-term market

PROCUREMENT APPROACH

Ultimately, once real-time is reached all residual needs must be fulfilled either through the short term market or in the balancing mechanism



Long-term markets | Short-term market

PROCUREMENT APPROACH

ESO will have to determine willingness to pay at each stage for opportunistic buying

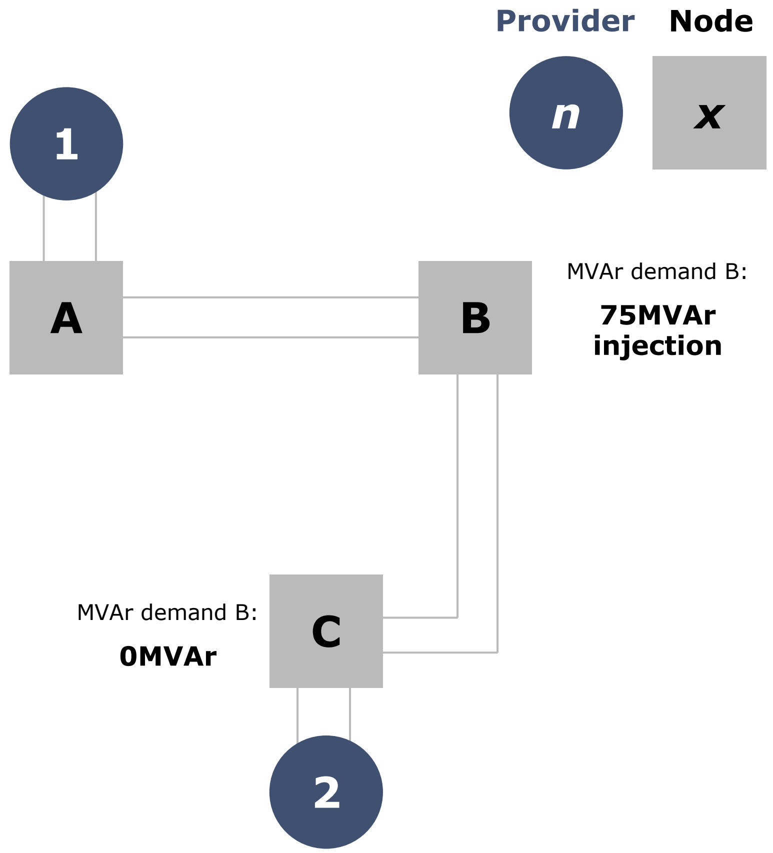
Timeframe	Long term opportunistic buying	Short term opportunistic buying
Type of forecast	Long term forecast of expected costs throughout contract period duration from the short term market (assuming there is no gap)	Forecast short term costs of procuring from the balancing mechanism for the following day
Price forecast approach	Long term fundamental analysis (scenario modelling) – suggested adaptation to FES scenarios to incorporate evaluation as BAU activities (similar to NOA)	Prevailing available bid/offer data from BM and expected action volumes + other costs (i.e. ORPS rates, volumes, replacement costs[1] etc.)
Forecast accuracy and application	Forecast for longer term periods will inherently be less accurate, probabilistic approach or least worst regret decision making principles should apply	Forecast accuracy higher – buy if expected short term market costs are below alternative (balancing mechanism costs) and/or a capability gap[2] remains

Notes: [1]By replacement costs we refer to that fact that if an offer is accepted to access a reactive power provider, a corresponding bid must also accepted to ensure the system remains balanced [2]See definitions slide

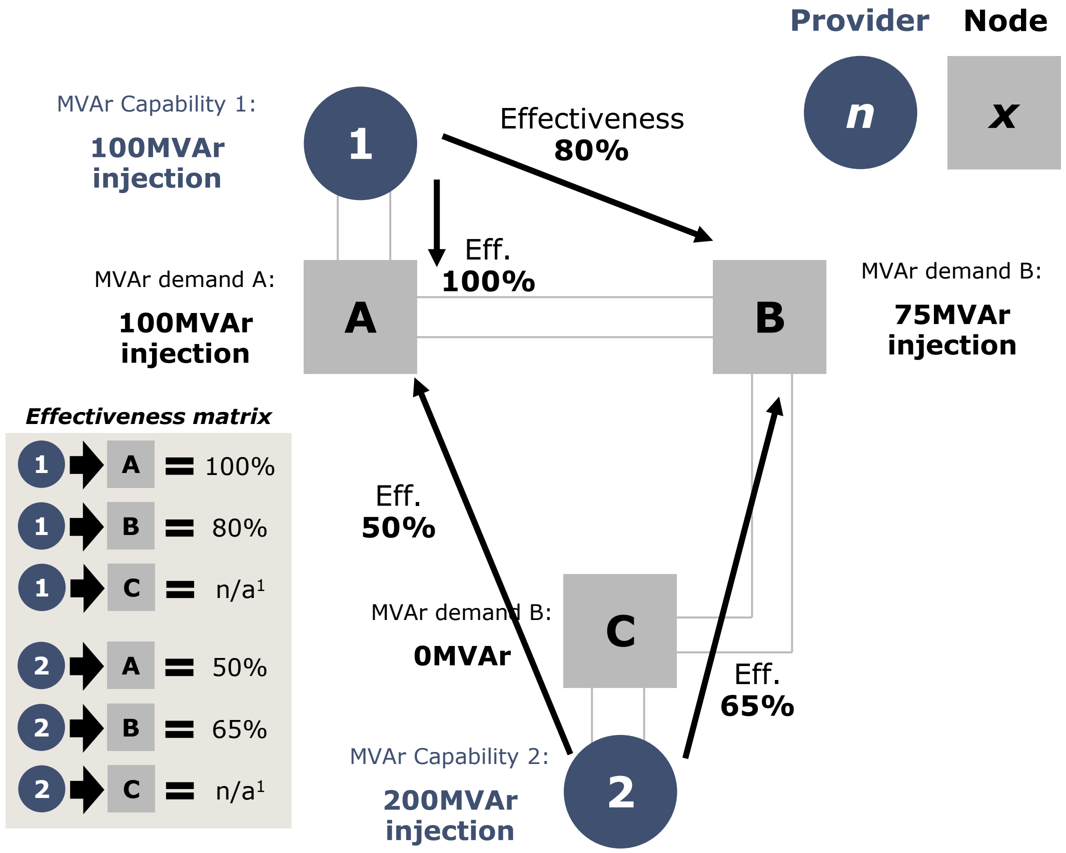
The first stage to assess bids is to establish the supply and demand for reactive power services across the nodes

1. Establish the need

Illustrative simplified example



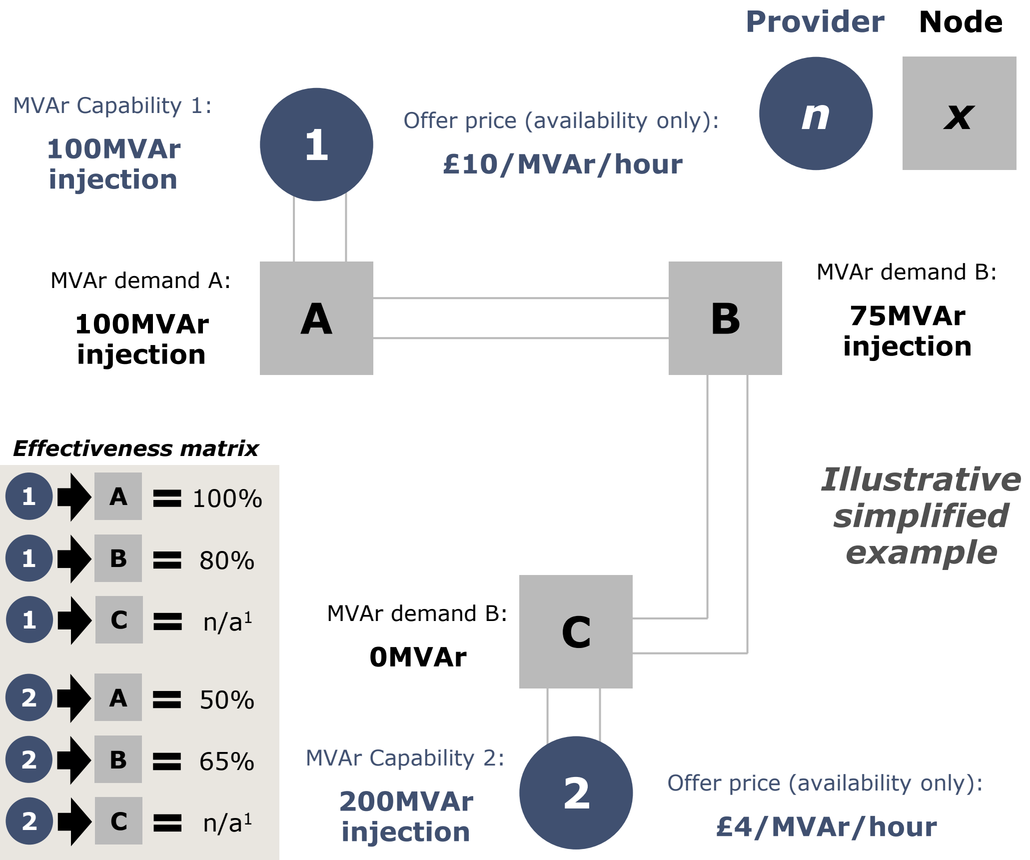
2. Establish effectiveness of providers



[1]Final solution must ensure compliance with voltage at node C (i.e. not causing overvoltage), however labelled as n/a due to zero demand.

Once needs are established, offers from providers must be collated and the desired solution identified

3. Collect offers from providers[1]



Effectiveness matrix

Provider	Node	Effectiveness
1	A	100%
1	B	80%
1	C	n/a[1]
2	A	50%
2	B	65%
2	C	n/a[1]

4. Clearing algorithm determines least cost solution[2]

1. Formulate constraints[3]

1. Transfer of reactive power from *provider n* to *node x* = Capability offered * effectiveness factor
2. Maximum capacity constraints for nodes established and applied (MVAr capacity at node X <= max)
3. MVAr supply at each node >= MVAr demand at each node (if feasible, otherwise maximise procurement)

2. Establish cost of each provider

Establish the cost of all providers (*note that the requirement to meet demand at all nodes is established in the constraints*)

1 = £10/MVAr/h*100MVAr=£1000/h

2 = £4/MVAr/h*200MVAr=£800/h

3. Minimise total cost[2] subject to constraints

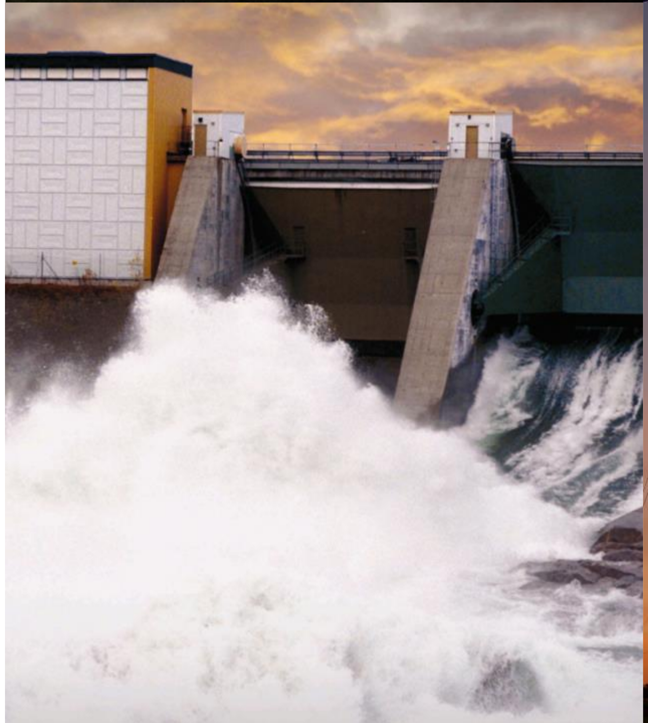
Algorithm selects bids to satisfy all constraints with objective function to minimise total costs, in this case:

1. Selecting either Provider 1 or 2 will satisfy the constraints
2. Whichever provider is selected, only the demand at node A is a binding constraint (the problem at node B is solved incidentally by both solutions)
3. Provider 2 is the cheaper option and is selected

[1]Simplified example – in reality need to collect offers for different products (inject/absorb pre/post-step), [2]Note that consumer surplus is implicit in bids, in a pay as bid market determining least cost solution is similar to maximising welfare, however the precise consumer surplus value is unknown [3]ignores polluting bids for simplicity

Agenda






Key messages

Utilisation costs are expected to **increase** over time and be a primary driver of future costs for reactive power (recovered by ESO)

The system is expected to continue **reliance on synchronising CCGTs** to access reactive power in the future under current arrangements

Where large reactive power requirements exist, **investment** in new assets can **reduce costs to consumers** but only if sufficiently **robust signals** are in place for participants to site their assets effectively

Introduction of **new routes to market** for MVAr only providers (or increased MVAr from existing providers) can significantly **reduce carbon emissions** related to reactive power

Offering a **short-term** route to market where providers are able to reflect their prevailing **opportunity cost of service** provision can **increase access to high effectiveness providers**, and reduce synchronisation costs – we expect this benefit to increase as capacity from new converter connected technologies grow

AFRY has modelled a nodal reactive power market to understand the potential impact of new market arrangements on service provision

Approach in a nutshell

2025 Leading the Way FES scenario (2021 edition, BID3)

FES scenario run with thermal constraints, demand/generation schedule, these form the inputs for the technical workstream methodology

Technical workstream (PowerFactory)

Key outputs from technical workstream including nodal demand for reactive (per product), nodal effectiveness of providers (per product), and provider MVAr capability

Reactive economic modelling workstream (BID3)

*Redispatch **volumes**, **costs**, and **carbon** emissions for meeting reactive power needs*

– AFRY has based analysis on ESO's **2021 edition** of the **'Leading the Way'** Future Energy Scenario. We have included a 'base case' redispatch including thermal boundary constraints so that we can later isolate the impact of voltage constraints on the modelling

– The generation/demand **schedule** has been provided to the **technical workstream** (mapping individual providers from BID3 electricity market model, to technical network model).

– The technical workstream team has undertaken analysis to determine the **MVAr need** for each product[1] at each node, and associated individual **provider effectiveness** for each product for each node.

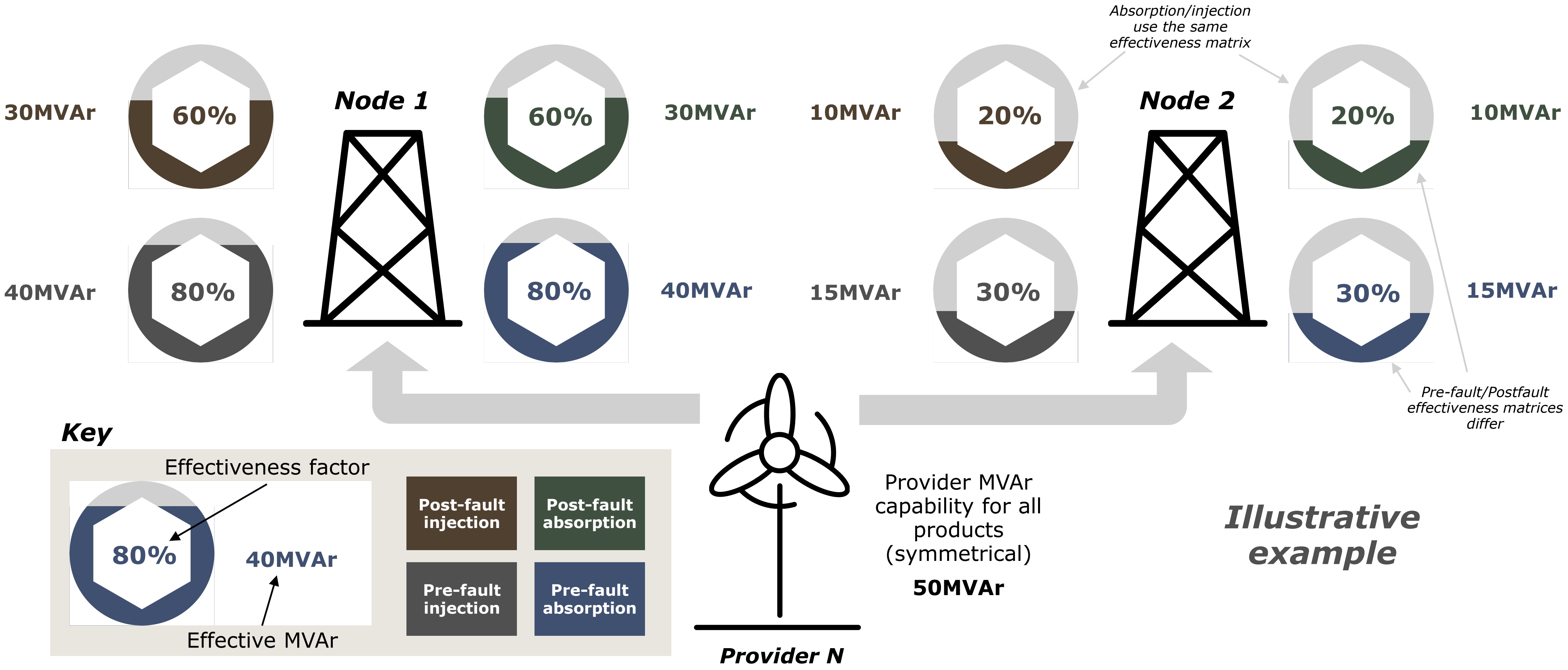
– AFRY has **defined nodal requirements** in BID3 for each product, represented as constraints in the model.

– AFRY has also defined corresponding **provider contributions** for each of the products – de-rating MVAr capability for providers by their effectiveness factor for each product for each node.

– BID3 is then re-run to **resolve voltage constraints** – redispatched **volumes**, associated carbon **emissions**, and **costs** are calculated.

Notes: [1]injection/absorption, pre/post-fault

Contributions for each provider, product, and node are defined in the model



Notes: Illustrative example, providers are paid based on MVArh output (rather than on effective MVArh delivered to every node) at ORPS rates based on ESO scenario prices

We have modelled multiple cases to understand the impact of various market design assumptions

Key scenarios

Status-quo

- Only build additional assets if needed to meet requirements *(none in case assessed based on average weather patterns)*
- Actions taken in balancing mechanism to resolve constraints

Long term market

- Additional solutions economics assessed for each node depending on costs incurred to resolve constraint
- New capacity assumed to be STATCOM[1]

Short term market

- Additional capability available from existing providers (in addition to long-term)
- Additional capability available assumed to be in line with market analysis case studies
- Access to additional capability assumed to have a MW/MVAr trade-off beyond ORPS ranges (opportunity costs optimised in model)

Key outputs

Redispatch volumes

- Additional generation due to plant being synchronised to provide voltage constraints.
- Curtailment/turn-down either to 'make room' on the system for reactive providers or due to MW/MVAr trade-off (short term market)

Voltage costs

- Costs for repositioning plant to provide reactive (either through BM or market arrangements)
- Costs for new investment (annualised)
- Costs for utilisation (ORPS or market)

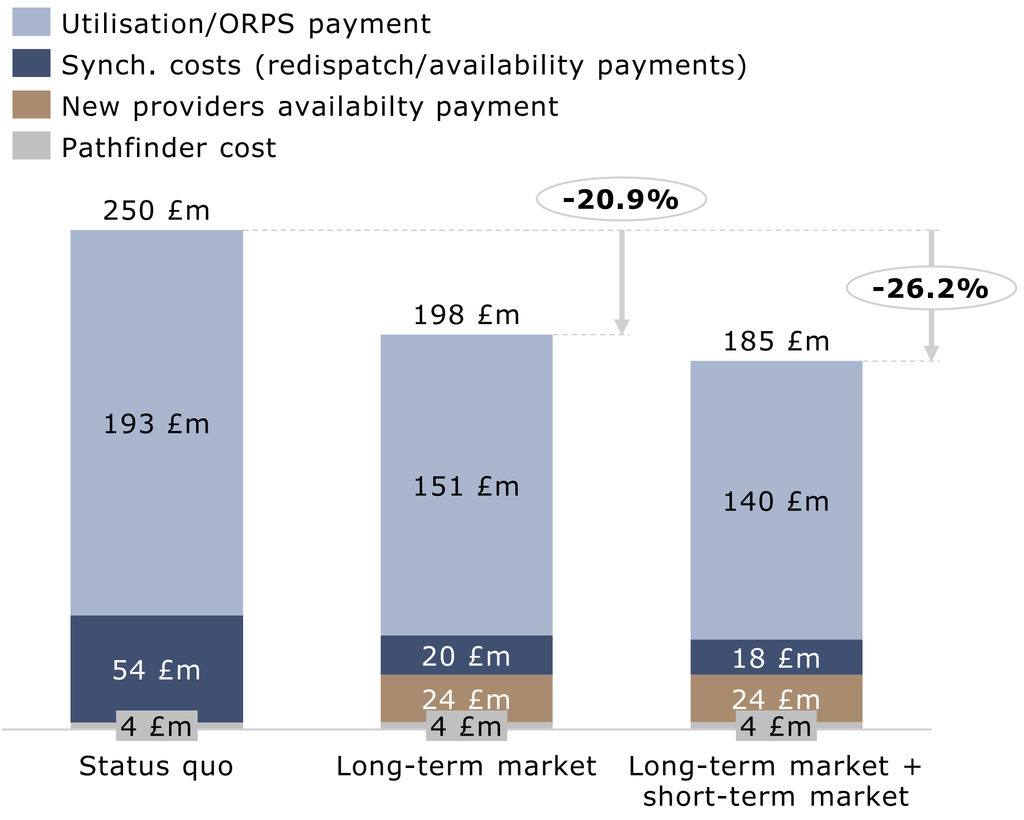
Redispatch emissions

- Additional emissions from:
  - repositioning plant in the BM
  - plant repositioning themselves when bid successful in (short term) reactive market; or
  - additional MW needed when plants operating outside of ORPS ranges

Notes: [1]This is conservative assumption, it may be that some needs can be met with cheaper solutions such as dedicated reactors/capacitors.

Significant cost benefits can be reaped through the introduction of a reactive market

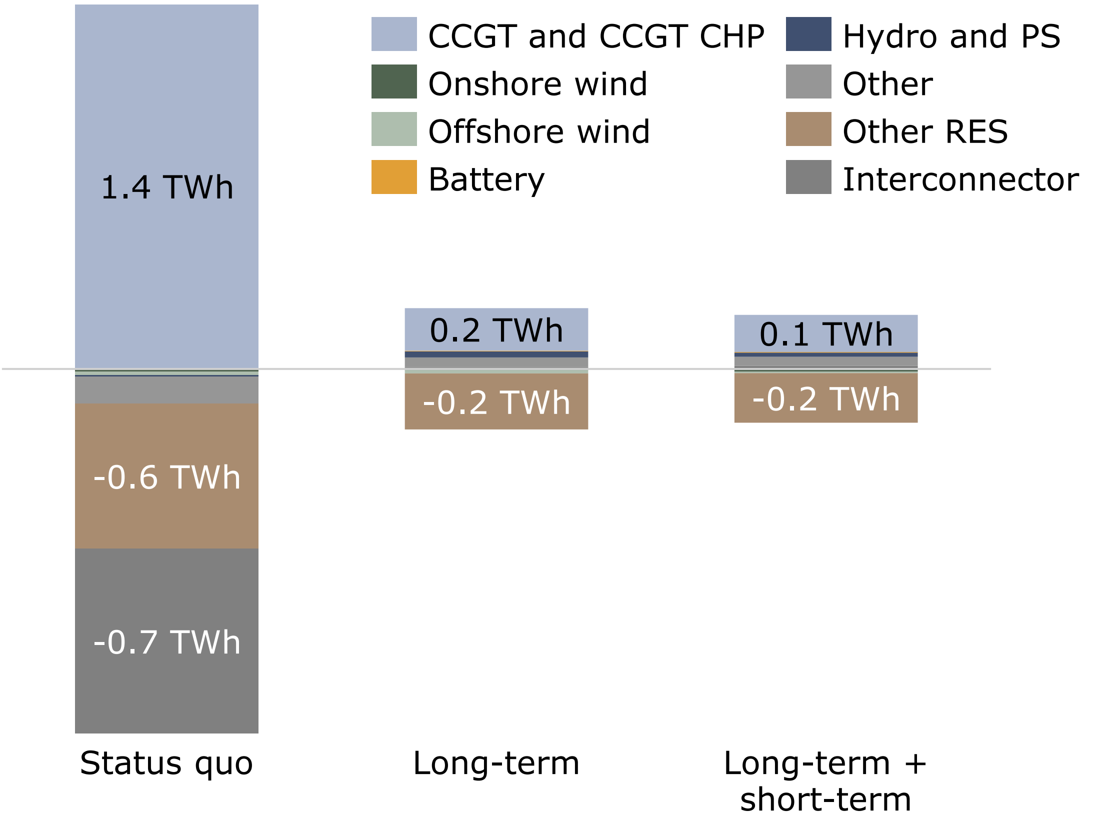
ANNUAL VOLTAGE COSTS (2025 LEADING THE WAY FES SCENARIO, £M, REAL 2020)



- **The voltage costs** are the sum of :
  - Costs for repositioning plant to provide reactive, either through BM or market arrangements (synchronisation cost on the chart)
  - Costs for utilisation (ORPS or market), £2.5/MVArh real 2020
  - Costs for new investment (annualised), from Pathfinders and additional STATCOMs from the long-term economic assessment
- The introduction of the long-term market for reactive power brings an economic benefit in terms of balancing and utilisation costs to meet voltage constraints. Compared to status quo, the long-term market would lower costs to meet voltage constraints by ~21%. This value is result of STATCOMs offsetting the need to pay ORPS providers for MVArhs, and partially offsetting the need to synchronise providers to ensure voltage stability
- The short-term market for reactive power brings further economic benefit beyond the long-term market. Being able to access providers extended range of MVAr capabilities reduces the need for balancing actions. It also allows for a more economically efficient dispatch (MVArh) of reactive providers, thus reducing the utilisation payments

The introduction of competitive provision of reactive power reduces the need for balancing actions to meet voltage constraints

REDISPATCH VOLUMES FOR MEETING VOLTAGE CONSTRAINTS (TWH)

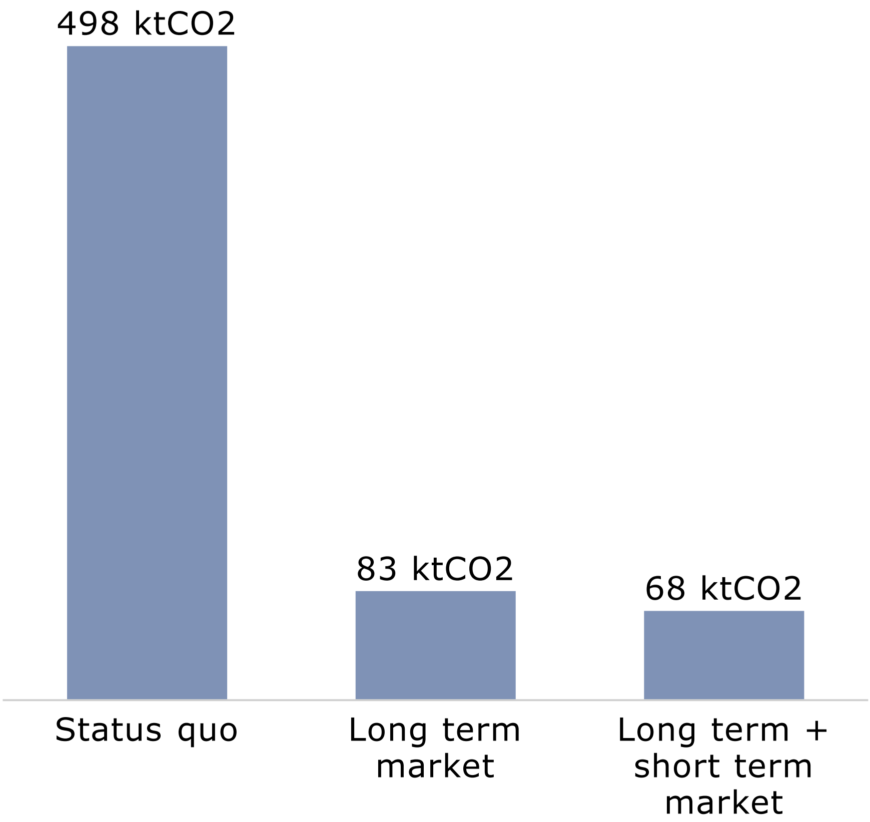


- The markets for reactive power reduce the **redispatch volumes** required
- With the introduction of the long-term market, the reduction in volumes can be attributed to offsetting the need to synchronise CCGTs to access reactive ranges
- These redispatch volumes are a significant proportion of the overall costs under the status quo, and their reduction in the long term market drives down both costs and carbon emissions
- In the scenario modelled, the reduced need to synchronise CCGTs increases the room on the system for renewable providers
- In the short term market, there is a slight reduction in overall redispatch volumes (albeit not as strong as in the long-term market), this is primarily driven by increased access to MVAr from existing providers, further reducing the number of instances in which CCGTs must be synchronised to meet reactive needs

*Difference between redispatch for 'only boundaries' and runs for both boundaries and voltage constraints

Reduced reliance on CCGTs for resolving voltage issues results in a reduction in carbon emissions overall

NET CARBON EMISSIONS TO MEET VOLTAGE CONSTRAINTS
KTCO2



- Under the status quo arrangements, CCGTs must be synchronised to provide reactive power services relative often, resulting in a net increase in carbon emissions of ~0.5mt/y
- The introduction of a long-term market results in new build grid assets offsetting the need to synchronise CCGTs to access reactive power ranges and substantially reducing carbon emissions associated with voltage issues
- This benefit is compounded with the introduction of a short-term market as additional MVAr available from existing assets results in even fewer periods where CCGTs need to be synchronised to provide reactive power

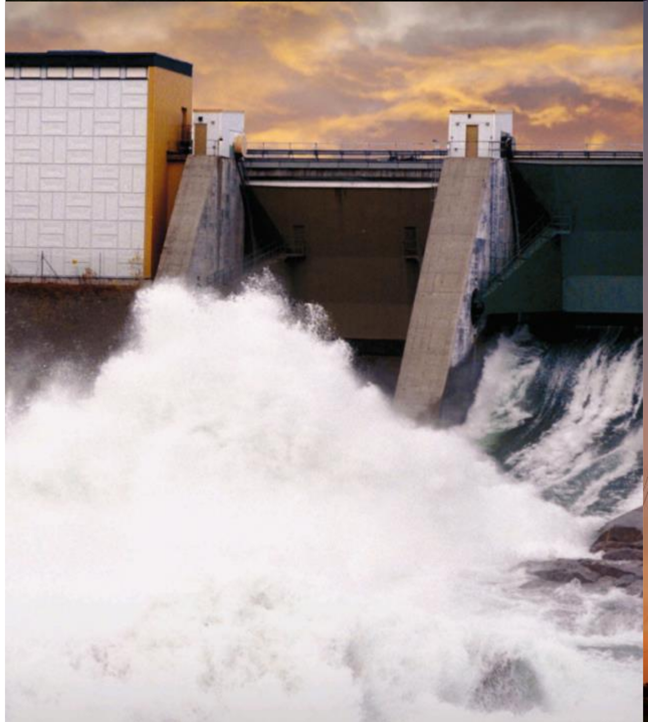
*Difference between carbon emissions for ‘only boundaries’ and runs for both boundaries and voltage constraints

There are a number of potential benefits that are difficult to quantify with limited information/data on potential future behaviour & limited model horizon

Modelling horizon limitations	– We are modelling a single year in relative close proximity to today (2025 modelled year). – Longer term trends may expose a greater need for services as increasing volatility of transmission system flows over time results in higher demand for reactive power.
Additional existing capability in a short term market	– There exists significant uncertainty as to how much additional capability can be exploited by existing providers to access additional reactive power services, ultimately our assumptions have been informed by our case studies.
Locational signals influence in ST market	– Locational price signals are likely to result in increased capability where it is most required, even from existing providers, as prices rise and incentives sharpen. – In our ST scenario we have modelled uniform increased capability across locations.
Specific interactions with existing arrangements	– In the short term, if there a risk of lost revenue for ORPS providers (e.g. if they are expecting to be less heavily utilised if not accepted), providers may bid negative availability prices in the short-term market to maximise gross margins. We have not considered this behaviour in the modelling.
Plant bidding behaviour in ST market	– We have based plant bidding behaviour for availability on bids/offers for different technologies in line with mechanism behaviour (and ESO standard scenarios). – It may be the case that short term bidding behaviour diverges in the future.
TO behaviour	– Exposure of TO providers to the risk of competition means there's a risk of non-acceptance, as a result TO provider may offer more competitive (lower cost) solutions than they would under the status quo, maximising benefits for consumers.

Agenda






This project has provided a recommendation for a new market design for reactive power, incl. market insight and tools to support the way forward

Market analysis

The project gives insight into the expected market size, location of reactive power providers and capabilities of different technologies. This insight has supported the work to design the proposed market, and should continue to inform and support decision making in the next phase of refining and implementing the market

DER participation

The report identifies key technical, commercial and regulatory barriers for DER to be considered and several possible ways forward on how to overcome these. The critical next steps involve changes impacting distribution network owners and will require a coordinated approach to implementation

Economic modelling

The economic modelling gives insight into the potential costs, actions, and associated carbon emissions for managing the system under ESO's Leading the Way FES 2021 scenario for 2025

This approach gives us views on the potential benefits of a competitive approach to reactive power, however it should be noted the modelling horizon is limited

Requirement setting

Defines nodal MVAr requirements; node-to-node effectiveness; and specific provider-to-node effectiveness.

Enables a consistent and repeatable way to produce market signals

Results can be sensitive to inputs (e.g. changes in network topology) and should be carefully calibrated based on ESO system operational views

Market design

Delivers the market framework appropriate to meet the challenges faced by both the ESO and providers. It should form the foundation for the way forward, towards the implementation of a desired end-state market solution

As part of this comes a detailed overview of procurement considerations, and prototype mathematical formulation of clearing algorithm objectives, which form the basis for development of a clearing algorithm

Key outstanding items for further consultation and analysis

Implementation readiness and cost

Gap analysis identifying ESO cost and effort to implement new systems and processes.

CBA and/or market trial

Potential for a market trial for ST market, and CBA analysis to be conducted once sufficient data gathered.

Design refinement

Considering feedback received so far in the process, we recommend further consultation with stakeholders to reach final conclusion on issues affecting practicality for participants and ESO (minded-to positions presented but confirmation needed).

There must also be further refinement of detailed design questions including 'incremental' criteria, specific penalty arrangements, settlement timing etc.

Participant readiness

Identifying any residual barriers and feedback in practical implementation aspects, incl. time & effort needed for integrating with new systems and processes. Continued dialogue with participants.

Ofgem review of ancillary service assets

Assess impact of Ofgem regulatory review of ancillary services assets (once complete) to ensure design compatibility.

TO participation

Refine approach to how TO asset cost data are assessed and included in the LT auction as back-stop.

Residual value TO assets

Further work to explore residual value of TO assets to ensure comparability with commercial providers, who have the opportunity to reflect their views on residual value implicitly through bids into the market.

Expired RAB assets

TO assets outside of their RAB period should be considered as a potential solution if economically efficient. This issue warrants further investigation.

Stacking services

Stacking and co-procurement, exploring potential benefits of co-optimisation with other services.

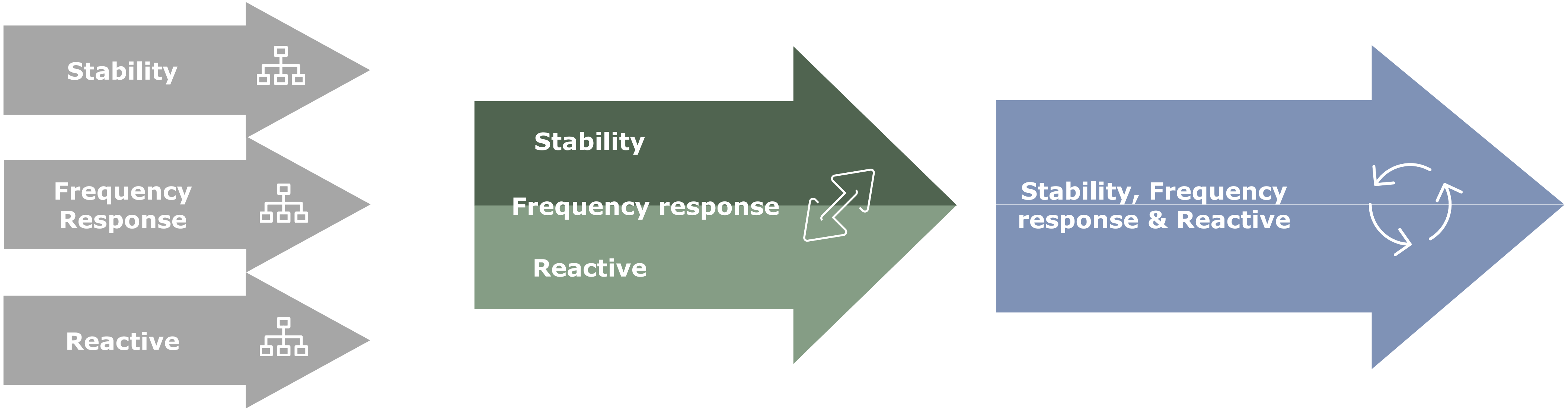
Regulatory protection

It may be desirable to investigate some form of regulatory protection from potential gaming.

DER participation

We have identified several next steps for the inclusion of DER in any enduring market arrangements. These critical next steps involve changes that will impact distribution network owners, and as such will require a coordinated approach to implementation.

There are multiple options for ancillary service markets with interactions, from separate procurement to full co-optimisation



Separate, fixed requirements

– Reactive power requirements are fixed and procured separately from other services that interact with it, such as inertia and frequency response

Separate, dynamic requirements

– Reactive power requirements are set dynamically, meaning the requirement is optimised as interaction between services is accounted for

– For example, ESO can choose to procure more inertia and less (or slower) frequency response

Full co-optimisation

– Full co-optimisation to maintain and limit frequency deviation

– Co-optimisation across all services that interact with each other could realise additional benefits through increased efficiency

Appendix

Definitions

Term	Example	Meaning
Contract (Delivery) Period	13:00 – 17:00 GMT 23rd May 2022, or; Jan 2023 – Dec 2038	The contract period of delivery during which the provider shall be available to deliver the full requested change of reactive power, injection or absorption.
Product (or contract) Duration	4 hour or 15 years	Defines the duration of a standardised product.
Frequency of procurement (market schedule)	Daily or annualy	Defines how often trading reoccurs.
Procurement lead time	16:00 GMT, D-1	Defines how far ahead of Delivery Period the trading happens (e.g. hours, days, months and/or years ahead). Same as Gate Closure Time, i.e. the deadline for submitting bids.
Market Time Window	24hours (00:00 – 23:59 GMT)	A fixed timeframe (ahead of time) for which products are open for trading at a given time.
Product	Pre-fault lagging	The definition of contracts/instruments available for trading. Products could differ by Contract Duration, Leading & Lagging and Static & Dynamic (depending on how we define products)
Contract (or instrument)	hh-230522-25-st-lagging	Is unique and specifies each specific contract being procured. E.g. specifying; time; direction (leading/lagging); and whether it is static or dynamic. Typically has a unique contract ID, see example which represent a half hour on 23rd May 2022, 12:00-12:30, static, lagging.
Market Time Unit (MTU)	30min	The most granular Product Duration. Also the period for which the market price is established.
Product linking		In case of multiple type of products being procured at the same time, 'linking' allows provider to offer a linked combination of products. Typically used to link leading and lagging into one offer. Normally non-mandatory.
Opportunistic buying		Additional volume (above shortfall/gap) to be procured if economically efficient (expected future cost savings relative to procuring in subsequent timeframes).

Definitions

Term	Example	Meaning
Availability		Availability is defined as the availability to deliver reactive power at some point in the future. The utilisation price can be defined as part of the availability contract or otherwise (including zero). Commitment may be firm or non-firm (see below).
Utilisation		Utilisation is defined as the delivery of reactive power (leading/lagging) to the grid in line with dispatch instructions by the ESO
Availability requirement	95%	No assets can provide 100% availability over a long period, e.g. a year. Therefore, *firm* long-term availability markets should have a predefined availability requirement, to allow for outages.
Firm contract		Seller guarantees continuous availability (subject to contracted availability requirements) and failure to deliver would trigger a financial and/or legal liability claim. It provides the buyer (NGESO) the assurance that future voltage security is covered, but the nature of the contract prevents intermittent renewables such as solar and wind from participating in long term contracts, thus limiting the level of competition.
Non-firm contract		Contracts comes without a guarantee of continuous availability. They may be interrupted for any reason, without liability to NGESO. The provider is guaranteed a price if providing services, e.g. utilisation and/or short-term availability payment.
Outside option		In the context of this project, ‘outside option’ refers to the Transmission Owner solution cost counterfactual. This is considered to be an outside option because, whilst solution costs are assessed as part of the bid selection (winner determination) process, a contract is not ultimately awarded. An STC planning request is triggered and the TO is instructed to build the asset which then forms part of the relevant TO’s Regulated Asset Base. This is compatible with current arrangements and has been informed by learnings from the Pathfinder projects, but may be subject to change in the future.
Shortfall/gap		The shortfall in the context of this project is the difference between what is required to meet reactive needs, and what is already committed (either contracted or TO assets) + capability that will be available in subsequent timeframes. The shortfall is contracting additional capability that would not otherwise be available in subsequent timeframes.

Glossary

Acronym	Term	Meaning
ESO	Electricity System Operator	National Grid ESO – the system operator in Great Britain
TO	Transmission Owner	Collective for the companies which own the transmission network in GB
DSO	Distribution System Operator	Collective for the companies which own and operate the distribution networks in GB
OFTO	Offshore Transmission Owner	Collective for the companies which own offshore transmission infrastructure in Great Britain
GSP	Grid Supply Point	Connection Point at which the Transmission System is connected to a Distribution System
ORPS	Obligatory Reactive Power Service	Obligatory service to provide reactive power services as specified by the grid code
RIIO	Revenue=Incentives+Innovation+Output	Framework for network company remuneration in Great Britain
SP	Settlement Period	A period of 30 minutes beginning on the hour or the half-hour
SQSS	The Security and Quality of Supply Standards	Obligations on licensees to provide
STC	The System Operator-Transmission Owner Code	Defines the relationship between the transmission owners and the system operator incl. roles and responsibilities
MVAr	Mega Volt Ampere Reactive (Capacity)	Measure of capacity for reactive power
MVArh	Mega Volt Ampere Reactive hours (Volume)	Measure of volume for reactive power
DER	Distributed Energy Resources	Energy resources including generation, demand and storage connected to the distribution network

Glossary

Acronym	Term	Meaning
ESQCR	Electricity Safety Quality and Continuity Regulations	Governs the required quality of electricity supply in GB
NOA	Network Options Assessment	ESO assessment process for grid reinforcement
ETYS	Electricity Ten Year Statement	ESO view of transmission requirements for the next ten years
RAB	Regulated Asset Base	Regulated framework for cost recovery
CfD	Contracts for Difference	Low carbon support scheme in GB
CM	Capacity Market	Mechanism for renumerating capacity in GB


AFRY
Making Future
AFRY
ÅF PÖYRY