nationalgridESO

Our Forward Plan 2019-21

28 March 2019

Our Forward Plan 2019-21

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Appendices

As the System Operator for Great Britain, we are privileged to sit at the heart of the nation's energy system, running the gas and electricity networks safely and efficiently while enabling and accelerating progress towards a low-carbon energy future. This also means that, together with our stakeholders, we are responsible for tackling some of Great Britain's most pressing energy challenges.

The world of energy is undergoing fundamental transformation. Cleaner forms of energy like wind and solar are increasingly replacing traditional fossil fuel generation; energy storage is becoming mainstream and consumers are increasingly becoming more active in making energy choices, for example through the electric vehicles (EVs) and solar panels they buy.

Those changes will continue as the industry evolves over the next decade towards 2030 and beyond. They will present huge challenges for the infrastructure and security of energy supplies, which lie at the heart of our role as Great Britain's System Operator – and we too will need to evolve to meet these challenges if we are to remain at the heart of Great Britain's energy system.

Working together as an industry, we can shape the future of energy. The System Operator is publishing three documents as a result of stakeholder engagement. These documents set out what we believe the future of the whole energy system will look like, and what we are proposing to deliver for consumers, across three different timeframes.

- Our **Towards 2030** document sets the scene with a high level long-term view of the energy landscape in 2050 and the whole energy system and its enablers for 2030. It also sets out the SO's high-level ambition for gas and electricity, from now until 2030.
- **Our RIIO-2 Ambition** is a consultation that sets out our ambition for the ESO and a first proposal of our activities for the next price control (from 2021 onwards). Our ambition is dominated by four themes that build on our current roles and reflect the feedback we have heard from stakeholders over 18 months of extensive engagement. Sharing our ambition, our work to date and inviting further views will help us prepare an informed and robust business plan later in 2019.
- Our **2019-21 ESO Forward Plan** sets out our immediate steps until the start of RIIO-2 to achieve our ambitions as set out in the Towards 2030 document. It details our deliverables, performance metrics and how the outcomes we drive deliver consumer benefit. This is the finalised product of deep engagement with our stakeholders; this plan will be refreshed for discussion with stakeholders in January 2020.

How to use this document

We present our 2019-21 plans against three role areas: manage system balance and operability, facilitating competitive markets and facilitating whole system outcomes & supporting competition in networks. Within each role chapter, we share: our long-term vision and how this delivers benefits for consumers, the activities we will deliver during 2019-21 and performance metrics to track performance between 2019-20. To support this, we include four appendices: (A) a summary of the Incentives Framework, (B) summary deliverables and metrics tables (C) consumer benefit case studies and (D) a summary of how we have responded to consultation feedback.

Fintan Slye

Director of UK System Operator

2030: a time of transition

What will the world of energy look like by 2030? Let's fast forward to what we believe will be a critical period for us.

We are supporting the fundamental change across industry that is required to thrive in this new environment, driving innovation and harnessing emerging technologies to deliver flexible and responsive infrastructure and meet the challenge of decarbonisation head on.

Increasingly, we no longer think in terms of gas and electricity as separate systems; we plan and manage our networks to be smarter, welcoming new players who want to connect to the networks, providing a transparent and efficient market-driven environment where everyone can contribute to the new world of energy.

In the background, energy policy is changing as government focuses on its environmental targets. New market regulations are coming into play with much stronger emphasis placed on flexibility, reliability and competition.

The impact on system operation is enormous. And we will play a crucial role in delivering the new energy landscape, although we cannot do it without cross-industry collaboration and the innovation and expertise of our stakeholders and partners.

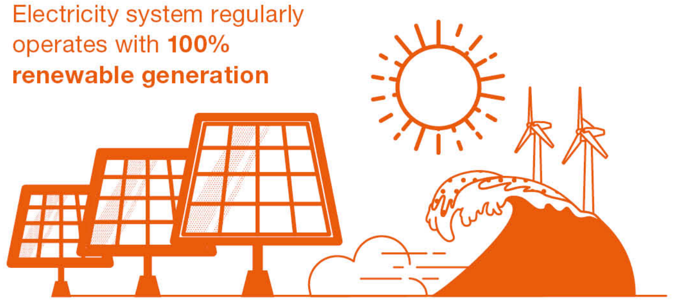
Delivering value with a smart, flexible whole energy system:

Between £3.2 billion and £4.7 billion of benefit could be realised per year, through integrating high levels of flexibility such as interconnectors, demand-side response and storage across the whole energy system.

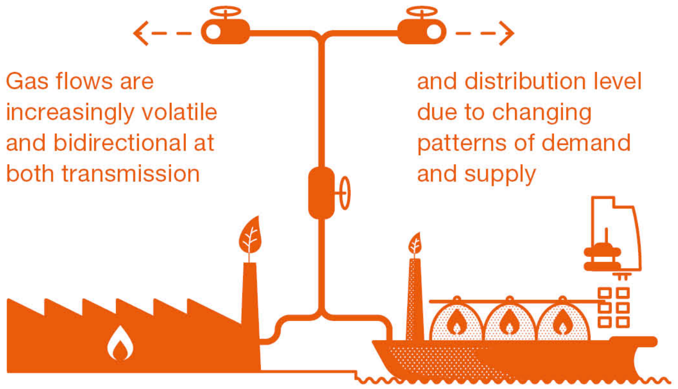
This will require a deep understanding of the capability of our network infrastructure. It will also require flexible and intelligent operation across all networks, with market mechanisms which are open to any asset or service which can support grid stability and security.

(Roadmap for Flexibility Services to 2030, A report to the Committee on Climate Change, May 2017)

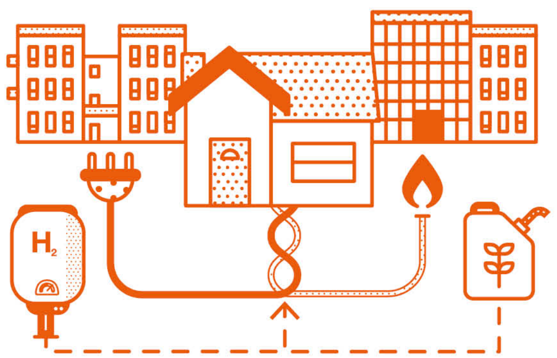
Competitive markets are designed and operated to ensure efficient and reliable operability, balancing supply and demand across gas and electricity systems



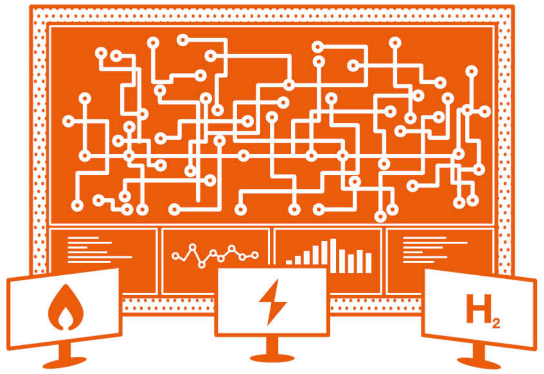
Electricity system regularly operates with **100% renewable generation**



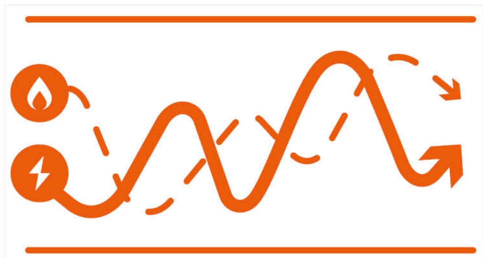
Gas flows are increasingly volatile and bidirectional at both transmission and distribution level due to changing patterns of demand and supply



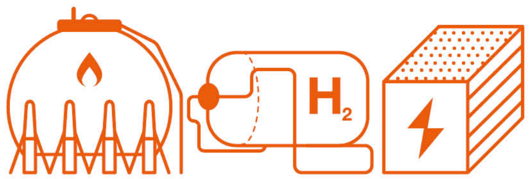
Network operations, planning and investment
Smart flexible networks, intelligent monitoring and commercial solutions enable optimisation of planning and investment across the whole energy system



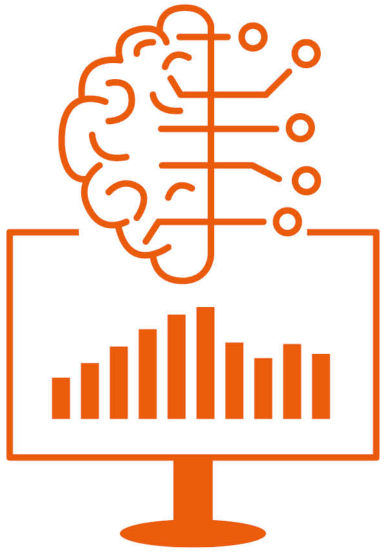
All networks are actively managed
Distribution system operation is the norm and all networks are actively managed in real time



Risk and resilience is managed across the whole energy system. System event readiness, management and recovery is integrated across transmission and distribution networks for gas and electricity

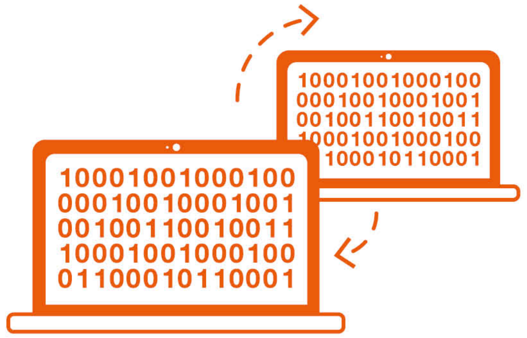


Large volumes of
long-term energy storage



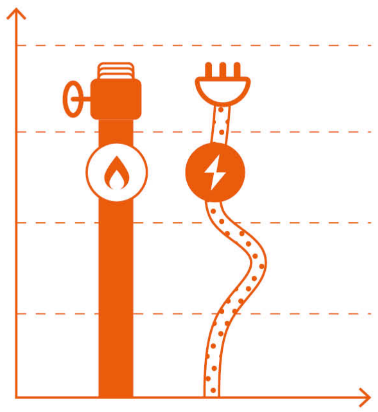
Artificial intelligence and machine learning are commonplace across all players in the industry, including vehicle charging, appliances, market participation and system operation. Critical functions such as system balancing always have human involvement

New commercial frameworks and markets will support whole system flexibility and operability, as well as potential new vectors (hydrogen, CO_2)



Data is shared openly wherever possible to inform competitive and efficient markets, enable innovation and inform change across industry

Policy direction on the decarbonisation of heat has been set and the first commercial deployments of new technology will be rolling out



Consistency across networks for customers
Consistent and co-ordinated customer connection process across transmission, distribution, gas and electricity networks

Connection requirements are aligned across transmission and distribution networks

Codes, frameworks and governance that facilitate competitive and efficient markets as the pace of change increases and the number of market participants grows

Doing more with less: operating the whole energy system with open, efficient markets:

Active distribution system operation and the optimisation of planning and investment across the whole energy system will reduce consumer cost by minimising the need for network build. It will also open up markets to a larger and more diverse range of flexibility providers, such as low-carbon generation, improving liquidity and efficiency of markets. Overall, this will lower bills and reduce environmental damage.

Our SO mission

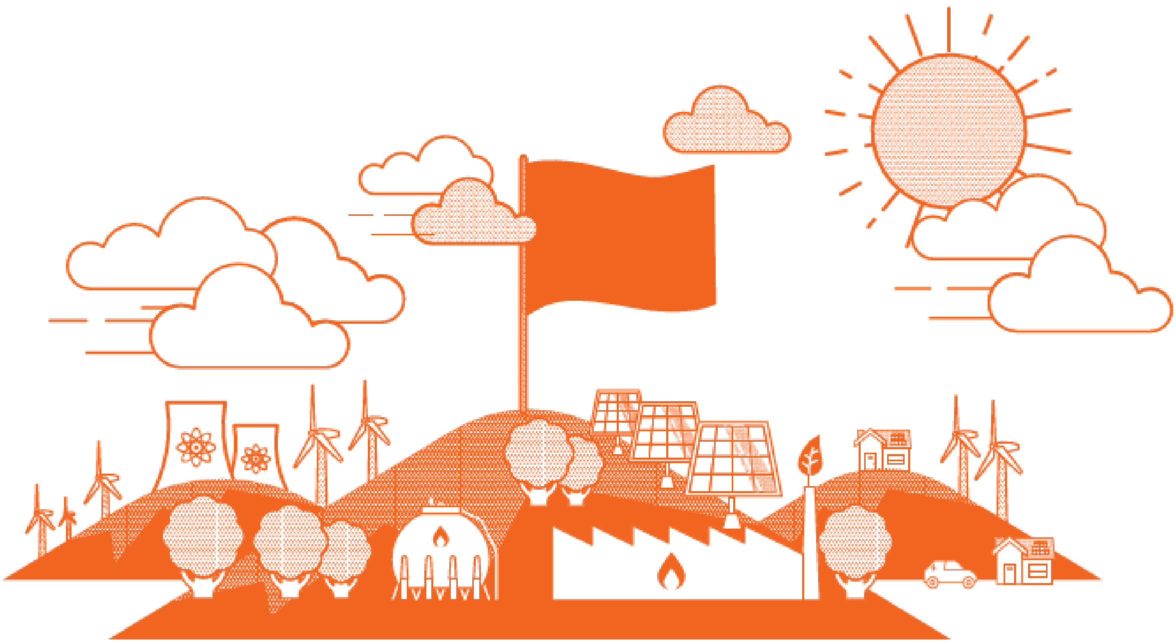
Our Mission is to enable the transformation to a sustainable energy system and ensure delivery of reliable affordable energy for all consumers.

Success in 2025 looks like:

- An electricity system that can operate carbon free
- A strategy for clean heat, and progress against that plan
- Competition everywhere
- The System Operator is a trusted partner

To achieve our mission, we have set out five priority focus areas for the SO to guide us in this journey:

1. The engineering transformation: ensuring reliable, secure system operation to deliver energy when consumers need it
2. The market transformation: unlocking consumer value through competition
3. The sustainability transformation: enabling and supporting the drive towards a sustainable whole energy future
4. The smart transformation: driving innovation and increased participation across the energy landscape
5. The capability transformation: developing the right people and systems to deliver the future



Delivering Consumer Benefit

In all that we do, our mission is to deliver most benefit for consumers and while we don't have direct contact with consumers, they benefit from our activities in five ways:

Improved safety and reliability

The on-demand provision of electricity is a fundamental part of our modern life which must be continuously attended to with the utmost importance by the Electricity National Control Centre (ENCC) and supporting functions. We will continue our focus on system balancing and security at optimum cost in line with the expectations that Government, the regulator and the consumer have of us. We look further ahead, to ensure we can operate the system in the future, as it rapidly transforms with low-carbon, intermittent, non-synchronous and distributed generation sources.

Improved quality of service

Over recent years we have transformed our approach to engage deeply with all our stakeholders, listening to what they want from us, and delivering on that where we can, and where we cannot, explaining why. This rich stakeholder input has shaped how we do things and put much more of a focus for us on why and how we can improve our quality of service. Improved service quality ultimately benefits the consumer due to interactions in the value chains across the industry being more seamless, efficient and effective.

Lower bills than otherwise the case

We lower consumer bills by working to control, reduce, and optimise elements of the system charges which we can impact and influence. Theses charges are the Balancing Services Use of System and Transmission Network Use of System charges (BSUoS and TNUoS). These charges are levied on suppliers and transmission-connected generators, and passed through to end-consumers. We optimise across BSUoS and TNUoS linking our balancing decisions with our ***Network Options Assessments (NOA)*** so that in the long-term the economic and efficient outcomes are being driven when planning, developing and investing in the network. Nearer to real time we manage BSUoS by focusing on controlling, reducing, and optimising our spend on balancing and operating the system. These charges flow through to the consumer bill from suppliers, therefore any reduction of this cost (approximately £1 billion of BSUoS and £3 billion of TNUoS per annum) will benefit the consumer.

Reduced environmental damage

Great Britain has committed to reducing its CO2 emissions year on year, and as the ESO we are at the centre of the transition to a low-carbon electricity system.
We therefore support new providers and technologies to enter and compete in the existing and new markets basing our decisions on the technical capabilities of providers. We also work innovatively to design novel solutions which ensure the system can operate safely and securely both now and in the future with large levels of intermittent and non-synchronous generation running. We are committed to being 'technology neutral', as market participants already have environmental costs priced into their products and services, for example through carbon price levies. We will not choose to procure from providers based on the fuel they use to generate power.

Benefits for society as a whole

By 2050, energy system decarbonisation efforts could add 19 million jobs and $52 trillion of gross domestic product (GDP) to the global economy, increasing the GDP of Northern and Western Europe by 1.25% and 2.5%, respectively. It could also generate a 15% increase in global welfare and reduce negative health effects caused by local air pollution by 60%.

Within Appendix C we have provided case studies, where appropriate, of how our activities deliver consumer value now and in the future.

2019
Forward Plan

2021
RIIO-2

2030

Our Mission is to enable the transformation to a sustainable energy system and ensure delivery of reliable affordable energy for all consumers.

Success in 2025 looks like:

- An electricity system that can operate carbon free
- A strategy for clean heat, and progress against that plan
- Competition everywhere
- The system operator is a trusted partner

Share our unique energy perspective through our **Insights documents.**

Increase **information access** by developing a user-friendly self-service information portal.

Provide greater **transparency of data used by our ENCC**, sharing operational planning data as we prepare the ENCC for the future.

Deliver an **Energy Forecasting** Strategy roadmap increasing the number of forecasts provided.

Address current and future **operational issues** identified by our Operability Strategy Report.

Share greater information on how we balance the system and provide our **operational insights.**

Actively **managing balancing costs** against a backdrop of decentralisation, decarbonisation and digitisation.

Upgrade of information systems including Energy Forecasting System, Ancillary services dispatch platform.

Transform the operation of the electricity system so that, by 2025, we will be able to operate a carbon free electricity system.

Provide greater transparency of our selection and utilisation of resources.

Transform the data we make available by providing a clear interface to all ESO data so it can be easily accessed and interrogated.

Deliver an auction platform for procurement of **frequency response.**

Fundamentally review and reform our **response and reserve products** to align with future operability needs and EU standard products.

Increase the transparency of our **reactive** power procurement.

Promote industry development of demand side flexibility via **Power Responsive.**

Enable wider access to **Balancing Mechanism**.

Develop new approaches to system **restoration** (also referred to as Black Start capability).

Transform the **customer experience** for network charging.

Facilitate electricity network charging reform through **Charging Futures.**

Facilitate **code change** to enable all network users to understand and contribute to the code change process.

By 2023 all market participants 1MW and above will be able to participate directly in our balancing service markets and the Capacity Market.

By 2025 we will deliver security of supply against a clear standard agreed with Government. We will be responsible for all elements of the Capacity Market.

A sandbox market environment will sit alongside our established markets to enable co-development of solutions to operability issues such system inertia and stability.

Create a fully digitalised Grid Code which is principles-based, simple to understand and navigate, and enables the flexibility required to support the energy transition.

Transform **industry frameworks** to enable decentralised, decarbonised and digitalised energy markets.

Making **Electricity Market Reform** easier for participants

Ensure a whole system approach is taken to optimise planning development, investment and operation of GB's energy networks.

Bring our expertise to drive industry as it navigates a complex energy transition, facilitating informed whole system thinking.

Reduce friction for participants in their interactions anywhere on the electricity network.

Implement a first of a kind system to measure system inertia in real-time and use it to optimise real-time **operation, service procurement and network development.**

Identify operability solutions as an alternative to network asset solutions through our **Regional Development Programmes.**

Provide **whole electricity thought leadership**.

Identify opportunities to more flexibly operate the network and further roll out enhanced **whole system data exchange.**

Facilitate competition across all dimensions – enabling all viable options to compete for delivery of solutions to network problems.

Actively support Ofgem and industry to deliver a model for onshore competition that maximises consumer benefit.

Use **enhanced study tools** to assess the year-round transmission network needs.

Lead **pathfinder projects** to develop the necessary processes to support delivery of new whole system ways of working.

Manage system balance and operability

Facilitating competitive markets

Facilitating whole system outcomes

Competition in networks

How our plan has evolved

In January 2019, we consulted on our draft Forward Plan, seeking input on whether our plans are heading in the right direction to meet current and future market needs and if we are targeting the right activities to deliver most benefit for consumers. We are grateful for the stakeholder feedback we received; this has helped to shape our final Forward Plan. Using stakeholder feedback, we have made changes to the structure of the document: using roles instead of principles, provided greater detail on how we will deliver consumer benefit and why our activities exceed baseline expectations; more detail on these changes are provided below. As we begin delivery against this plan in April 2019, we continue to welcome stakeholders to discuss and challenge our plans to ensure we continue to deliver the right activities that deliver most benefit for consumers.

Structure of the document

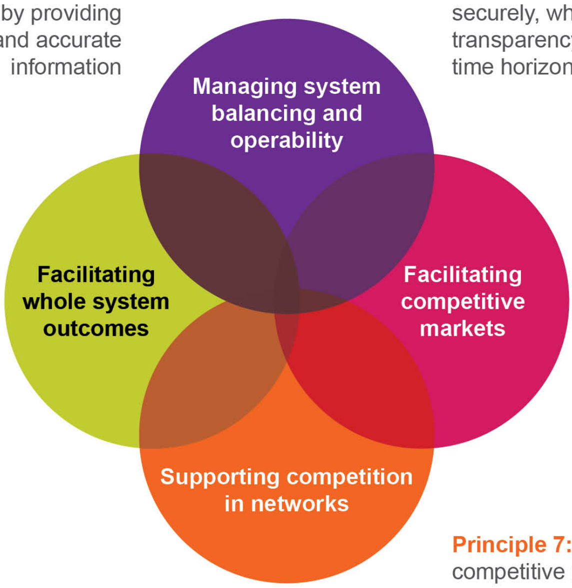
In April 2018, Ofgem introduced a new ESO incentives framework for the period of April 2018-March 2021[1]. Throughout the first year of the scheme, we have continuously discussed the lessons learnt of the scheme with Ofgem. Following Ofgem's Call for Input in October 2018[2], we have discussed how we use the roles and principles to share and report against our plans. As per Ofgem's Electricity System Operator Reporting and Incentive Arrangement guidance document (ESORI) consultation[3] outcome, we have presented our Forward Plan against the three roles areas; this sees facilitating whole system outcomes and supporting competition in networks under one role area. In doing this, we stress that this has not changed the content of our plan, all deliverables included in the consultation plan remain however we believe presenting against the three roles areas, we believe, allows us to better present our long-term vision and how we deliver benefit for consumers.

Principle 1: Support market participants to make informed decisions by providing user friendly, comprehensive and accurate information

Principle 2: Operate the system safely and securely, whilst driving overall efficiency and transparency in balancing strategies across time horizons

Principle 5: Coordinate across system boundaries to deliver efficient network planning and development

Principle 3: Ensure the rules and processes for procuring balancing services, maximise competition where possible and are simple, fair and transparent



Principle 6: Coordinate effectively to ensure efficient whole system operation and optimal use of resources

Principle 4: Promote competition in the wholesale and capacity markets

Principle 7: Facilitate timely, efficient and competitive network investments

How we are exceeding baseline expectations

At the start of each role chapter, we have provided more detail on why we believe our activities go beyond the baseline expectations of an efficient and competent ESO. We have removed the column from our deliverable tables called 'meeting or exceeding baseline expectations'; we want

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[1] https://www.ofgem.gov.uk/system/files/docs/2018/02/policy_decision_on_electricity_system_operator_regulatory_and_incentives_framework_from_april_2018.pdf

[2] https://www.ofgem.gov.uk/system/files/docs/2018/10/call_for_input_on_2019-20_eso_incentives_framework_final.pdf

[3] https://www.ofgem.gov.uk/system/files/docs/2019/02/final_consultation_on_changes_to_2019-20_eso_incentives_framework.pdf

to be clear that we do not believe a single deliverable in its own right is exceeding. We believe that we exceed baseline expectations through the 'what' and 'how' we deliver activities which collectively achieve an outcome that unlocks additional benefit for consumers.

As mentioned within the ESORI, a level of judgement is required when defining activities as exceeding baseline expectations, we hope the addition detail we have provided will help to inform stakeholders why we believe our activities are exceeding baseline expectations and deliver additional benefits for consumers.

What does exceeding baseline expectations mean?

Ofgem's ESO Reporting and Incentives Arrangements document defines exceeding as 'clear and tangible evidence of the ESO taking new steps within that year to deliver better practices, business models and technologies that would not normally be expected by an efficient and competent system operator. These steps should lead to material improvements in the ESO's performance and unlock additional consumer benefits.

In practice, defining baseline expectations for each area of activity will likely require an element of judgement. For many of the outcomes we expect from an organisation like the ESO, data driven targets are either very difficult to derive or are subject to wider factors that make them unreliable in isolation.

Delivering consumer benefit

In our draft Forward Plan, we presented how our activities deliver consumer benefit against five categories: improved safety and reliability, improved quality of service, lower bills than would otherwise be the case, reduced environmental damage and benefits for society as a whole. Within our role chapters, we have explained how delivering against our long-term vision unlocks consumer benefit and how the activities that we are delivering in 2019-21 support this vision and delivery of benefits. Given the broad range of benefits that we deliver, it is challenging to provide quantitative explanations of how all of our activities deliver tangible impacts on the consumer bill. Where we believe it is possible to use a quantitative approach to estimate how activities deliver benefits we have provided case studies within Appendix C.

Performance Metrics

For several metrics, we have provided additional detail on how our benchmarks have been set and based on stakeholder feedback, we have revised our benchmarks since our draft publication. For roles 3 & 4, we have added two new metrics: metric 12 – customer value opportunities and metric 16 – enhancing communication. We welcome further stakeholder feedback on all metrics throughout April 2019 ahead of the publication of our first FY19-20 report in May.

Innovation Funding

Within Appendix A we have identified projects that have received innovation and how our activities go beyond those required by the innovation funding.

Summary of key changes since our draft publication

Role 1	• Included additional deliverables including procurement guidelines. • Removed FFR information provision improvement metric and have included into the Information provision scorecard. • Updated the targets for the forecasting metric and more clearly explained the accuracy measure. • Provided further details on how metric 1 – balancing cost management was created and supporting clarification of these costs. • Provided more clarity around the open data deliverables for next year and how these evolve with our RIIO plans.
Role 2	• Provided greater clarity on our long-term vision and the benefit this will deliver for consumers. • Revised our performance benchmarks on metric 4 – provider journey feedback. • Included additional information on our performance benchmarks for metric 5 – reform of balancing services. • Revised our performance benchmarks on metric 6 – code administration: stakeholder satisfaction.
Role 3 & 4	• Provided greater clarity on our whole system ambition across investment, planning and operations and connections and how our activities are driving towards this ambition. • Included additional deliverables including deeper system access planning. • Introduced two new metrics: metric 12 – customer value opportunities and 16 – NOA: enhancing communication. • Provided more clarity on the scope and benchmarks of metric 15 – NOA consumer benefit.

1. Managing system balance and operability

Role 1 Managing system balance and operability

Operate the system safely and securely, whilst driving overall efficiency and transparency in balancing strategies across time horizons

Support market participants to make informed decisions by providing user friendly, comprehensive and accurate information

Long-term vision

As we transition to a low-carbon energy system, our operating environment is changing dramatically and at pace. The number and diversity of market participants is increasing rapidly and information on market positions and system conditions is moving closer to real time. We are seeing ever greater volumes of less predictable renewable and distributed sources of electricity generation. Through our system operation and balancing role, we manage around £1 billion of cost per year and have held this broadly steady, despite the increasingly challenging environment.

Since the start of the previous price control we have seen unprecedented change in the energy landscape. For example, at the start of RIIO-T1 we forecast that in 2019 we would have around 1 gigawatt (GW) of solar power capacity in the UK; we now have over 12 GW. Wind levels have similarly risen from 3 GW to 15 GW in the last 10 years as we transition to an increasingly decarbonised system. Managing this uncertainty, together with declining system inertia, has a significant impact on how we operate the system.

The adoption of new technologies, such as electricity storage, and the increasing need for distribution system operation, will require new operational processes across the transmission-distribution boundary. The continued expansion in the number of market participants will increase the volumes of technical and commercial data to be analysed and exchanged with other system users.

Under this role, our vision is to drive overall efficiency and transparency in balancing, taking into account impacts of our actions across time horizons. Looking to 2030, we need to find the optimum way of carrying out balancing and operability actions in a low-carbon, decentralised and digitised world. We will act as residual balancer, taking actions needed to balance and operate the system efficiently, ensuring stable balancing costs amongst a world of change.

As energy resources connecting across the system change, through new interconnectors and low-carbon generation, new questions arise on how to best operate it. A new and widening range of potential providers, connecting across transmission and distribution, are placed to answer these questions. We must continue to match the outcomes we need to deliver, with the services we can procure from the growing market. To achieve this, we will maintain our focus on operating the system safely, securely and efficiently. We will coordinate new and existing requirements through transparently developed systems which are fit for the future. We will support integration of new and existing resources by enhancing our existing IT systems and delivering new ones as needed. We will share our thinking on where changes may be needed to balancing services and codes. We will listen to our stakeholders to ensure we benefit from their experience and ideas as we form our views.

A key aspect to this is that we want to be a transparent ESO providing accurate information to help market participants make informed investment decisions and facilitate the transition towards balancing across shorter timescales. We are committed to improving the user experience in everything we do. Alongside this we want to improve confidence in our forecasts, increase transparency of our balancing actions and provide more comprehensive information which is accessible to all.

Delivering consumer benefit

Life in 2019 is dependent on electricity, so when we do our role well we are invisible to consumers. We balance the electricity system and keep it operating safely, securely 24/7 at efficient cost. We anticipate the increasing importance of keeping the lights on as the energy sector continues to transform. Without intervention, decarbonisation and decentralisation of generation combined with changes in how energy is consumed and the required infrastructure changes needed will see the cost of balancing increase. We will act in the short and long-term focussing on delivering consumer benefit through managing down the expected increase in balancing cost. This cost is paid through the BSUoS levy on suppliers and transmission-connected generators.

In the short-term, we will provide comprehensive information for market participants. They can use this information to offer market products which fit with system requirements. To drive price competition, we and industry can create alignment of theses market products to the services that we need, where and when we need them.

In the long-term, we will continue to identify future operability challenges in advance and communicate this to the industry. We will then share our market and technical proposals for how to address these; giving market signals so that we can secure the system at optimum cost.

We can lower BSUoS costs by working to drive down the price we pay for balancing services through better functioning and more efficient markets; we do this by focusing on the information we provide to the market participants.

This benefits markets in operational timescales, and will also help enable investment decisions. Leading to increasing market competitiveness, deliver new generation which assists with system reliability and reduce environmental damage where the new generation is low-carbon.

Focusing on the areas above will drive down BSUoS costs to be lower than would otherwise be the case. The high-level outcomes we are targeting can be summarised as:

- Safe, secure, and economic uninterrupted system operation in all timescales.
- Awareness of current and future operability challenges, informing short term investment strategies, and commercial and operational plans.
- Better informed decisions taken by market participants.
- Greater understanding of system operation and our needs.
- Reduced uncertainty for market participants.

Role 1 Manage system balance and operability

Focussing on efficent and transparent balancing, and provision of accessible and comprehensive information

	Our long-term vision is…	In 2019-21, we are going to deliver…	Benefitting energy consumers now…	… and in the future	Case study
Reliable and secure system operation to deliver energy when consumers need it	**We will transform the operation of the electricity system so that, by 2025, we will be able to operate a carbon free system.**	Uninterrupted, safe and secure system operation.	Robust investment decisions being made, leading to optimum markets, network development, and system operation costs.	By ensuring access to electricity at all times in the decarbonised, decentralised and digitalised world whilst managing down expected increases in balancing costs remains our focus.	
		Addressing operational issues.	By creating awareness of current and future operability challenges, informing short-term investment strategies, and commercial and operational plans resulting in safe and reliable system and lower BSUoS costs than would be otherwise.	By creating awareness of future operability challenges, informing long-term investment strategies, and commercial and operational plans resulting in safe and reliable system in the future and reducing TNUoS by ensuring the most economic options are chosen when planning, developing and investing in the network.	4, 8
	Our selection and utilisation of resources will be transparent and based on driving consumer value – optimising across generation, storage, demand side (be they large scale, distributed or embedded) on an equal basis.	Upgrade of information systems.	By ensuring a safe and reliable system now and in the future as it rapidly transforms with low-carbon, intermittent, non-synchronous and distributed generation sources.		3
		Transparency around data used in the ENCC and short-term decision making.			
Smart data driving zero carbon system operation and markets	**We will transform the data we make available – providing a clear interface to all ESO data, including core market and operational information, that can be easily accessed and interrogated with industry standard application programming interfaces for ease of access and use.**	Electricity Operational Forum and stakeholder engagement.	By ensuring the most economic options are chosen when planning, developing and investing in the network and enabling better functioning markets leading to lower costs. (2)	By robust investment decisions being made by network operators and market participants, and supporting the low carbon transition resulting in new providers and technologies entering and compete in the existing and new markets.	2
		Insights documents.			
		Forecasting.			
		Operational insights.			
		Information access: data portal.			

Through our case studies in appendix C, we estimate we will deliver the following value for consumers

KEY
- 2 Case Study 2: Improving BSUoS forecasting
- 3 Case Study 3: ENCC and short-term operational decision making
- 4 Case Study 4: Future operability challenges
- 8 Case Study 8: Changing Embedded Generator Protection Systems

Exceeding baseline expectations

Under role 1, over the next two years we will take actions that go beyond those expected of an efficient and competent system operator to unlock additional consumer benefits:

- ***Greater transparency of close-to-real-time decision making and data used by the ENCC;*** our vision is to provide greater transparency of our selection and utilisation of resources. We will drive consumer benefit as we optimise across generation, storage, demand side on an equal basis. We are striving to be transparent in the costs we incur as the residual balancer. In doing this, our aim is to make this as user friendly as possible. We will develop new business processes and innovative tools to allow us to share this with stakeholders on an ongoing basis.
- ***Addressing operational issues, specifically the roll out of Loss of Mains protection settings, and providing greater understanding of balancing decisions and constraints information through operational insights;*** our vision is to transform the operation of the electricity system so that, by 2025, we will be able to operate a carbon free electricity system. The Great Britain energy market is decarbonising, digitising and decentralising faster than elsewhere. Our *Operability Strategy Report* is identifying the challenges further into the future than ever before. We are using our unique perspective to engage and support industry in acting to enable the development of smarter, more complete solutions across assets and markets to deliver an operable system.
- ***Information access through the development of an open data portal;*** our vision is to transform the data we make available. We will provide a clear interface to all ESO data, including core market and operational information, that can be easily accessed and interrogated. This year we will trial new approaches to how we share information engaging with our stakeholders to understand how we can best share information and adopt innovative approaches to deliver most benefits for consumers. Initially we will develop our website to make the information more easily accessible. We will provide an investor timeline showing how our data fits together across different timescales, categorise the information against themes for example balancing costs or ancillary services, and provide an easy way for stakeholders to find the information they need. These activities will inform and shape our ultimate vision of implementing a data portal.
- ***Delivery and implementation of an Energy Forecasting Strategy Roadmap;*** we are working in strategic areas to improve accuracy and accessibility of our forecasts. We will set out our vision for transforming energy forecasting in our *Energy Forecasting Strategy Roadmap*. This is a transformational project aimed at delivering advanced energy forecasting capabilities for the Great Britain market by employing techniques such as machine learning, deep learning, advanced statistical models, and more.

Activities and deliverables 2019-21

Operating the system	Information provision and transparency
• Uninterrupted, safe, secure system operation; • Transparency of data used in ENCC and close-to-real-time decision making; • Addressing operational issues; • Balancing cost management; • Upgrade of information systems.	• Insight documents; • Electricity Operational Forum and stakeholder engagement; • Operational insights; • Forecasting; • Information access.

Uninterrupted, safe, secure system operation

We operate the system in real time and run systems and processes to ensure secure, economic and efficient dispatch of the system.

At real time, we focus on the secure, efficient and transparent operation of the power system. To do this, we must consider the safe and secure operation of the network alongside the balancing of energy supplies across that network. Our work starts several years ahead of time. In those timescales, detailed work tends to be either network focused or energy balance focused, with regular tie-in points to ensure both are coming together.

From a network perspective, the *NOA* process considers future requirements of the network including options to deliver them and the impact on the system of the option implementation. Where work is required, we explore how to implement solutions.

Alongside this we must build a plan of outages incorporating transmission network assets; generators, distribution network and transmission network. This is to allow system users to build new assets and maintain existing ones. To do this, we secure the network against the expected range of generation and demand backgrounds. These outages are placed in a plan considering the information available to us. Closer to real time we explore additional optimisation of outage placement, assessing the balancing costs associated with each and looking at how best to manage those costs. This may be via trades, via contracts or leaving it to the Balancing Mechanism (BM) where there are a number of generation actions which could resolve the issue.

Turning to energy balancing, our Operability Strategy pulls from the work in the *Future Energy Scenarios (FES)* and the NOA to ensure we have the tools to operate the power system. Stakeholder feedback at these stages, informs the work to reform and procure the services we need.

We continue to tune our requirements, for both operating the power system and balancing of energy, from several years out down to near real time. We identify critical outages on the system, which could limit our ability to access a particular set of services, or perhaps would change the largest loss on the system. Regular and disciplined check points ensure that we understand the challenges of securing the power system, the tools required and available and have plans in place for the most efficient management of the system, looking season and year ahead. Approaching real time, these plans become more granular.

Within month, the network and energy streams of work are brought closer together so that the ENCC can operate to a single, secure, efficient and optimised plan.

Deliverable	Description	Delivery Date
System security metrics	We will publish metrics that demonstrate our compliance with the security and quality of supply standards.	Q1, Q2, Q3, Q4 2019-2020
Procurement Guidelines Process	Engage with stakeholders on potential changes	Q3 – Q4 2019-20
	Publish consultation document	Q4 2019-20
	Issue final document to Ofgem	Q4 2019-20
	Sign off by Ofgem	Q4 2019-20

Transparency of data used by our ENCC in our close-to-real-time decision making

Consumer benefit outcomes

Please see case study 1, 3 & 4 in appendix C.

Our stakeholders have told us that they could operate more effectively in their provision of services to us if they had a better understanding of our balancing services requirements close to dispatch timescales, and had access to data upon which the ENCC bases its decisions. Therefore, with stakeholders, we are looking at the data we can share publicly without prejudicing the market and commercial confidentiality. As part of this, we look to publish more explicit requirements. These requirements should stimulate the market to provide the solution and reduce our use of commercial trading and contracting tools. This work should lead to more effective targeted products and solutions, enhancing competition and driving down costs.

Deliverable	Description	Delivery Date
Publication of operational planning data	Currently, we receive data from Balancing Mechanism providers which are used by the ENCC to make decisions. We will engage with stakeholders to find out what data is valuable to them and how we could best provide this. Alongside this we will share complementary analysis and insight of how we make decisions based on this data and we will support stakeholders in understanding this data using webinars. Where we are unable to publish information, we will clearly articulate our reasons.	Engagement with stakeholders commences in Q3 2019-20
Future of the ENCC	As part of our wider transparency, education and operability work, we will continue with our work on the *Future of the ENCC* to outline and inform on the operational challenges we manage.	Publish 5 operational challenges: Q1 2019-20

Operational Insights

Acting on stakeholder feedback, we are planning to make available new information, for example regarding transmission capacity limitations and congestion. This will enable more efficient and effective outage planning and system access co-ordination between us and network operators. This in turn supports providers in offering services to the ESO and reducing the cost of balancing than would otherwise be the case.

Consumer benefit outcomes

Please see case study 1, 3 & 4 in appendix C.

Deliverable	Description	Delivery Date
Insight on balancing decisions taken	Sharing our insight on balancing actions and producing a map of outturn system costs for voltage constraints per region.	Q3 2019-20
	Sharing our insight on balancing actions and producing a map of outturn system costs for thermal constraint costs by region or constraint boundary.	Q2 2019-20
	Improvements to the Daily Balancing Costs report and Monthly Balancing Services Summary (MBSS). This will include more detail on voltage, constraint and mandatory frequency response.	Q3 2019-20
Insight on constraint boundaries	Publish day ahead information on constraint boundaries to share the limit and the expected flow at day ahead.	Q2 2019-20

Electricity Operational Forum and stakeholder engagement

We will engage with industry through high-visibility events, such as the Electricity Operational Forum, providing market participants with the opportunity to interact with us face-to-face. We hope this will enable the industry to gain better understanding and insight into what we are doing and why whilst enhancing their competitive positions with other providers. Our proposed demonstrations to stakeholders of how we dispatch balancing services will also allow this rich interaction between us and market participants. This improved engagement should aid understanding, leading to more technically superior and cost-effective products, and more efficient transactions.

Consumer benefit outcomes

Deliverable	Description	Delivery Date
Electricity Operational Forum	This stakeholder event takes place three times a year to provide operational information.	Q2, Q3 and Q4 2019-20 and 2020-21.
ENCC visit days	Bi-monthly open door to market participants to the ENCC to learn about system operation.	Q1, Q2, Q3, Q4 2019-20 and 2020-21

Addressing operational issues

In parallel with managing on-going operability challenges through commercial mechanisms (for example protecting the system from Rate of Change of Frequency (RoCoF) events), we will pursue technical and engineering solutions to address these issues. For example, we will address a root cause of the RoCoF issue by managing changes to affected Distributed Energy Resources (DER) protection systems, which should reduce the magnitude of the problem, and result in us spending less on commercial actions to manage it.

Consumer benefit outcomes

Please see case studies 4 and 8 in appendix C.

Deliverable	Description	Delivery Date
Roll out of Loss of Mains protection settings	Publish a methodology for how we intend to procure balancing services from Distribution Network Owners (DNOs) to enable RoCoF and vector shift changes.	Q1 2019-20
	Run four tender rounds throughout 2019-20.	2019-20
	Review methodology.	Q4 2019-20

Upgrade of information systems

We continue to work with all our stakeholders to ensure the design and capability of our information systems and IT can cope with the changing needs and demands placed upon it. The pipeline includes upgrades to the Energy Forecasting System (EFS), development of the Ancillary Services Dispatch Platform (ASDP), and changes to systems to comply with the latest European Network codes. These changes will ensure we can operate the system efficiently and effectively.

Consumer benefit outcomes

Deliverable	Description	Delivery Date
ASDP	Moving dispatch of Short-term Operating Reserve (STOR) to ASDP.	Q2 2019-20
Significant upgrading of IT systems to prepare for European Network Codes	Significant upgrading of IT systems to prepare for European Network Codes.	Q3 2019-20
Frequency and time equipment FATE-3	Improvements to Frequency monitoring tool.	Q4 2019-20
Pi gateway refresh	Upgrading of systems to transfer data from Scottish TOs.	Q4 2019-20
EFS	Deliver strategic forecasting solution.	Q3 2020-21
Power Available	Changes to systems required to display power available signal as covered in Role 2.	Q3 2019-20 Q4 2019-20 Q3 2020-21

Deliverable	Description	Delivery Date
Control capability development	Develop new cross industry process for delivering control capability during RIIO-2, including, IT System development.	Q4 2020-21
Interconnector programmes	Continued integration of interconnectors into operational systems.	Ongoing

Insights documents

Sitting at the heart of Great Britain's electricity system, we are able to share our unique view on system operation and our insight into markets, providing analysis across the short and long-term energy landscape through our insight publications. During the year, we publish the *FES, Summer and Winter Outlook* reports and engage with stakeholders through workshops and events to share our insights. This helps market participants make better informed decisions around their participation in the market and investment strategies, ultimately creating better functioning markets.

Consumer benefit outcomes

Please see case study 4 in appendix C.

Our forward-looking *Operability Strategy Reports* and studies of potential scenarios of future system operation allow us to identify challenges ahead of time. We present our findings and insights to industry, proactively working together to develop optimum technical and commercial solutions. This provides us sufficient time to assess different options to deliver the best outcome for the consumer.

Deliverable	Description	Delivery Date
Summer Outlook	Provides our view of the gas and electricity systems for the upcoming summer.	Summer Outlook: Q1 2019-20 & 2020-21
FES	Provides our range of credible scenarios for the future of energy to support the planning the Great Britain transmission system.	FES Publication: Q2 2019-20 & 2020-21
		FES conference Q2 2019-20 & 2020-21
		FES call for evidence: Q2 2019-20 & 2020-21
		FES workshops Q3 2019-20 & 2020-21
	Provides our insights on security of supply for the upcoming winter for gas and electricity.	Winter Review and Consultation

Deliverable	Description	Delivery Date
Winter Outlook and Winter Review and consultation		Q1 2019-20 & 2020-21 Winter Outlook: Q3 2019-20 & 2020-21
Operability Strategy Report	Provide a view of current and future operability challenges, to help inform stakeholders' investment strategies, and commercial and operational plans.	Q1 and Q3 2019-20 & 2020-21

Forecasting

Consumer benefit outcome

Our continued focus on the timeliness, relevance, and accuracy of demand, wind generation and solar generation forecasts benefits the consumer in different ways. It contributes to the short-term decision making of market participants through operational and pricing decisions delivering better functioning markets. Better forecasts with less uncertainty also benefits our ENCC, as less uncertainty means less contingency and lower spend on those products. Our carbon intensity forecasts are enabling the end-consumer to directly make decisions about their energy consumption based on the generation mix predicted to dispatch in short term.

We will deliver an *Energy Forecasting Strategy Roadmap* describing how we will explore and employ innovative technologies such as machine and deep learning techniques to improve the accuracy of our key forecasts. We will increase the frequency of our forecasts to support electricity market participants to make efficient system balancing decisions ahead of real time.

Deliverable	Description	Delivery Date
Publish Forecasting Strategy Project Roadmap	High level plan of the new forecasting strategy project deliverables.	Q1 2019-20
Publish half-hourly photovoltaic (PV) forecasts to market, 24 times a day	Increase the number of published PV forecasts from 2 to 24 times every day (an update every hour).	Q1 2019-20
Publish four additional wind forecasts to the market	Increase the number of published wind forecasts from 4 to 8 per day.	Q2 2019-20
Publish an additional Day-Ahead demand update at 12:00pm every day	Provide an additional day ahead demand update at 12:00pm every day following the 9:15pm daily update.	Q2 2019-20
Make energy forecasts more accessible via a dedicated website and Applications Programming Interfaces (APIs)	Rationalise channels used for sharing energy forecasts and give definitions of data published.	Q3 2019-20

Information access

We will reduce the effort needed to access our information by developing a user-friendly self-service information portal, sharing the information stakeholders want on-demand. This can increase the efficiency of processes and decision making taken by our stakeholders. Increased efficiency in the decision making and transactions between parties in the electricity market should ultimately benefit consumers through cost control and reduction.

Consumer benefit outcomes

Please see case study 1 in appendix C.

We have reviewed different approaches to making data open, and have spoken with experts and stakeholders from our industry and others to understand the merits of each model. Our proposed direction draws inspiration from the model of open data employed by Transport for London (TfL), where data is shared publicly wherever possible for third party users to access and analyse for their own purposes. While explanatory notes are generally needed to accompany data sets, data will otherwise have minimal additional processing applied to it, or its underlying systems, so that we can make the data available as soon as possible. We believe that our own data should be shared first; if there is significant consumer benefit to be realised from investing in enhanced data quality or granularity this will be communicated through engagement with the community of data users.

This approach aligns with, and is informed by, our engagement to date with the BEIS Energy Data Task Force, where we have identified quick wins and long-term activities to deliver most consumer benefit. Examples of quick wins are as enabling third party process automation by sharing data in a machine-readable format where relevant. In the longer-term we will enable unforeseen innovation by providing large volumes of raw data for third parties to analyse and combine for novel solutions).

Our ambition is to pursue this programme of open data provision in an agile and iterative manner. We will work with stakeholders and data users to understand their data needs and then share our data giving priority to those data sets which can provide greatest consumer benefit. Progress during the Forward Plan 2019-21 will be limited but this work is part of a longer-term plan for which additional funding will be required for our RIIO2 period. Our approach will be to make the most beneficial data open as quickly as possible through a relatively light touch data portal, utilising comparatively low levels of investment in Application Programming Interfaces (APIs) or similar solutions.

Deliverable	Description	Delivery Date
Open Data	Through 2019-20 we will work on our longer-term strategy for information access outlined in the in the section above. Part of the strategy is to deliver an interim data portal in 2019-20. This will provide an avenue for our data and reporting, accessible all in one location and in a consistent format. We also plan to deliver an investor timeline on the data explorer section of the website, that allows customers to navigate the forecast and outturn reporting that we publish at different timescales.	Data explorer page on website: Q1 2019-20 New data portal: Q3 2019-20

How we will measure our performance in 2019-20

Metric 1 – Balancing cost management

We consider that this performance metric is in effect providing a near time measure of the outcomes of our actions across all of the three role area for example:

- Delivering of *Product Roadmaps*
- Forecasting
- Addressing operational issues

Consumer benefit outcomes

Please see case studies in appendix C.

The Great Britain energy market has undergone dramatic changes over the past decade as the move to decarbonise electricity has accelerated under a number of initiatives. This has driven considerable changes in both solar and wind generation as well as real world results from energy efficiency. This combined with the development of decentralised energy sources, higher interconnection to Europe and more activity in the market has resulted in a very different energy landscape when compared with 10 years ago. Alongside this, industry focus on commercial solutions ahead of build decisions through the *NOA* have also led costs moving from asset investment to operational management.

These changes have driven a significant amount of benefit for the Great Britain consumer and United Kingdom as a whole. They have also introduced a number of challenges in operating the transmission system. As demand for electricity have fallen and the sources of energy have changed, the physical requirements to operate the network have not changed. As highlighted in our *Operability Strategy Report*[4]these challenges are ever increasing as we continue the transition to a low-carbon energy landscape. In managing these challenges, we have used insights and markets to drive benefit to the consumer in delivering an operable system. However, the cost of operating the system will increase as more intervention is required to manage the five operability challenges. Role 1 and metric 1 set out our expectations of continuing to develop and evolve operational and market strategies to ensure an operable system whilst focusing on reducing the costs to the consumer.

Consumer benefit

We will continue to use this metric to highlight our performance on controlling balancing cost spend and the size of the BSUoS levy. The continuing decarbonisation and decentralisation of generation combined with changes in how energy is being consumed would have, without intervention, caused a significant increase in balancing cost spend. We have and continue to be focused across the organisation on finding and delivering both step-change and incremental improvements in what we do to deliver savings for the consumer through controlling, reducing and optimising this cost.

Context

We will continue our focus on system balancing and security for an optimum cost in line with the expectations that Government, the regulator and consumers have of us. The on-demand provision of electricity is a fundamental part of our modern life but must be continuously attended to with the utmost importance by the ENCC and supporting functions.

[4] https://www.nationalgrideso.com/document/134161/download

Metric

The methodology is unchanged from that agreed with Ofgem for 2018-19, please refer to pages 10 – 12 of the Forward Plan Performance Metric Definition 2018-19 for the methodology[5].

The metric compares our current balancing spend against historic trend following adjustments for significant cost drivers. The benchmark only includes cost drivers that were identified at the beginning of the year; a benchmark for expected balancing costs will be derived from the application of a linear trend through five year moving averages of historic balancing cost (excluding Black Start), beginning with the rolling mean for 2009-2013 to 2013-17 as per Table 1 – Balancing cost 2009-17

Table 1 – Balancing cost 2009-17

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017
Total balancing spend (£m)	662.3	540.5	796.5	786	851.1	824.8	849.2	873	940

We intend to use historical data to develop a baseline of costs. By applying a historical dataset that intrinsically reflects a broad range of operational situations we can capture a sufficient number of observations that the System Operator has encountered to establish a baseline for costs. The historical data produces a benchmark for 2019-20 of £1019m.

In 2018-19, there have been a number of unforeseen step changes in costs that were not present in the historical rolling average, or the forward-looking cost adjusters. In recognition that there are a number of foreseeable fundamental drivers that might impact balancing costs but which historical costs might not reflect, we will also include additional adjustments. The adjustments for these foreseeable fundamental drivers this year are:

1. HVDC availability

Availability of the Western HVDC Link will continue to have a downward impact on the rolling average, reducing the constraint spend we would anticipate for managing flows from Scotland into England. We forecast a reduction in balancing spend of £135m.

2. South East reinforcement work

We anticipate higher costs in operating the system caused by the unavailability of transmission assets in the South East of the network. This will be for 12 weeks and is to deliver reinforcements recommended by the NOA process. These reinforcements are required to provide increased capability on the network and optimise costs across TNUoS and BSUoS for the anticipated increased power flows driven by more interconnection.

As a result of this reinforcement we see a reduction of constraint costs of between £1.4bn and £3.7b over the total lifetime of this project. Taking the middle of this range gives a saving of ~£60m a year for 40 years. It's challenging to say specifically when these savings will occur, however our initial thoughts suggest they would occur mainly between 2020 – 2030 as that is when Great Britain is a net importer.

We forecast an increased balancing spend of £60m-80m to manage transmission network flows during this work.

3. RoCoF and Vector Shift

A programme of work is planned to start in 2019-20 to change the settings of existing RoCoF relays and replace Vector Shift relays. A recent modification to the Distribution Code requires all generators to have completed this work by 2022 to be compliant. With balancing costs rising year on year with the increasing levels of asynchronous generation, there would have been a system

[5] https://www.nationalgrideso.com/sites/eso/files/documents/Performance%20Metrics%20Definition.pdf

risk driven by these relay settings. So, to mitigate this, we have been proactive in working with all the DNOs to agree an accelerated change programme to curtail these costs earlier.

If no action is taken, we forecast a steady increase in balancing spend on Loss of Mains risks. This will continue as the contribution of traditional synchronous generation to meeting electricity demand decreases and larger infeed loss risks connect. Our latest forecast of costs is shown in the 'do-nothing' line below. Please note that there is some additional uncertainty in this forecast which will remain until we fully understand the market characteristics we observed during this financial year.

We have developed a plan to address Loss of Mains risks working on a whole system basis with the Distribution Network Owners. The main driver of activity in the plan is an offer of payment to distributed generators in return for making and certifying they have made the necessary changes. This lies alongside a mandated requirement to make the change by March 2022. The plan will increase balancing costs in the short term. However, we have designed a process which will encourage early changes to loss of mains protection settings which will reduce operational costs in the long-term. This process is designed to ensure that the change is successful. The plan is built around a quarterly cycle of performance reporting, review and ultimately a decision to stop if the value of continuing is less than the benefit. Experience of previous similar changes suggest that relying on the mandated requirement alone is likely to result in either significant overruns or at worst failure to deliver. The forecast costs shown in the table below will be updated on a quarterly basis in line with plan performance and the latest information available.

£m		19-20	20-21	21-22	22-23	23-24	24-25
Do Nothing	Forecast Balancing Costs	130	150	150	170	190	290
	Cumulative	130	280	430	600	790	1080
Implement Change Programme	Forecast Balancing Costs	130	150	40			
	Forecast Change Costs	20	30	10			
	Total Balancing Costs	150	180	50			
	Cumulative	150	330	380			

Table 2 – RoCoF forecast costs and benefit

4. Other drivers

During 2018-19 we have incurred additional costs in maintaining a safe and secure system. We have identified that the following further cost risks may continue into next year which may form part of further adjustments as they become clearer

- Scottish security during 2018-19: we have incurred significant unforeseeable additional cost due to generator outages in Scotland. We have needed to arrange contracts with different generators and take significant actions in the balancing mechanism to maintain system security. We currently anticipate that these generators will return from outage in 2019-20.
- The Capacity Market was suspended during 2018-19. This could lead to generators increasing their prices in the balancing market during periods where margins are short, in turn leading to an increase in balancing costs in 2019-20.

Performance benchmarks

Five year rolling average	Savings from HVDC	South East reinforcement increase	RoCoF increase in cost	Benchmark 2019-20
£1019m	(£135m)	£60m-80m	£110m	£1054m-£1074m

Metric 2 – Information provision scorecard

This performance metric is measuring the outcomes of the following deliverables:

- Forecasting
- Operational insights

We publish data and information to the market on a regular basis; some required by our licence or code obligations and others as our commitments to the market. We will use a baseline scorecard to summarise the information provision per quarter to show that we are continuing to provide the information needed by the market. This metric is seeking to demonstrate on-time-in-full information publication performance in relation to our activity to overcome our first & second barriers (range of information; frequency & accuracy of information); a number of these commitments are required by our licence. This metric covers the following information provision:

Consumer benefit outcomes

Please see case study 2 in appendix C.

Information provision	Frequency of provision	Deadline and targets
Monthly balancing services summary (MBSS)	Monthly	Each monthly report published by the end of the following month.
Daily cost summaries	Daily	85%* of reports produced within 2 working days.
Trades	Daily	97%* of trades published within 1 hour.
BSUoS reports	Monthly	Monthly BSUoS report published by the 10th working day.
Market information report	Monthly	Monthly report produced on time (as per schedule) and right first time 100% of the time for FFR, FR and STOR.
Daily BSUoS forecast	Daily	100%* of forecasts published by 8.00 at day ahead for Tuesday-Saturday and 17.00 on Friday for Sunday-Monday.
Demand forecasts	Daily	100%* of forecasts published on time. Forecasts published every day no later than 9:15am.
Wind forecasts	Daily	100%* of forecasts published on time. Forecasts published every day no later than 9:15am.

* We will publish these forecasts and summaries according to this schedule except in exceptional circumstances outside of our control including IT system outages and extreme weather conditions.

Metric 3 – Energy forecasting accuracy metric

This performance metric is measuring the outcomes of the following deliverables:

- Forecasting

Consumer benefit

We are working in strategic areas to improve our energy forecasting accuracy. This will support market participants to manage their generation and consumption ahead of real time and therefore reducing the number of actions that we need to take to balance the system. This will result in less consumer money spent to balance the electricity network.

Consumer benefit outcomes

Please see case study 5 in appendix C.

Context

Our aim is to constantly improve energy forecasting accuracy, increase the frequency of key forecasts, and publish available data and information to industry. Accurate day ahead demand forecasts and day ahead Balancing Mechanism Unit (BMU) wind generation forecasts are essential to support the market to balance its position ahead of real time. Day ahead forecasts are very important because this is where market liquidity is greatest. A good and potentially more frequent day ahead forecast allows parties to efficiently trade their residual positions before within-day. Therefore, during 2019-20, we will continue to drive and track forecasting accuracy with the forecasting metrics proposed below for the two key forecasts:

- Day ahead national demand forecast,
- Day ahead BMU wind forecast.

Metric

To measure our performance, we will use the monthly forecasting accuracy of our day ahead demand forecast and day ahead BMU wind forecast.

Day ahead demand forecast accuracy

The day ahead demand forecast accuracy is defined as the Mean Absolute Error (MAE; MW) calculated for each cardinal point and is based on:

- Operational national outturns in MW;
- National demand forecast in MW.

For more information on cardinal points, please see our website[6].

The accuracy of this is calculated monthly to provide a Monthly Mean Absolute Error (MMAE, MW), and is calculated as follows:

$$MMAE\ (MW) = \frac{\sum_{CP}^{Month} |Forecast\ (MW) - Operational\ Metering\ (MW)|_{CP}}{Total\ numer\ of\ CPs\ of\ the\ month}$$

The methodology for this metric considers every single forecasting error for all cardinal points in the month. In this way, the size of large errors will have an impact on the monthly performance calculations.

Evening peak performance over the Triad period (period from November to February when Triad charges are incurred by market participants) will be based on the Triad avoidance calculation methodology described and shared on our website[7].

The target for each month is the average monthly mean absolute error (MW) over the past three financial years: 2016-17, 2017-18, 2018-19. At the time of writing not all the outturn data is available for the financial year 2018-19. So, those targets affected are marked as provisional in the table below and will be revised when the data is available. By following this methodology, the day

[6] https://demandforecast.nationalgrid.com/efs_demand_forecast/faces/DataExplorer#!1
[7] https://demandforecast.nationalgrid.com/efs_demand_forecast/faces/DataExplorer

ahead demand targets are set out in *Table 3 day ahead demand forecast targets for financial year 2019-20:*

Table 3 day ahead demand forecast targets for financial year 2019-20

Month	Target (MW)	Month	Target (MW)
April	709.9	**October**	620.7
May	598.3	**November**	600.7
June	524.4	**December**	690.9
July	542.1	**January** *	645.5
August	569.7	**February** *	667.7
September	577.4	**March** *	719.4

** Provisional target to be updated when final outturn data is available.*

Every month, the resulting MMAE is compared to the respective monthly target to identify whether we have achieved our target for the month. This will result in one of the following two outcomes:

- **Target missed:** MMAE (MW) > Average Monthly Mean Absolute Error (MW);
- **Target met:** MMAE (MW) <= Average Monthly Mean Absolute Error (MW).

Day ahead BMU wind generation forecast accuracy

The accuracy of the day ahead wind forecast is calculated using absolute percentage error (APE; %) calculated for each settlement period, and is based on:

- First run settlement metering data (in MW);
- Half hour BMU wind forecasts (in MW) excluding times where the wind farm received an instruction to reduce output from the ENCC: Bid Offer Acceptances (BOA);
- Total Wind BMU Operational Capacity. This is the total BMU wind capacity operating at national level.

The 2019-20 wind metric calculations will not include secondary BMU wind farms joining under Wider Access.

The accuracy is calculated monthly to provide a monthly mean absolute percentage error (MMAPE; %) using the following equation:

$$MMAPE\ (\%) = \frac{\sum_{HH}^{Month}\left[\frac{|Forecast\ (MW; excluding\ BOAs) - Settlement\ metering\ data\ (MW)|}{Total\ Operational\ Capacity}\right]_{HH}}{Total\ numer\ of\ HHs\ of\ the\ month}$$

The methodology for this metric considers forecasting errors for every half hour during the month. In this way, the size of all errors will be included in the monthly performance calculations.

The target is the average monthly mean absolute percentage error (%) calculated by considering the past three financial years: 2016-17, 2017-18, 2018-19. At the time of writing not all the outturn data is available for the financial year 2018-19. So, those targets affected are marked as provisional in the table below and will be revised when the data is available. By following this methodology, the day ahead demand targets are set out in *Table 4 BMU wind generation forecast targets for financial year 2019-20.*

Table 4 BMU wind generation forecast targets for financial year 2019-20

Month	Target (%)	Month	Target (%)
April	5.25	**October**	4.62
May	4.47	**November**	5.32
June	3.92	**December**	4.44
July	4.52	**January ***	5.39
August	4.21	**February ***	5.26
September	4.57	**March ***	6.06

** Provisional target to be updated when final outturn data is available.*

Every month, the resulting MMAPE is compared to the predefined seasonal target to identify whether we have achieved our target for the month. This will result in one of the following two outcomes:

- **Target missed:** MMAPE (%) > average seasonal mean absolute percentage error (2018/19, 2018/17, 2017/16) (%);
- **Target met:** MMAPE (%) <= average seasonal mean absolute percentage error (2018/19, 2018/17, 2017/16) (%).

Performance benchmarks

For each month, we can either have met or missed our target for each of these metrics. At the end of the year, we will count how many months we have met our targets and apply the benchmarks:

- Below benchmark: 0-5 months;
- In line with benchmark: 6-8 months;
- Exceeds benchmark: 9-12 months.

These criteria have been based on examining historic data and the effort required to perform better than the target for more than 6 months of the year. Therefore, the forecasting performance would be considered in line with the benchmark if the target accuracy is achieved for 6 months of the year or more.

Managing and forecasting the electricity system is becoming more and more difficult. This is mainly due to the growth of generation connected to the distribution network that is not visible to us, change in customers' behaviours and additional penetration of technologies such as batteries and smart meters. For this reason, we believe that, to achieve an annual performance in line with expectations, the metric should deliver at least six months with improved forecasting accuracy compared to the same months over the last three financial years.

By considering the last three years in setting the target accuracy benchmarks, we are smoothing out the effect of unseasonable extreme weather which we consider an externality to our error as it is not under our direct control. A month which has unusual weather would mean that the accuracy of forecasts would be lower due to the unpredictability of the weather. This forecasting metric is designed to take account of the occasional occurrence of extreme weather by calculating the targets using the past three years of historical data.

2. Facilitating competitive markets

Role 2
Facilitating Competitive Markets

Ensure the rules and processes for procuring balancing services, maximise competition where possible and are simple, fair and transparent	Promote competition in wholesale and capacity markets

Long-term vision

Appropriate markets are essential to operate a carbon free system. We will operate this carbon free system and deliver economic security of supply with much higher volumes of low-carbon generation and a significant increase of flexible sources of energy such as demand-side response and storage. We have a vital role in delivering this complex task through development of the balancing service markets and promoting competition in wholesale and capacity markets.

Build the future ancillary service and wholesale markets

By 2023, all market participants 1 MW and above will have equal access to all our ancillary service markets and the Balancing Mechanism through a single integrated ESO markets platform. They will know that they are treated fairly, both in the purchase of services and in the way they are dispatched, as we are transparent in all that we do. We will continue to work actively to reduce the minimum size of market participants as we transform our ENCC systems and processes.

As new markets develop, for example at a distribution or community level, it is essential that participants can stack value by participating across these markets, regardless of who owns or operates them. This principle will be core to both how we design our markets and also an integrated market platform, which will expand to allow participants to access the full range of markets in a co-ordinated way.

By 2023, the wholesale electricity market will have hundreds of participants. There will be a liquid day-ahead auction which provides a strong reference price for short-term power. This increased market liquidity will drive increased wholesale market efficiency.

Transform access to the Capacity Market

By 2025, we will be trusted to deliver security of supply against a clear standard agreed with the Government. We will be responsible for all elements of the auction; advising the Government on the volume to purchase, managing the rules change process, running the auction and managing the contracts. By transforming how we facilitate these activities, security of supply will be delivered with a plant mix that supports the UK's 2050 carbon reduction target at the lowest possible cost to consumers. All technologies will be able to participate in the Capacity Market in an equitable manner and participants will feel that they are fairly rewarded for their contribution to security of supply.

Develop codes and charging arrangements that are fit for the future

We want our codes to facilitate the rapid change required to deliver the UK's 2050 carbon reduction target. By 2025, our codes and code governance will no longer be perceived as a barrier to change. Code modification will work for hundreds of market participants, rather than the tens of participants for which the current process was devised.

We have discussed with stakeholders the possibility of aligning commercial, technical and regulatory arrangements across transmission and distribution. There was a call from stakeholders to simplify and unify governance, while driving alignment across transmission and distribution and pulling it all together under one governance structure.

Delivering consumer benefit

The benefits for consumers if we as an industry are successful are high. The electricity balancing, capacity, and wholesale markets have huge value. The value of traded electricity is worth over £35 billion per year[8]; a 1 per cent increase in efficiency across these markets would deliver £350 million of benefits to consumers. More importantly, a report for the Committee on Climate Change[9] has indicated that system costs to consumers could increase by £3 billion to £5 billion per annum by 2030, and by almost £8 billion per annum by 2050, unless significant new sources of flexibility are attracted onto the system.

In developing a vision for markets, it is important that they all work together so that participants can make efficient business decisions. This is central to all our work.

Our work on Balancing Service markets is undertaken with these future savings for consumers in mind. The focus is on understanding and removing barriers to entry in our markets to attract new sources of flexibility. This increases competition in the short-term which delivers consumer benefit in the form of lower bills today but more importantly it creates the pipeline of new flexibility sources needed to balance the system in the future and deliver the £3 billion to £5 billion per annum savings by 2030. There are a number of factors driving these savings cited in the report:

- **Reduced curtailment of low-carbon generation sources:** system flexibility sources such as energy storage facilities, demand side response (DSR) or interconnectors can absorb/export surplus generation in the system thus avoiding energy curtailment and associated costs.
- **Efficient provision of operating reserve and response facilities:** operating reserve provided by DSR and storage reduces the need to maintain thermal plant at minimum stable generation with the associated impacts on carbon emissions and operating costs due to efficiency losses.
- **Potential savings in generation capacity:** less curtailment of low-carbon plant reduces the capacity of low-carbon plant required to meet the carbon targets. In addition, the peak demand can be reduced through the use of storage and demand side response, reducing the peak capacity required to deliver security of supply.
- **Deferral or avoidance of the network reinforcement/addition:** in addition to the network capacity savings driven by the lower generation capacity requirements described above, additional network capacity savings are possible by deploying flexibility to manage network constraints and reassessing the need for network reinforcement in conjunction with innovative network planning and operational standard.

The reforms to our Balancing Services markets alone will not deliver the required volume of flexibility as the potential earnings from these markets are not sufficient to support the investment case for flexible assets. Instead the assets must be able to stack revenues across a range of markets including the wholesale market, balancing mechanism and capacity market. Our work across these markets are an important enabler, without which, the volume of new flexibility required and therefore the consumer benefits, will not be delivered or will be delivered more slowly. They are also important for delivering reduced environmental damage. Less curtailment of low-carbon generation will be required and there will be less part-load running of thermal plant for response and reserve. This will reduce the carbon emissions in any given year and allow our carbon targets to be reached more rapidly.

[8] Market Value of Traded Electricity for Inland Consumption, page 33 of the Digest of UK Energy Statistics 2018, BEIS https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/736148/DUKES_2018.pdf

[9] https://www.theccc.org.uk/wp-content/uploads/2017/06/Roadmap-for-flexibility-services-to-2030-Poyry-and-Imperial-College-London.pdf

Role 2 Facilitating competitive markets

Delivering our long term vision will create the pipeline of new flexibility sources needed to balance the system in the future.

	Our long-term vision is…	In 2019-21, we are going to deliver…	Benefitting energy consumers now…	… and in the future
Build the future ancillary service and wholesale markets	**By 2023 all market participants 1MW and above will be able to participate directly in our balancing service markets and the Capacity Market.**	Deliver an auction platform for procurement of frequency response.	Opening up the market to more renewable, embedded and demand-side flexibility participants. 6 Up to £6m/ year	Learnings from the trial are used across all products creating wider efficient product procurement and a pipeline of new flexibility sources needed to balance the system in the future and deliver the £3 to £5 billion per annum savings by 2030.
		Fundamentally review and reform our response and reserve products to align with future operability needs and EU standard products.	Reducing barriers to market entry for non-traditional providers creating more competitive markets.	Creating efficient product procurement and usage of products increasing market participation and reduced carbon emissions.
		Enable wider access to Balancing Mechanism.	Reduced ESO spend due to more competitive markets and access to non-BM providers.	
	A sandbox market environment will sit alongside our established markets to enable co-development of solutions to operability issues such system inertia and stability.	Promote industry development of demand side flexibility via Power Responsive.	More efficient product procurement and usage of products through reducing barriers to market entry for non-traditional providers lowering ESO spend.	
		Increase the transparency of our reactive power procurement.	Increasing the number of regional providers and GB-wide providers of relevant services lowering ESO spend.	
		Develop new approaches to system restoration (also referred to as Black Start capability).	Develop competitive markets where previously none existed enabling low-carbon generation sources and DER lower carbon emissions.	
Transform access to the capacity market	**By 2025 we will be trusted to deliver security of supply against a clear standard agreed with Government. We will be responsible for all elements of the Capacity Market.**	Making Electricity Market Reform easier for participants.	Ensuring there is adequate generation provision to meet demand at the right price	
Develop codes and charging arrangements that are fit for the future	**Transform the process to amend our codes, allowing strategic change to be prioritised and implemented efficiently, while ensuring that it is much simpler and less time consuming than now to make incremental improvements.**	Facilitate code change to enable all network users to understand and contribute to the code change process.	Lower bills through enabling better functioning markets and supporting new entrants which stimulates competition. 7	
		Facilitate electricity network charging reform through Charging Futures.	Removal of barriers to market entry, greater provision of more data and information lowering bills through greater market participation and competitiveness.	
	Create a fully digitalised Grid Code which is principles-based, simple to understand and navigate, and enables the flexibility required to support the energy transition.	Transform industry frameworks to enable decentralised, decarbonised and digitalised energy markets.	Working with industry to ensure codes keep pace with the rapidly changing energy generation and supply landscape so that industry can operate efficiently and effectively.	Transparent, simple and accessible code frameworks lowering bills through enabling better functioning markets and supporting new entrants which stimulates competition.

Through our case studies in appendix C, we estimate we will deliver the following value for consumers

KEY 6 Case Study 6: Frequency response auction platform trial 7 Case Study 7: Facilitating code change

Exceeding baseline expectations

Under role 2, over the next two years we will take actions that go beyond those expected of an efficient and competent system operator to unlock additional consumer benefits:

- Our vision is that by 2023 all market participants 1MW and above will be able to participate directly in our ancillary service markets and the capacity market.
  - ***Product Roadmaps* for Responses and Reserve implementation.** We are redesigning, openly engaging on and implementing new frequency response and reserve products. This will remove barriers to entry and create equitable opportunities for all potential service providers whilst maintaining the safety and stability of the network at all times. The auction trial will require ingenuity in algorithm design if it is to automatically manage the trade-off different products at different times of the day, whilst ensuring that the market is clear and transparent for participants. We will analyse the observed market behaviour and forecasts of what the impact of changes to the auction design would be, which will involve the creation of detailed market models and forecasting tools. This learning will then inform wider reform of industry processes and systems to support our 2023 vision to move procurement closer to real time.
  - ***Product Roadmap* for Restoration implementation.** Black start services are very specific in terms of their location, size, durability and ability to coordinate with other assets in a situation where there is no power or communication. This is a particular issue where those assets are connected at a different voltage level where coordination will need to involve DNOs to consider more localised constraints, as well as assets that rely on any form of decentralised control. We are looking to address not only these issues but also how the products might be more competitively procured; we are investigating alternative routes to system restoration, and how disparate assets can be brought together to form a controllable, stable and scalable platform for recovery.
  - **Intermittent Generation.** We need to develop more complex information flows and forecasting for intermittent generation in conjunction with the industry. We also need to ensure that these information flows are accurate and timely for real time decision-making. We will work together with the industry not only to develop the systems and processes, but also to progress the relevant code changes required to implement them in a timely manner.
- We want our codes to facilitate the rapid change required to deliver the UK’s 2050 carbon reduction target. By 2025, our codes and code governance will no longer be perceived as a barrier to change. Our vision is to create a fully digitised Grid Code which is principles-based, simple to understand and navigate, and enables the flexibility required to support the energy transition.
  - **Transform industry frameworks to enable decentralised, decarbonised and digitised energy markets.** We will step up to provide increased leadership and leveraging our experience, stakeholder relationships and our independent view to facilitate and implement framework solutions to achieve our long-term vision.
  - **Enabling all network users to understand and contribute to the code change process.** We are introducing for the first-time new step change services enabling all participants to contribute to code change.
  - **Facilitate electricity network charging reform through Charging Futures.** Charging Futures facilitates network charging reform by increasing industry collaboration and engagement across the whole electricity system. Through our lead secretariat role, we will be stepping up, providing greater thought leadership driving reforms which seek to create a level playing field, recover revenue in a fair manner, and reduce distortions bringing considerable consumer benefit.

Activities and deliverables 2019-21

Ancillary Services Market	Wholesale Markets	Capacity Market
• *Product Roadmap* for Responses and Reserve implementation, • *Product Roadmap for Reactive* implementation, • *Product Roadmap* for Restoration implementation, • Power Responsive, • *Wider Access to BM Roadmap* implementation, • Intermittent generation, • Provider experience.	• Facilitating code change, • Transform industry frameworks to enable decentralised, decarbonised and digitised energy markets, • Facilitate electricity network charging reform through Charging Futures, • Transform the customer experience for network charging.	Over the next two years we will focus making Electricity Market Reform easier for market participants.

Product Roadmaps for Response and Reserve implementation[10]

Consumer benefit outcome

Please see case studies 1 & 6 in appendix C.

We are fundamentally reviewing and reforming our response and reserve products to align with future operability needs and work in conjunction with pan-European Standard Products. We will deliver an auction platform for procurement of frequency response, work we started in 2018-19. These actions will lead to more efficient and competitive markets.

Through our Platform for Ancillary Services (PAS) project, we are delivering a system for non-BM service providers of balancing products to communicate directly with us. ASDP uses web Application Programming Interface (API) data feeds to send metering and availability data to, and receive dispatch instructions from, our ENCC. All these actions will result in lower spend on services than would otherwise have been the case.

Frequency response

Deliverable	Description	Delivery Date
Rollout of full functionality in frequency response auction trial	Second stage of auction trial, introducing dynamic primary & secondary products, linked bids and conversion factors.	Q3 2019-20
Report on development of new frequency response product suite	Update on product development following modelling, analysis and stakeholder feedback.	Q3 2019-20
Report on auction trial	Status update on the success of trial, learnings from the first six months and how these are informing future developments.	Q2 2020-21

[10] https://www.nationalgrideso.com/sites/eso/files/documents/Product%20Roadmap%20for%20Frequency%20Response%20and%20Reserve.pdf

Reserve

Deliverable	Description	Delivery Date
Market design for reformed reserve products	Deliver a proposal for reformed reserve products, including detail of how they will interact with both new frequency response products, spin gen and pan-European Standard products (TERRE/MARI), and a plan for implementation.	H1 2019-20
Report on our plan for retaining specific products	Paper outlining which specific products we are retaining, supported by cost benefit analysis (CBA).	Q1 2019-20
Migration of non-BM Short-Term Operating Reserve (STOR) providers to ASDP	Through the PAS project we move non-BM (typically smaller-scale) STOR providers from historic systems into the new ASPD platform, which will be integrated with ENCC systems.	Q2-4 2019-20
Implementation of pan-European replacement reserve standard products	Support development and implementation of Pan-European standard products (TERRE and MARI) to allow Great Britain parties to participate.	Delivery throughout 2019-21

Product Roadmap for Reactive implementation[11]

We are working to reduce barriers to entry through increasing the transparency of our reactive power procurement and cost of our actions; increasing the numbers of providers in a region (trialling contracts in Scotland, South Wales and Mersey) and across Great Britain; designing more competitive services in conjunction with industry; learning from the Power Potential project how DER can offer reactive services and how that is priced; and working with DNOs on Grid Code change to define efficient reactive power flows between networks.

Consumer benefit outcomes

Please see case study 1 in appendix C.

Deliverable	Description	Delivery Date
Communicate reactive power requirements & historic spend	Per region, to be clear about what we need in short, medium and long-term and confidence levels of requirements, alongside historic voltage costs to increase transparency of spend on voltage actions.	Q2 2019-20
Implement approach for efficient reactive power flows between networks	Having worked with network owners to design a whole system approach to managing reactive power flows between networks, implement that approach.	Q2 2020-21

[11] https://www.nationalgrideso.com/sites/eso/files/documents/National%20Grid%20SO%20Product%20Roadmap%20for%20Reactive%20Power.pdf

Deliverable	Description	Delivery Date
Work with industry to determine future role for reactive power and design more competitive reactive power services	Industry engagement through webinars, consultations and workshops as appropriate to explore options to improve reactive power services and refines these to arrive at an approach that can be implemented.	Q4 2018-19 – Q2 2020-21
Commence implementation plan to enable rollout new approach to competitive reactive power services	Improved reactive power service that promotes competition where possible and enables economic and efficient procurement.	Q3 2020-21
Power Potential trial with UK Power Networks (UKPN)	Innovation project in partnership with UKPN aiming to create a new reactive power market for DER and generate additional capacity on the network.	Q2 – Q4 2019-20
Review learning from Power Potential	Learnings to inform whether to procure reactive power services from DER and if so, how to do so in partnership with DNOs.	Q4 2019-20

Product Roadmap for Restoration implementation[12]

We will develop new approaches to system restoration (also referred to as Black Start capability). We will work with industry to understand how different technologies and providers to those traditionally deployed for this purpose could satisfy the technical requirements. In parallel, we will develop a market approach for the procurement of these services. This work will benefit the consumer as we develop competitive markets where previously none existed, and is also likely to enable low-carbon generation sources and DER to compete.

Consumer benefit outcomes

Please see case study 1 in appendix C.

Deliverable	Description	Delivery Date
Alternative Approaches to Restoration	Undertake a Network Innovation Allowance (NIA) project to understand the capability of 'non-traditional technologies', such as wind, solar, battery storage, EVs, industrial and commercial DSR to contribute to a Black Start.	Q1 2019-20
	Commence our Network Innovation Competition (NIC) project, Black Start from DER to look at the concept of being able to restart the electricity system at the distribution level, rather than the transmission level.	2019-2020
Develop and evolve a market approach for the	We have identified a region where we will trial this approach (South West and Midlands) and will run a tender for restoration services from assets in this area. The Invitation to Tender was published on 4th	Q1 2019-20

[12] https://www.nationalgrideso.com/sites/eso/files/documents/National%20Grid%20SO%20Product%20Roadmap%20for%20Restoration.pdf

procurement of Black Start services	February 2019. Our experience throughout this process will allow us to develop and improve the approach and identify other areas where we could run more competitive procurement of restoration services in due course.	
	A feasibility study process inviting Black Start service providers who have met the minimum technical requirements to proffer commercial proposals. Where possible we will identify other regions where we can run a market mechanism such as the South-East.	Q4 2019-20

Greater Transparency

- We will continue to engage with the industry and provide information on Black Start costs through the MBSS report.
- We will, through our Black Start strategy and Black Start procurement methodology, explain the restoration approach and the procurement strategy in the short, medium and long-term. Where there is an opportunity to amend our restoration approach or create a market mechanism, we shall consult and publish any changes or requirements on the Future of Balancing Services website[13].

Power Responsive

We are promoting industry development of demand side flexibility; identifying and unlocking barriers to entry to maximise opportunities for accessible, competitive markets resulting in lower bills and improved security and reliability of supply.

Consumer benefit outcomes

Please see case study 1 in appendix C.

Deliverable	Description	Delivery Date
Deliver innovation projects to unlock demand flexibility	Work with industry stakeholders through collaborative projects to understand the role of smaller scale assets and technology innovation in unlocking greater flexibility, to identify and unlock barriers to entry and maximise opportunities for accessible, competitive markets	Q1-Q4 2019-20
Power Responsive Stakeholder Engagement	Promote industry developments for demand side flexibility and facilitate feedback to shape ESO deliverables through a range of engagement activities. These will include conferences, working groups, webinars, consultations, editorials, training sessions and reports.	Q1 2019-20 – Q4 2020-21

[13] https://www.nationalgrideso.com/insights/future-balancing-services

Wider Access to Balancing Mechanism Roadmap implementation[14]

We are engaged in a spectrum of activities to enable greater participation in the BM, including: how providers move from non-BM to BM contracts; reducing time and cost of technical connection to the BM; systems for dispatch of aggregated BMUs; work to improve data from aggregators to us, and better settlement data. Wider access to the BM will promote competition and provide the ENCC with greater access to efficiently use the products it needs. This will lower cost to consumers, improving quality of service and contributing towards reducing environmental damage.

Consumer benefit outcomes

Please see case study 1 in appendix C.

Deliverable	Description	Delivery Date
Clearer accession requirements for BM participation and enable aggregated BMU participation in balancing services	Ensure clear and proportionate arrangements for parties to sign up to relevant Great Britain codes and for BM obligations in the provision of BM ancillary services.	Q1 2019-20
Use better technology/systems to improve efficiency of installing communications with BM providers and optimising BMU dispatch	Improved and clearer communications system requirements: • Testing and improvements of IS solutions, to include web-based platforms, • Final IT user specifications available to industry, • Wider access go live.	Delivery throughout 2019-20
Support industry work on providing and delivering against Physical Notifications (ELEXON led) and also support on work on accurate settlement for behind the meter	Provide a mechanism for aggregated BMUs to submit accurate predicated generation profiles (PNs) and provide a way to accurately determine how much energy an aggregated BMU has delivered at their connection point to the distribution system.	Q3 2019-20

Intermittent Generation

Consumer benefit outcomes

Power available is an operational metering signal received from Power Park Modules (e.g. wind) that combines live weather readings with plant capability to provide a dynamic, real-time indication of maximum potential output. We will increase the number of options and market participants available to the ENCC by developing the technical concept of generation power available signals; integrating this signal/data into product definitions, control and settlements systems, and processes. This allows intermittent generation to participate more effectively in ancillary/balancing services, lowering cost to consumers and improving quality of service.

[14] https://www.nationalgrideso.com/sites/eso/files/documents/Wider%20BM%20Access%20Roadmap_FINAL.pdf

Deliverable	Description	Delivery Date
Raise code modification to apply Power Available consistently across technical & commercial codes	Power Available, Maximum Export Limit (MEL) and De-Load need consistent application across technical and commercial codes to facilitate accurate settlement and imbalance reporting.	Q1 2019-20
Publish Power Park Module signal best practice guide	Functional description of best practise for Power Park Modules submitting Power Available to supplement technical codes.	Q2 2019-20
Deliver Power Available integration phase 1	Integration of Power Available into energy calculations to improve ENCC visibility of Power Park Modules returning from BOAs and high-wind shutdown.	Q3 2019-20
Publish wider strategy on flexibility from intermittent generation	Long-term vision and next steps for increasing flexibility from intermittent generation.	Q4 2019-20
Deliver Power Available integration phase 2a	Integrate Power Available into settlement and real-time response calculations to facilitate use of wind units for Mandatory Frequency Response (MFR).	Q4 2019-20
Deliver Power Available integration phase 2b	Improve wind forecasting and response optimisation by blending Power Available with wind forecasts close to real-time.	Q3 2020-21

Provider experience

Consumer benefit outcomes

We are working to offer an efficient experience for providers through development of a self-service approach. This will deliver greater transparency, reduced reliance on account management, online contract management, real-time data visibility, accessible supporting documentation and feedback collection. This focus creates more efficient and effective interactions and transactions between ourselves and providers. This will benefit consumers by helping to ensure we are procuring the right products at the right times in the most competitive and efficient way, controlling the BSUoS costs which are ultimately funded via the consumer bill.

Deliverable	Description	Delivery Date
Feedback approach	A survey framework for getting feedback from our providers at key points in the journey including onboarding, tendering, contracting and query management which will complement current metrics. This is then used to inform process improvements.	Q1 2019-20
Improved online resources	Clear signposting to relevant sources of information on our website; interactive guidance document for each balancing service; and checklist of entry requirements for each service to support providers in understanding their eligibility to participate.	Q1 2019-20

Facilitating code change

We will work with industry to ensure codes keep pace with the rapidly changing energy generation and supply landscape so that the industry can operate efficiently and effectively for the benefit of the consumer. We will help stakeholders access information in a clear and transparent way, to enable informed and value-adding debate.

Consumer benefit outcomes

Please see case study 7 in appendix C.

Get the basics right

We recognise that we still have work to do when delivering against our stakeholders' baseline expectations. During 2019-20, we will continue to remove frustrations from the code change experience.

Deliverable	Description	Delivery Date
Meeting calendar & transparency of workgroups	Targeted website improvements to ensure all meetings are available within our code modification calendar with meeting outcomes available and transparent.	Q1 2019-20
Governance process FAQs, improved guidance material and critical friend review	Plain English and easily digestible documentation that educates the industry on the governance process and increased service provision to modification proposers.	Q2 2019-20
Facilitation of pre-modification discussions	Supporting pre-modification proposals with subject matter expertise and cross code implications being considered to ensure the scope and defect is correctly identified..	Q3 2019-20
Incorporation of all 14 Code Administrator Code of Practice (CACoP) Principles	Adoption of all 14 CACoP principles in a robust manner whilst supporting the development of modifications.	Q3 2019-20

Enabling all network users to understand and contribute to the code change process

There are increasing numbers of parties in the electricity industry with differing information needs and preferences. As a code administrator, we believe that we can do more to keep people informed of how our frameworks are developed, creating opportunities for network users to contribute to their development. This will see a more effective governance process that delivers greater consumer benefit. This involves developing different levels of information, communications and routes to access the information, so stakeholders can choose the level that is right for them; whether it is key strategic insights or a detailed involvement in proposed changes. Developments across 2019-21 will be driven by ongoing engagement with our stakeholders.

Consumer benefit outcomes

Please see case study 7 in appendix C.

Deliverable	Description	Delivery Date
Engage all parties to understand information requirements for code modifications and	Work with stakeholders to understand how they want to be able to better access information on code modifications and implement solutions in a timely manner. For example, the possible	Q1 2019-20

provide executive summaries on modifications	introduction of a monthly newsletter if backed by stakeholder feedback. Introduction of executive summaries on modifications to highlight the essential points.	
Code administrator website	Redevelop our code administration webpages to improve access to information required for industry parties to raise new modifications and understand progress of existing modifications.	Q3 2019-20
Raising potential impact of modifications	Publication of ESO Initial Written Assessments when a modification is first raised to help industry understand the potential impacts of a modification.	Q3 2019-20
Governance surgeries	Introduction of new governance surgeries including webinars and bite size videos to show and guide industry parties through the process.	Q2 2019-20
Historical timelines & horizon scanning: cross-code	Updates to our website to showcase all historical modifications and outcomes across Grid Code, Connection and Use of System Code (CUSC) and System Operator Transmission Owner Code (STC) over last two years. Introduction of a new holistic view of all cross-code changes which impact codes we manage.	Q2 2019-20
Horizon scanning: strategic	Provide a view of all cross-code changes which impact the codes that we manage.	Q2 2019-20
	Consideration of change congestion across the energy industry including a strategic view of legislative and regulatory changes over a three to five-year window. .	Q3 2019-20

Transform industry frameworks to enable decentralised, decarbonised and digitised energy markets

There is need for fundamental code reform, this will improve customer service and lower consumer bills than would otherwise be the case by removing barriers to entry and better facilitating competitive markets. We will ensure that consumer representatives can have a voice in the debates, alongside new and smaller participants, to drive fair outcomes for all. Whilst we have traditionally facilitated discussions when focussing on major reform, through legal separation of the ESO we will step up and provide increased thought leadership. Helping to better inform industry discussions and deliver better outcomes for consumers.

Consumer benefit outcomes

Please see case study 10 in appendix C.

Leadership in the successful transformation of the electricity access and charging regime

We will take a leading role through increased thought leadership, continuing our role as lead secretariat for Charging Futures to facilitate balanced industry-wide debate throughout the consultation periods and the subsequent decision making process. Where appropriate we will support the transformation of charging and access through code modifications. We will focus efforts on:

- **Targeted Charging Review (TCR):** In November 2018, Ofgem published their minded to consultation and draft impact assessment for the TCR and plan to publish a consultation decision/policy statement in June 2019. Relevant code modifications are expected to be raised in Q2 2019-20 to implement this decision/policy statement.
- **Balancing Services Charges Task Force:** Throughout Q1 2019-20, we will continue our leadership of the ESO-led task force, working collaboratively and transparently to provide the final report to Ofgem. This will ensure Ofgem can consider the views of the task force in parallel to wider industry feedback on their TCR minded to consultation. Relevant code modifications related to Balancing Services Charges are expected to be raised in Q2 2019-20 following the publication of the TCR decision/policy statement.
- **Network Access and Forward-Looking Charges Review:** Ofgem launched their Significant Code Review for the Electricity Network Access Project in December 2018 and we will continue to provide collaborative thought leadership within this programme ahead of a decision being made by Ofgem in Autumn 2020. In parallel we will continue to be actively involved in those areas which are outside of the scope of the Significant Code Review, such as the development and delivery of incremental improvements to queue management and interactivity in collaboration with the ENA Open Networks project.

Leadership in the Energy Codes Review

In November 2018, BEIS and Ofgem announced an Energy Codes Review programme intending to deliver a consultation on existing arrangements by Summer 2019. The review will assess whether the existing energy codes are fit-for-purpose and the need for fundamental reform.

Through our engagement with stakeholders and our experience with the existing arrangements, we believe this to be a timely and necessary review. We will be fully involved taking a leadership role leveraging our experience, stakeholder relationships and our independent view with the aim of ensuring that the arrangements work for our customers, wider stakeholders and consumers.

To support and stimulate the debate, we will publish a thought-piece to set out our own views on the potential future arrangements; this will be informed by the insights we have gained from feedback provided by stakeholders related to issues with the energy codes and how they can be improved.

Working for you on European matters

In our 2018-19 Forward Plan, we discussed our role in the continued implementation of the European Network Codes and how we prepare for and influence the Clean Energy Package and EU exit aiming to mitigate risks to both industry and consumers. Over the next two years, we will continue to work for and with our stakeholders on European matters to provide transparency on future change which will affect those stakeholders and ensure valued outcomes for consumers. We will focus efforts on:

- **European Network Codes:** We will continue to provide leadership in the development and implementation of the current European Network Codes programme with the support of our key stakeholders.
- **Clean Energy Package:** We will work with our stakeholders to help them understand the implications of the Clean Energy Package for their businesses by publishing a high-level impact assessment Q2 2019-20.
- **ENTSO-E:** We will continue to actively participate in ENTSO-E to deliver value for stakeholders; this will include active engagement in committees and working groups and regular engagement with other TSOs to share and learn from best practice.
- **EU exit:** We will continue to work with our key stakeholders, including BEIS and Ofgem, to ensure that we are prepared on these topics for EU exit, as well as being prepared much more widely in respect of, for example, security of supply, operability, codes, licences and future relationships.

Unlocking whole system network development opportunities

Our 2018-19 Forward Plan set out opportunities associated with whole system network development thinking and the benefits of reviewing Security and Quality of Supply Standard (SQSS) alongside the *NOA*; we will take forward our thinking on the review throughout 2019-20.

Developing and driving targeted market improvements

We can offer a unique perspective through our role at the heart of the energy system and continue to provide targeted input where we believe our views can add value. We will work with our stakeholders to understand their current and future market framework pain points, identifying potential further code modifications to be raised. We will engage stakeholders further to identify, develop and drive such targeted market improvements, whilst remaining mindful of existing planned changes and the effect this has on industry time and resource.

Defining our deliverables:

We undertake a number of activities to aid the maintenance, improvement and transformation of industry codes whether that be raising housekeeping modifications, driving or facilitating framework changes, or promoting and shaping debate through the sharing of our experience and expertise. We recognise that the markets are continually evolving and that the industry frameworks require constant change and as our thoughts develop in this area so will our deliverables and focus. We have included some of the more mature examples which are expected to provide the greatest consumer benefit and we will continue to review how we best identify, validate and communicate additional deliverables in this area throughout this Forward Plan period.

Deliverable	Description	Delivery Date
Leadership in the successful transformation of electricity access and charging	Publication of ESO-led Balancing Services Charges Task Force final report.	Q1 2019-20
	Leadership in network access and forward-looking charges review.	Ongoing
Leadership in the Energy Codes Review	Publish thought piece on potential future arrangements of the Energy Codes as part of the wider Energy Codes review programme.	Q1 2019-20
Working for you on European matters	Publication of an ESO high-level impact assessment of the Clean Energy Package.	Q2 2019-20
Unlocking whole system network development opportunities	Continue to review potential options under the SQSS review.	Q1 2019-20
Developing and driving targeted market improvements	Continue our review of new commercial security arrangements for long lead time high value transmission schemes.	Q1 2019-20

Facilitate electricity network charging reform through Charging Futures

Consumer benefit outcome

We will engage with current and future users of the Great Britain electricity system to consider current issues across both transmission and distribution arrangements to give more effective reforms, providing an efficiently operating system for the benefit of the end consumer.

Deliverable	Description	Delivery Date
Facilitate electricity network charging reform through Charging Futures 1. Targeted Charging Review 2. Access and Forward Looking Charges SCR 3. Reform of Balancing Services Charges	Facilitate reform of arrangements across the whole electricity system by communicating with all users of the electricity system and creating opportunities for all users to learn, ask and contribute to reform. This will include: • Regular Forums, • Webinars, • Podcasts, • Emails, • Summary notes, • Charging Futures website.	Please see the Charging Futures website – http://www.chargingfutures.com/

Transform the customer experience for network charging

We will continue to focus on the better provision of data and information and removing unnecessary barriers to market entry through improved onboarding processes.

Consumer benefit outcomes

Deliverable	Description	Delivery Date
Improve our ESO charging query processes	Communicate clear routes of contact for all charging queries and publish updated query management standards.	Q1 2019-20
Improve understanding of our onboarding processes and streamline to meet our customer needs	Publish guidance to help and support new suppliers in understanding our charges, our obligations, and what they need to do.	Q1 2019-20
	Simplify our approach for onboarding customers.	Q2 2019-20
	Redefine our processes to make them more customer centric.	Q3–Q4 2019-20
New data reports for BSUoS	Publish new Balancing Services Charging report to show more granular costs by settlement period to enable customers to see different cost components and model future prices.	Q1 2019-20
Reform of website content in to a user-centric knowledge base	Support our increased information provision by improving information signposting on our website.	Q2 2019-20
Publications and guidance of the impact of charging reform to our customers	Significant reform to the charging arrangements are expected over the 2019–21 timeframe. The Charging Futures project helps to facilitate industry input and guide users through reform. Complementary to Charging Futures, we will provide extra guidance on how this will affect users' charges in understandable, real terms.	Ongoing from Q2 2019-20

Introduce new 'new entrant' e-learning on charging	Develop and roll-out a suite of training to support new entrants in understanding our charges.	Q4 2019-20
	Developing and roll-out further training and guidance to help all parties engage and understand charging methodologies.	Q1–Q3 2020-21
Improve the digital customer experience for TNUoS, BSUoS and Connection Charging Data; including the introduction of a new NGESO billing system	We are investigating options for updating our systems, and have a clear drive to put customer functionality at the heart of any new products.	Q1–Q4 2020-21
Establish a 'cross party' approach to onboarding, mapping out whole industry requirements	Work with suppliers to be a critical friend in supporting them starting in the market, for both their obligations with NGESO and with other industry parties such as Ofgem and ELEXON.	Q1–Q4 2020-21

Making Electricity Market Reform (EMR) easier for participants

Consumer benefit outcomes

The European Court of Justice judgement in November 2018 means that the Capacity Market (CM) is in a standstill period until such time that the government achieves approval for the scheme to be restarted. During this standstill period, we continue to believe that a Capacity Market is the correct mechanism to deliver security of supply for GB. In this period, we, as the EMR Delivery Body, will support the Government as they seek resolution. We will work with our customers to ensure we provide guidance with regard to CM obligations. Below, we have set out our planned high-level deliverables for the Capacity Market and will refresh these accordingly in due course.

Capacity Market Customer Journey

Customers have told us that the CM is too complicated and the IT systems that we use as the EMR Delivery Body do not do enough to guide applicants through the process. In 2019-20 we will work with applicants to build on the guidance that we produced in 2018-19. In conjunction with the guidance and the customer support, where possible we will look to make improvements to our systems to ensure performance and improve user experience.

Capacity Market Five Year Review

BEIS and Ofgem have initiated their processes to review the CM five years after its implementation. We believe that the CM has met its core objective to ensure security of supply during times of winter peak demand at the lowest cost to consumers and agree that there is a need for the continuation of the CM. We observe that the CM has undergone significant change since 2014 and is now operating in a very different context. The CM's framework has not evolved at the same pace and cannot adequately support the efficient and effective delivery of the CM, in its current guise.

The five-year review provides a valuable opportunity to consider whether changes to the CM might be required either now or in the future to ensure that it remains fit for purpose. Key areas identified by BIES have been the participation of renewables and the derating factors of interconnectors. Ofgem highlight the requirement to improve the CM's existing framework and governance arrangements and simplification of processes to reduce the burden on Participants. We, as the EMR Delivery Body will fully support these reviews and work with BEIS, Ofgem and industry to implement any resulting change.

Contracts for Difference

In 2019-20, as the EMR Delivery Body, we will facilitate the Contract for Difference (CfD) Allocation Round 3 (AR3). The EMR Delivery Body is working with other delivery partners and potential applications to deliver regulatory changes and improve on the round 2 (2015) process. CFD AR3 introduces new technologies such as remote island wind. We must engage with new and existing applicants to ensure that the process is a success in 2019-20.

It is anticipated that BEIS will conduct a CfD five-year review in 2019-20; we will engage and support this process. We want to ensure that the scheme continues to deliver growth in affordable clean energy.

Capacity Market Modelling – Distributed connected generators in the CM (de-rating factor method)

The original CM was based around the availability of large conventional generation. However, the market place is changing with distributed generation now playing a greater role than ever before. Consequently, it is vital that the contribution to security of supply of this distributed small-scale generation is calculated correctly.

In line with our 2018-19 commitments we have been investigating whether a method for calculating CM de-rating factors for distributed generation utilising Electralink output data by technology, could be developed rather than using the equivalent transmission generation technology de-rating factors as per CM rules. This analysis had been agreed with BEIS and Ofgem as a priority as distribution connected generation is a growing proportion of the generation mix and was also likely to be operating in a more flexible way than the larger transmission connected plant. The development projects final report was delivered in February 2019.

The report concluded that while the half hourly output data from Electralink proved reliable to use there wasn't the equivalent reliable sources of technology type or capacity data available to compare with; hence, developing a method for calculating reliable de-rating calculations proved at this stage to be impossible. We are currently in discussions with a number of organisations to try to obtain the required data but there is no one database available containing all this information in enough detail to be able to cross reference to the output data. Consequently, our modelling will need to continue into our 2019-21 Forward Plan.

Deliverable	Description	Delivery Date
Capacity Market Modelling – facilitating broader participation in the CM to provide security of supply at best value for consumers	Investigate the various sources of technology type and capacity data that would enable a robust method to be developed and implemented into the future. Dependent on investigation improved methodology developed.	Q4 2019-20

How we will measure our performance in 2019-20

Metric 4 – Provider Journey Feedback

This performance metric is measuring the outcomes of the following deliverables:

- Provider experience
- Information provision scorecard

Consumer Benefit

Lowering costs for consumers by driving us to focus on providers and potential providers to reduce barriers to market entry, increasing liquidity in Balancing Services markets. This will also benefit consumers through facilitating the transition to a lower carbon network.

Context

We have made commitments to reform the Balancing Services markets, opening them to new providers. The end to end provider journey has been mapped and key points identified which are onboarding, tendering, contracting and query management.

Metric

Feedback score from the four key points identified in the provider journey:

1. Onboarding Survey Questions
   - 1.1 I found it easy to find the information I needed. On a scale of 1-5, with 1 for strongly disagree and 5 for strongly agree.
   - 1.2 I was provided with information of sufficient quality to enable me to make an informed decision. On a scale of 1-5, with 1 for strongly disagree and 5 for strongly agree.
   - 1.3 What can we do to improve the accessibility of our information? (free comments box).
2. Tendering
   - 2.1 What type of participant are you?
   - 2.2 I have the information I need to understand the service tender results. On a scale of 1-5, with 1 for disagree and 5 for agree.
   - 2.3 What can we do to improve transparency of the service tender results?
3. Contracting
   - 3.1 This area is to be developed during Q1 of 2019-20.
4. Query management
   - 4.1 1.9 This area is to be developed during Q1 of 2019-20.

(Questions 1 & 2 are rated on a 5-point scales: strongly agree to strongly disagree)

Performance Benchmarks

In the absence of any historical data, a benchmark of 2.5 has been chosen as it is the mid-point of the 1-5 rating. However, we will keep this under review as we start to receive feedback, and will revise it as appropriate throughout the Plan period.

Exceeds benchmark: average of 4/5 or above

In line with benchmark: average of 2.5-4/5 or above

Below benchmark: average of less than 2.5/5

Metric 5 – Reform of balancing services markets

This performance metric is measuring the outcomes of the following deliverables:

- *Product Roadmap for Response and Reserve* implementation
- *Product Roadmap for Reactive* implementation
- *Product Roadmap for Restoration* implementation
- Power Responsive
- *Wider Access to BM Roadmap* implementation
- Intermittent generation.

Consumer benefit

Removing barriers and facilitating the entry of non-traditional providers into balancing markets will result in:

- Lower bills than would otherwise have been the case through driving more competitive prices from service providers.
- Reduced environmental damage both now and in the future through increasing market opportunities for low-carbon technologies.
- Unlock additional revenue streams for service providers.

Context

Within our *Product Roadmaps for Frequency Response and Reserve, Restoration and Reactive Power* we outlined deliverables that will deliver equitable markets for each service by removing unnecessary barriers to entry and introducing more open procurement methods.

In response to stakeholder feedback at the mid-year ESO performance panel in November 2018, we have developed a metric that covers the removal of barriers to entry for different technologies in different services. This is supplemented by tracking the distribution of balancing services spend across bilateral and open procurement approaches (competitive tenders and auctions) in order to tell the full story.

Our intention is to use this metric to communicate progress against a fundamental element of role 2 deliverables. We would value stakeholders' view on how to articulate this and benchmark progress in the simplest and most transparent manner.

Framework

Part of our role as market facilitator is to work with parties to develop efficient markets so that they, ultimately, better serve consumers. The activity that is under way to develop balancing markets is on a scale far beyond that normally undertaken. It involves working with more stakeholders than ever before to understand their businesses and open up value propositions for them. We are working hand in hand with stakeholders addressing barriers to entry and tackling new issues. The issues we are tackling are complex and we need to find the right pace to keep up with this market but also continue to make sure the system operates safely.

Through our *Product Roadmaps*, we have committed to reforms to our Balancing Services markets that are essential in enabling us to facilitate the transition to a smart, flexible, low-carbon electricity system.

Metric

Metric part one:

This metric will measure how reforms are facilitating the entry of non-traditional providers into balancing markets. We will map service provider technology types against current services and the accessibility of these services has been categorised into three groups. This assessment is based on feedback from providers through a number of channels, including the *System Needs & Product Strategy consultation*[15], Power Responsive forums, industry working groups, and direct engagement with market providers. Interim solutions are those where there are either some barriers remaining, or manual processes are in place for some users but not others, or other reasons.

- Red – significant barriers to entry with no solution implemented
- Amber – interim solution implemented
- Green – enduring solution implemented to enable commercial access

This metric will be reported on quarterly, with commentary where there are changes to the forecast.

Metric part two:

This metric will measure the direction of travel away from bilateral arrangements, towards open and accessible market opportunities. We have attributed balancing spend to three categories that describe the openness of the procurement approach:

- Commercial (bilateral)
- Mandatory
- Tendered

On a quarterly basis information will be presented in a chart for each service that shows cumulative spend broken down into the three categories of procurement approach to provide supporting narrative on our progress.

Performance benchmarks

Metric part one:

The change of status between ‘current’ and ‘end Q4 2019-20’ is driven by the expected changes from completing relevant role 2 deliverables. These deliverables have been identified as addressing identified barriers to market participation, however there may not be a direct and immediate effect on the market associated with each one. This is because changes in product design or market structures take time to filter through into changes in participant behaviour, and cannot easily be unpicked from natural variations or the impact of external factors such as regulatory changes.

[15] https://www.nationalgrideso.com/document/84261/download

Deliverable in 2019-20	BM Wind through 2019-20					Embedded wind through 2019-20				
	Current	Q1	Q2	Q3	Q4	Current	Q1	Q2	Q3	Q4
Mandatory Frequency Response (MFR)	🟡	🟡	🟡	🟡	🟢	🔴	🔴	🔴	🔴	🟡
Commercial Frequency Response (FFR/auction trial)	🔴	🔴	🔴	🟡	🟡	🔴	🔴	🔴	🟡	🟡
Obligatory Reactive Power Service (ORPS)	🟢	🟢	🟢	🟢	🟢	🔴	🔴	🟡	🟡	🟡
Reserve Products	Consultations and developments will be made throughout 2019-20 for delivery in future years									
Black Start services	Consultations and developments will be made throughout 2019-20 for delivery in future years									
Balancing Mechanism	🟡	🟡	🟡	🟡	🟡	🔴	🔴	🔴	🔴	🟡

Deliverable in 2019-20	Solar through 2019-20					DSR through 2019-20				
	Current	Q1	Q2	Q3	Q4	Current	Q1	Q2	Q3	Q4
Mandatory Frequency Response (MFR)	🔴	🔴	🔴	🔴	🟡	🔴	🔴	🔴	🔴	🔴
Commercial Frequency Response (FFR/auction trial)	🔴	🔴	🔴	🟡	🟡	🟢	🟢	🟢	🟢	🟢
Obligatory Reactive Power Service (ORPS)	🔴	🔴	🟡	🟡	🟡	🔴	🔴	🟡	🟡	🟡
Reserve Products	Consultations and developments will be made throughout 2019-20 for delivery in future years									
Black Start services	Consultations and developments will be made throughout 2019-20 for delivery in future years									
Balancing Mechanism	🔴	🔴	🔴	🔴	🟡	🔴	🔴	🔴	🔴	🟡

The timing of the deliverables is achievable but challenging, particularly for those classed as Exceeding Baseline', and therefore a target of >75% for being above the benchmark has been chosen.

Exceeds benchmark: Completing >75% of deliverables, would constitute the metric exceeding the benchmark.

In line with benchmark: Completing 50-75% deliverables would constitute the metric being in line with the benchmark.

Below benchmark: Completing <50% deliverables would constitute below the benchmark.

Metric part two:

There are no performance benchmarks for the second part of Metric 5, as creating an incentive on the ESO to procure in a certain way would limit our ability to deliver our balancing services at the lowest cost to consumers. However, we believe that reporting the information in a regular and transparent way will allow for more open conversations around balancing services procurement and the effect Forward Plan deliverables have on the markets.

Metric 6 – Code administrator: stakeholder satisfaction

This performance metric is measuring the outcomes of the following deliverables:

- Facilitating code change
- Transform industry frameworks to enable decentralised, decarbonised and digitised energy markets

Consumer benefit

Consumers benefit from competitive markets that reflect the design and use of the networks that connect them. Ensuring that technical and commercial arrangements keep up with changing behaviours and new technologies is critical to facilitating these markets. As code administrator, we have a central role in making the development of technical and commercial codes a transparent and accessible process. Improved performance in our code administration function enables all network users to contribute more effectively to future arrangements.

Context

We are code administrator for three codes: Connection and Use of System Code (CUSC), System Operator Transmission Owner Code (STC) and Grid Code. There are increasing numbers of parties in the electricity industry that have an increasing variety of needs and preferences. As a code administrator, we believe that we can do more to keep people informed of how our frameworks are being developed and creating opportunities for network users to contribute to their development.

The most recent half year CACoP survey highlighted an improvement in our performance across the three codes we administer. Whilst this is progress in the right direction, we are committed to the ambitious strategy we have set ourselves. This included the publication of an improvement plan in October 2018 focused on the ease of interpreting information, technology & facilitation and the provision of support.

For 2019-20, we continue our journey of getting the basics right but will increasingly focus on more value-added activities that will support network users to stay better informed and build a greater understanding of developments and hence enable more effective contributions to the code change process.

Metric

In line with our Forward Plan engagement feedback, we recognise that there is no single representative measure for performance. We have therefore expanded our framework to measure performance in this area:

- **CACoP survey** -We will continue to use the results from Ofgem's annual CACoP survey as the baseline for our performance in this area to demonstrate the impact our deliverables are having. At present, there is currently a disconnect between the publication of CACoP survey results and the performance year. Through discussions with Ofgem and CACoP, we intend to investigate whether the timing of the CACoP survey results can be aligned with the financial year.
- **Stakeholder surveys** – We will supplement our assessment of performance by undertaking stakeholder surveys following key activities to ask how likely they are to recommend the service provided to colleagues. By doing this we will be able to understand how well each of these activities are meeting the needs of our stakeholders. Conscious of "survey fatigue" we will schedule these around key outputs and look to minimise burden on the stakeholders we are seeking feedback from. Our baseline will be based on average survey scores taken at the end of the 2018-19 period as these scores are still subject to feedback we will publish our final baseline score during our first 2019-20 monthly ESO incentive performance report.
- **Delivery of outputs** – Lastly, we should be measured on the delivery of our promised outputs

Performance benchmarks

Exceeds benchmark:

- Increased overall performance across all our three codes (STC/CUSC/Grid Code) in the 2020-21 CACoP survey due to be carried out in spring 2020; benchmarked with our previous scores.
- All exceeding baseline deliverables achieved to plan.
- Stakeholder survey taken periodically throughout the year - Increased overall performance across all our three codes (STC/CUSC/Grid Code); benchmarked with our previous scores.

In line with benchmark:

- Increased overall performance across all our three codes (STC/CUSC/Grid Code) in the 2020-21 CACoP survey due to be carried out in spring 2020; benchmarked with our previous scores.
- All exceeding baseline deliverables achieved to plan.
- Stakeholder survey taken periodically throughout the year - Increased overall performance across all our three codes (STC/CUSC/Grid Code); benchmarked with our previous scores.

Below benchmark:

- Maintained performance across all our three codes (STC/CUSC/Grid Code) in the 2020-21 CACoP survey due to be carried out in spring 2020; benchmarked with our previous scores.
- All baseline deliverables delivered to plan.
- Stakeholder survey taken periodically throughout the year - maintained performance across all our three codes (STC/CUSC/Grid Code); benchmarked with our previous scores.

Metric 7 – Charging Futures

This performance metric is measuring the outcomes of the following deliverables:

- Facilitate electricity network charging reform through Charging Futures

Consumer benefit

By supporting current and future network customers through change, Charging Futures will help realise benefits to the end-consumer by:

- Stimulating competition and facilitating an expanding market – reducing barriers to entry for new customers, leading to greater choice and enhanced service for consumers.
- Managing a complete and collaborative cross-system change process – allowing the industry to fully understand how a new charging and access regime can drive the most efficient use of the network, while recovering costs fairly for consumers.

Context

Our role as lead secretariat for Charging Futures allows us to exhibit our proactive stance in helping the industry to best engage with charging reform. Our performance should be judged on how well we can enable the industry change process. This will be measured by outcome-focused performance indicators.

We have committed to three engagement objectives to best support industry through Charging Futures. Every network user, no matter their size or where they are connected to the electricity network, has the opportunity to:

1. Learn – about electricity network charging across the whole system today, and how it could change in the future.
2. Ask – regularly ask charging and regulatory experts questions related to reforms, and wider charging code change.
3. Contribute – be able to contribute to reform at all stages and through a number of ways.

Framework

To demonstrate how we have met these three engagement objectives, we will use a combination of outcome-focused measures. These are outlined in the table below. We will survey the full Charging Futures membership list (currently over 500 members) and will assess our performance based on the three primary measure questions.

Engagement objective with industry	Desired outcome	Primary measure (survey question)
Learn about electricity network charging across the whole system today, and how it could change in the future	• A wider range of industry participants have a better understanding of how charging works today – particularly smaller and newer players • Industry knows what and when change might happen in electricity charging and access arrangements • Industry feels better able to 'contribute' to sessions because of an increasing knowledge base	Through Charging Futures, to what extent do you feel you've had the opportunity to improve your understanding of electricity network charging arrangements, current developments, and the options for change in the future?
Regularly Ask charging and regulatory experts questions related to upcoming reform	• Industry acknowledges and appreciates an increasing opportunity to ask questions of charging and regulatory experts	Through Charging Futures, to what extent do you feel you've had the opportunity to ask charging and regulatory experts about potential change?
Be able to Contribute through the differing stages of reform	• A wide range of network users are contributing to reform at all stages, through Charging Futures • Participants are satisfied with the number of opportunities and range of routes through which they can contribute to reform • The quality of contributions from a greater number of industry participants has improved when compared to previous consultations and code work groups • Industry has multiple ways to feedback and develop the Charging Futures process to best benefit it	Through Charging Futures, to what extent do you feel you've had the opportunity to contribute to high level changes around future Great Britain charging and access arrangements?

Following key engagement activities, we will also survey attendees to ask how likely they are to recommend the activity to colleagues. By doing this we will be able to understand how well each of these activities are meeting the needs of our stakeholders.

Metric

Baseline score – through Charging Futures we have actively sought immediate feedback from industry participants for all our Charging Futures Forums and Webinars. The results of these have been actively shared throughout the year in our 2018-19 Incentives Framework reporting. Baseline performance will be based on the average feedback scores received throughout performance year 2018-19. At the time of publication our indicative baseline score is 7.3 (on a score from 1-10). As

Charging Futures events are still ongoing we will publish our final baseline score during our first 2019-20 monthly performance report.

Our success as lead secretariat should be judged against our ability to maintain the overall scores for these measures throughout the year. This will be calculated by periodically repeating the survey throughout the year and averaging these scores. These scores will then be compared against the initial baseline score.

Performance benchmarks

Exceeds benchmark: Average scores from surveys undertaken throughout the year are higher than the baseline score.

In line with benchmark: Average scores from surveys undertaken throughout the year equal the baseline score.

Below benchmark: Engagement scores achieved throughout the year fall below the baseline score.

As further evidence of the outcomes that we are achieving for Charging Futures members, we will supplement the primary survey measures through the continued collection of supporting metrics. Many of the secondary metrics will be determined through an assessment of the utilisation of the Charging Futures web portal[16].

Metric 8 – Year ahead forecast vs outturn annual BSUoS

This performance metric is measuring the outcomes of the following deliverables:

- Information provision scorecard

Consumer benefit

An annual BSUoS forecast is vital for those parties seeking to price long-term products such as electricity suppliers providing fixed price supply contracts to domestic consumers. The better the forecast the lower the risk premia that need be added to the supply contract and as a result the lower the cost for the end consumer.

Consumer benefit outcomes

Please see case study 2 in appendix C.

Context

The nature of BSUoS and the impact that significant and unexpected events during the year can have on the cost of system balancing means that there is significant uncertainty in an annual forecast. An event such as £18m spend on margin over 3 days, or significant fault outages like HVDC can cost tens of millions of pounds. Our incentive performance could easily be lost by an event could happen on day two of the incentive period. It is this level of uncertainty that has informed our development of thresholds across which our performance will be measured.

Metric

This metric compares the BSUoS forecast made at the start of the financial year against outturn using the concept of an Absolute Percentage Error (APE)[17].

Performance benchmarks

Exceeds benchmark: exceeding target is under 10% APE.

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[16] http://www.chargingfutures.com/

[17] APE = abs((Actual – forecast)/ actual). APE calculates the difference between actual and forecast divided by the actual to give a percentage error, the absolute value is take to account for positive and negative errors.

In line with benchmark: proposed baseline target is less than 20% APE.

Below benchmark: underperforming greater than 20% APE.

Performance can be driven by within year events so we won't have a clear picture of the result until the end of the year. We therefore don't expect to report on this measure on a monthly basis and introduce metric 9 at a monthly granularity.

Metric 9 – Month ahead forecast vs outturn monthly BSUoS

This performance metric is measuring the outcomes of the following deliverables:

- Information provision scorecard

Consumer benefit

Some of our customers have told us they manage their price and balancing risks via month-ahead products. We also understand large consumers on pass-through contracts seek to understand their month-ahead BSUoS costs. For both of these reasons the quality of our month ahead BSUoS forecast can influence the risk premia that parties are having to manage with the ultimate benefit of reducing consumer cost.

Consumer benefit outcomes

Please see case study 2 in appendix C.

Context

There is significant volatility in the comparison of our month ahead forecast with the outturn. If we examine the percentage variance, then there can be large swings in accuracy. We propose that to ensure we are continually incentivised to improve our forecast that this metric does not just look explicitly at the volatility but at the number of occurrences outside of a 10% and 20% band. This means we will be appropriately incentivised to avoid very high errors.

Our thresholds have not been established based on historic performance: the data below shows that in 2017 we wouldn't have met either threshold, we therefore consider Metric 9 to be a realistic measure of our potential performance.

Please note that we provide a narrative on the monthly volatility in the BSUoS report published on our website, and can explain why a month's error is outside the target range due to unforeseen events.

Metric

The metric will count the occurrences of absolute percentage error (APE) for our monthly forecast with outturn data available at month end

Performance benchmarks

Exceeds benchmark: Exceeding is meeting baseline performance and five or more forecasts less than 10% APE.

In line with benchmark: Of the 12 forecasts over a financial year, baseline performance is less than five forecasts above 20% APE.

Below benchmark: five or more forecasts above 20% APE.

3&4.

Facilitating whole system outcomes and supporting competition in networks

Roles 3 & 4
Facilitating whole system outcomes and supporting competition in networks

Coordinate across system boundaries to deliver efficient network planning and development

Coordinate effectively to ensure efficient whole system operation and optimal use of resources

Facilitate timely, efficient and competitive network investments

Our whole system ambition

Our overarching ambition is that the planning, development, investment and operation of Great Britain's networks will be optimised on a whole system basis, irrespective of ownership boundaries. Solutions to ESO challenges will be open to a full range of participants, facilitating both market and asset solutions; and we will work to deliver best overall value for consumers, irrespective of the ESO or Distribution System Operators (DSO) performing the analysis. A possible end-state for this approach can be seen in *Figure 1.*

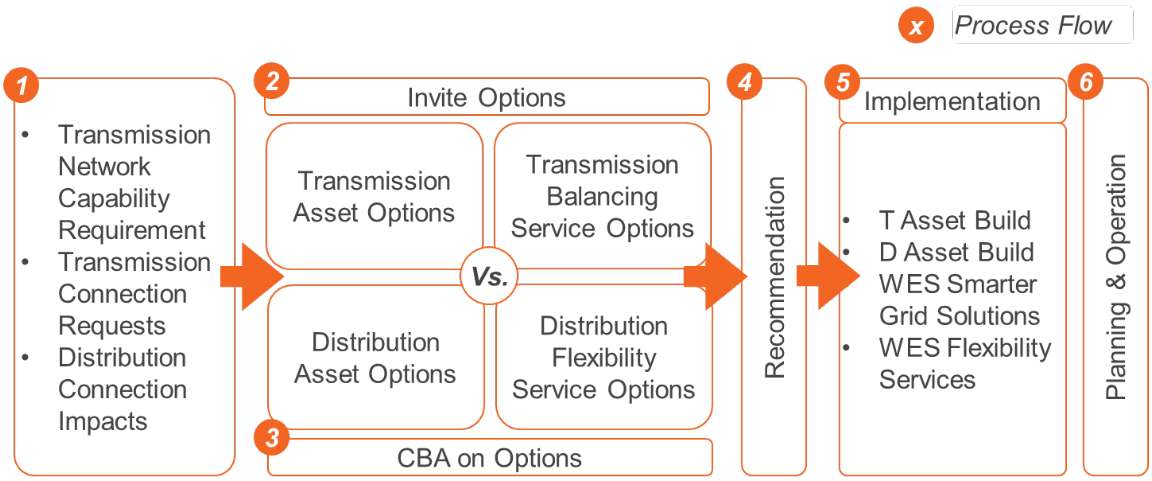


Figure 1

This stylised representation of the processes involved in connecting to, developing and operating the electricity networks shows how we envisage a whole system approach working. It drives consumer benefit by considering a broad range of asset and operability solutions to system issues. Looking across transmission and distribution, it allows us to understand where the gaps are relative to current processes, and guides the activities we will undertake during 2019-21 in order to fill them. These activities are explained at a high level below, after which we focus on how those activities translate into specific deliverables for 2019-21.

Network investment

Through our investment processes, we support the transition to a low-carbon network. We currently do this by recommending the most economical transmission network solutions, based on analysis of onshore, offshore and potential cross-border options.

Decentralisation of the electricity system opens a wider range of approaches across the transmission and distribution systems to find new and novel solutions to current and future challenges. Effectively meeting those challenges depends on coordination and collaboration across network boundaries.

Currently, efficient transmission network investment is shaped by the data we hold and the modelling we undertake to provide future transmission system needs information for the industry. This is illustrated in orange in *Figure 2.*

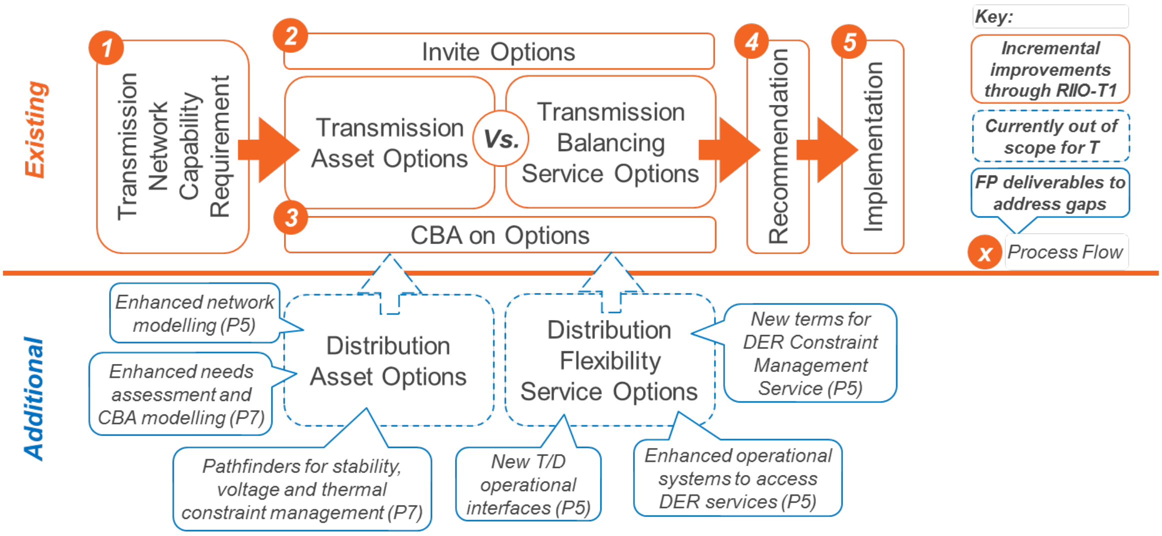


Figure 2

We work seamlessly with the DSOs, through new markets and processes, to explore all possible solutions for meeting transmission system needs to design the network we need by 2030. These needs will include both asset and operability based solutions, which will be optimised alongside distribution system needs to deliver best value for consumers regardless of asset ownership boundaries.

To do this, we need to develop ways for distribution asset options and distribution flexibility service options to be considered alongside transmission equivalents, so that a true whole system assessment of all viable options can be undertaken, to determine the economically and technically optimum solutions. This requires us to deliver the additional (blue) activities in Figure 2.

Through these additional activities, we will expand the *NOA* process to include solutions to network development challenges from network and non-network providers across transmission and distribution, expanding the range of system needs that a *NOA*-type approach is applied to. Solutions to network development challenges may include commercial solutions and distribution network solutions in addition to traditional transmission network build options. Our Network Development Roadmap published in July 2018[18] signposted these changes to support greater participation in the NOA and support competition.

Network connections

We want to improve our customer's experience and ensure they have full visibility of how to access and use the networks from the time of their initial connection and throughout the operating life cycle of their assets including maintenance and refurbishment programmes.

[18] https://www.nationalgrideso.com/sites/eso/files/documents/Network%20Development%20Roadmap%20-%20Confirming%20the%20direction%20July%202018.pdf

The types of customers connecting to our networks have changed, this brings a more diverse range of services and with that the levels of support provided through the connection process and the contract management phase of the connection require a change of approach. We will work with customers through the early phase of their investment to ensure the connection point offered reflects the best whole system outcome and the quality of the contract provides the ability to connect swiftly.

Currently, transmission network connection requests follow a structured process that is enshrined within the CUSC. This is illustrated in orange in *Figure* 3.

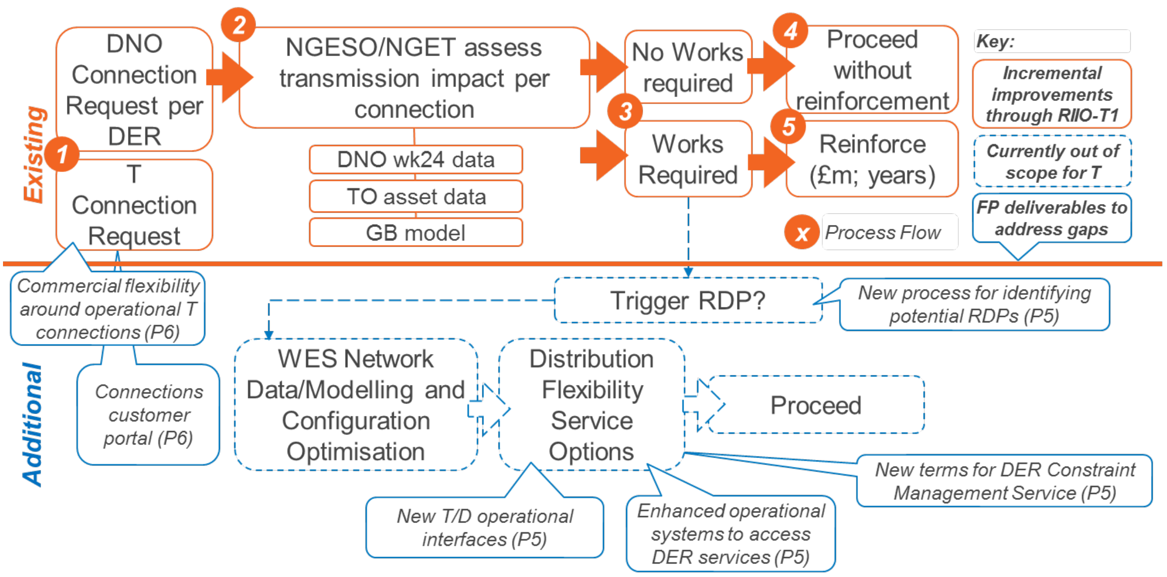


Figure 3

As volumes of distributed energy resources (DER) continue to increase, we have collaborated with industry to deliver as much flexibility as possible within the existing CUSC processes. The 2018-19 Forward Plan contained activities that deliver an enhanced approach to agreeing bilateral contract terms with DNOs to enable further connection of DER. In the context of a broader 'connect and manage' approach, these changes have set the scene for us to deal with the consequences of additional DER connections without the need to build additional assets. However, to ensure we have the capability to 'manage' the consequences of these connections, we need to undertake the additional (blue) activities in *Figure 3.*

Through these additional activities, we will enhance our ability to manage the consequences of additional transmission and distribution connections. By developing additional operational and commercial tools and techniques, we will improve the efficiency of system operation whilst also enabling DER to participate in a range of system operator services markets. Further, we will strengthen our relationships with DNOs, evolve the way we work together and support them as they transition to become DSOs.

Network planning & operation

We want to develop ways of working and processes that enable whole system planning and operation, and ensure that we find ways to make the best use of all resources available across the system.

A highly-stylised overview of key transmission planning and operational activities is presented in *Figure 4,* with existing activities in orange. In simple terms, the process seeks to ensure the secure operation of the system in light of expected generation and demand patterns, whilst at the same time facilitating access to allow for investment and maintenance work to be undertaken.

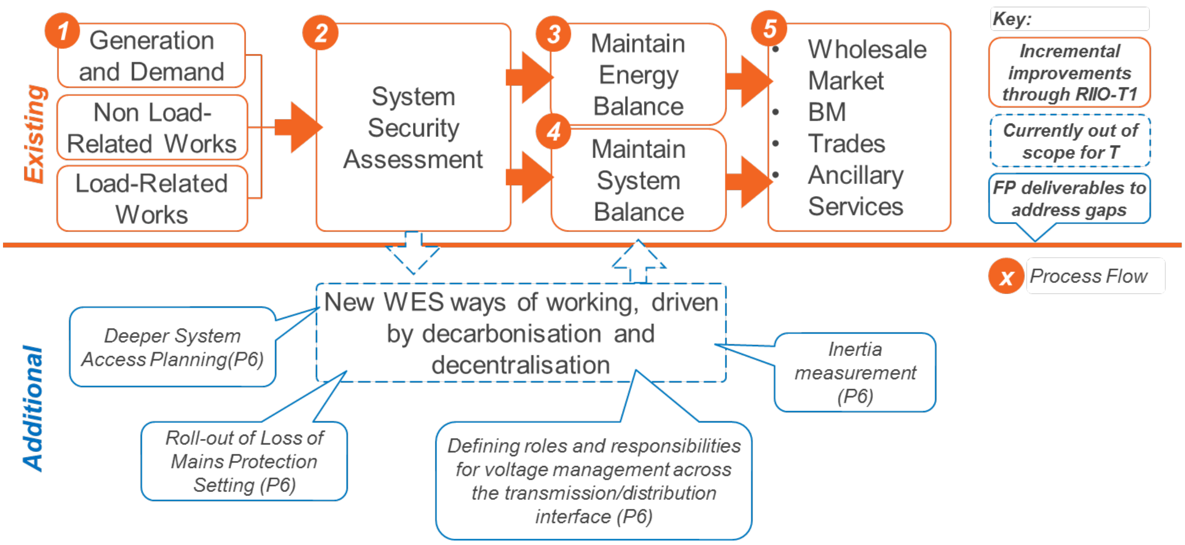


Figure 4

As the generation and demand patterns shift to reflect the ongoing low-carbon transition, the tools and services that support our system operation activities change as well. For example:

- Reducing levels of synchronous generation have led to a corresponding reduction in system inertia, which in turn has required us to spend increasing amounts on services to manage the consequences;
- Increasing volumes of DER and shifting demand patterns have changed the voltage characteristics of distribution networks, which has had an impact on transmission voltage management; and
- Sensitive loss-of-mains protection on DER has resulted in instances of incorrect operation following system disturbances at transmission-level, resulting in more severe frequency deviations that cost more to manage than would otherwise be the case.

These, and other, operational phenomena are examples where a more whole-system approach is required to deliver the most efficient outcome for consumers. To account for them, we need to undertake the additional (blue) activities in *Figure 4.*

Through these additional activities, we will deliver new ways of working across transmission and distribution, far beyond existing codified arrangements, and new approaches to dealing with existing and emerging issues, clarifying roles, responsibilities and supporting mechanisms.

We will work with DNOs to allow access to a wider range of resources and operational tools, whilst managing the technical challenges presented by operating the system in ways that were never anticipated when it was built. Many of these activities require new roles and responsibilities to be established, and routes agreed to enable them to be funded – generally in ways that weren't previously envisaged.

To optimise benefits to the consumer, we will collaborate widely across industry with other network operators including TOs, DNOs and an increasingly diverse range of customers to find creative solutions to operating challenges that traditionally would be solved through balancing actions in the Balancing Mechanism.

Delivering consumer benefit

Network investment

Our aim is to reduce consumer bills through ensuring we identify and evaluate all options for network development. Through evaluating a range of solutions using a *NOA*-type approach we will be able to identify options that are the best value for consumers.

In the *Network Development Roadmap,* we said over the next two years we will focus on expanding the *NOA* process to evaluate a wider range of options. We identified work that we would do that has now extended to six specific programmes at this point: stability pathfinder, voltage pathfinder, voltage screening tools, thermal constraint assessment tool, constraint management pathfinder and enhanced communication.

Pathfinder projects will identify solutions to transmission operation challenges and promote a wider range of commercial solutions to meet the challenges. This will drive reduced costs of operating the network through more efficient solutions to issues such as high volts. A wider range of solutions combined with enhanced modelling capability, to better accommodate changing supply and demand dynamics, will also facilitate optimal network development investment.

Promoting competition in the provision of balancing services will help facilitate least cost solutions to allow DER to participate in energy and services markets, enhancing liquidity to drive down costs, and help to get the most out of existing network infrastructure by optimising the use of existing network capacity and minimising the cost of operating the system.

The cost of transmission network installation and maintenance is recovered from transmission-connected generators and suppliers (demand tariffs) via the TNUoS charge which ultimately is passed on to the end consumer. We play a fundamental role in recommending the optimum options to develop the networks, and searching for new ways to identify more options including reduced or no build options. This should put downward pressure on this charge.

Network connections

Consumers can benefit from the early connection of new generation in areas of the network which, without significant asset investment, there has previously been limited opportunity for new connections. Our Regional Development Programmes (RDPs) facilitate this; the increased market participation that results should bring price benefits through increased liquidity; and should also support the achievement of low-carbon objectives (as much of the new distributed generation will also be low-carbon).

Succeeding in this area will benefit consumers in several ways including, identification of the most economic and efficient parts the network for new connections to be made, resulting in quicker connection times and ultimately lower costs to the electricity consumer. This approach will also facilitate a faster route to connection enabling low-carbon targets to be achieved quicker and enabling new revenue streams to emerge for DER.

Over the next two years we will focus on establishing further RDPs across Great Britain, as a vehicle to enhancing the types of consumer benefit we have outlined. We will develop a process to more systematically identify new RDP opportunities across Great Britain.

Network planning & operation

Successful delivery of our operational role on a whole system basis will unlock huge benefits for consumers well in to the future. We will optimise use of energy resources and existing network assets to minimise costs of operating the network, with the aim of enabling greater liquidity in energy and services markets due to enhanced market access and participation. We will develop new ways of tackling operability issues that deliver more cost-effective outcomes.

We will support the development of tools and techniques for system operation of distribution networks to help understand how we will need to change to ensure efficient whole electricity system outcomes. Through driving better service for customers and efficient connection processes to reduce industry costs, we will deliver a secure and economically operable system fit for future needs.

The cost of operating the system is paid by generators and suppliers via the BSUoS charge, which is captured in end-consumer bills. Success in this area will allow us to put downward pressure on this charge, for example by finding new and innovative ways to optimise the use of assets across the whole system for system operation needs.

We will also look across longer timescales at how we can operate the system efficiently as it transforms with low-carbon and decentralised generation supplying changing consumer demand patterns, ensuring the system is fit for consumer expectations in 2030 and beyond.

Role 3 & 4 Facilitating whole system outcomes and supporting competition in networks

NEED INTRO LINE

	Our long-term vision is…	In 2019-21, we are going to deliver…	Benefitting energy consumers now…	… and in the future	
Driving the whole energy transition	**We will optimise planning, development, investment, and operation of GB energy networks, irrespective of ownership boundaries. We will bring our expertise, to complement that of others, and to drive industry as it navigates a complex energy transition. We will facilitate informed decision making that accounts for whole system impacts and minimises unintended costs or consequences.**	Whole electricity system thought leadership.		Ensuring an economically operable system fit for future need and able to securely accommodate changing energy supply and demand patterns. We will contribute to consumer savings of hundreds of millions of pounds per year by 2030.	10
		Commercial contracts for balancing services from DER.	Promoting competition in energy and services markets with value realised as developments come online and lower constraints management costs, most value delivered in future years.		9 £350m
		Enhanced systems to facilitate balancing services from DER.	DER integrated in to network managementwith value realised as developments come on line . Greater participation of low carbon DER in marketswith value realised as developments come on line.		
		Automated dispatch capability for generation in highly constrained areas & RDP identification process.		Optimised network operation and planning to get the most out of existing network infrastructure. Resulting in lower constraints management costs and lower network development costs with reduced build on the network.	
		Whole system operability & data exchange.	Enhanced market access and participation across transmission and distribution promoting competition in energy and services markets.		
				DER integrated in to network management supporting the transition to a low carbon energy system.	
				Lower constraints management and network development costs through identification of efficient operability solutions	
	We will reduce friction for participants in their interactions anywhere on the electricity network, for example whether connecting to the transmission or distribution network, accelerating the efficiency and effectiveness of the energy transformation.	Enhanced customer experience.	Through fast and efficient connections and system access process reducing connection costs, creating enhanced market liquidity and allowing the system to be operated more efficiently. This will also support the transition to a low carbon system allowing renewable resources to be available earlier.		
Unlocking consumer value through competition in networks	**We will facilitate competition across all dimensions – enabling all viable options to compete for delivery of solutions to network problems. We will remain technology-agnostic, selecting solutions based on the consumer value they can deliver.**	Use enhanced study tools to assess the year-round transmission needs.		Promoting a wider range of commercial solutions to operational challenges and reducing cost of operating the network and lower network development costs.	11 Up to £1bn
		NOA: enhanced communication.	Improved network modelling to analyse the highest priority scenarios reduced cost of operating the network, most value delivered in future years .		
		Lead pathfinder projects to develop the necessary processes to support delivery of new whole system ways of working.		Lower network development costs.	12 £36m
			DER integrated in to network management, most value delivered in future years.		

Through our case studies in appendix C, we estimate we will deliver the following value for consumers

KEY 9 Case Study 9: Whole system approach to cross boundary working 10 Case Study 10: Whole electricity system thought leadership 11 Case Study 11: Adding commercial solutions to the NOA process 12 Case Study 12: High voltage pathfinder

Exceeding baseline expectations

Under roles 3 & 4, over the next two years we will take actions that go beyond those expected of an efficient and competent system operator to unlock additional consumer benefits:

- ***Whole electricity system thought leadership;*** Taking a whole system view of the changing energy landscape will deliver deep benefit to the end consumer. Developing and delivering whole system solutions requires collaboration between all stakeholders including network organisations. We are pivotal to these discussions, through our thought leadership in both technical and commercial fields we can provide unique insight and experience to support the transition to the low-carbon whole system.
- ***Pathfinder projects;*** We are acting to address the operational challenges of increasing DER connections by identifying specific areas where we can take action by looking at localised and regional issues. We subsequently aim to formalise the learnings and processes into the NOA methodology. We are taking a 'learning-by-doing' approach to ensure we unlock most benefit for consumers and have identified areas where this approach can deliver value, such as regional voltage issues and stability issues.
- ***Study tools;*** The amount of embedded generation connecting makes the study of voltage on the system increasingly challenging. We are creating better voltage evaluation tools to address these challenges, and studying the system across a range of energy scenarios in order to be able to tailor solutions to the system as it develops. Our new tools will allow us to undertake multiple analyses of the network more quickly, and highlight where problem areas are. Once problem areas are identified, we can then use traditional approaches and tools to fully understand the problems. We are also creating probabilistic network assessment and modelling approaches which will allow us to consider network thermal issues very quickly, taking consideration of stochastic modelling of renewable resources, using probabilistic techniques and network analysis within a single tool. This has the benefit of providing a rich picture of information of the network which will allow us to make informed decisions for the benefit of consumers.
- ***Ongoing RDPs and identification process for RDPs;*** A lot of the change we see across networks today comes from the distribution level, where significant quantities of DER are connecting, and this is having significant impact on the operation of the whole system. We are increasingly looking to distribution resources to resolve issues at transmission level and across the whole system; we want to support our distribution stakeholders as they move towards distribution system operation models. If we can access resources and providers across the whole system, we can pursue the most optimum economic solutions for the consumer. Flexibility is key, and we want to offer the opportunity to flexibility providers to sell their services across multiple complementary markets. We will develop much closer relationships with all networks and stakeholders to collaborate to determine what areas need attention across the whole system. We will identify new innovative ideas and collaborate to take the best solutions forward. We will prioritise the system needs we identify to best utilise our resources.
- ***Whole system operability and data sharing;*** We are continually changing our operating approaches, seeking new ways to adapt to the system challenges brought about by the move from strategically located synchronous thermal generation over the past decade to the network we operate today which includes over 30GW of renewable non-synchronous generation dispersed across the Great Britain network. Whilst we manage emerging and ongoing operability issues through commercial actions, we will do more to reduce, control, and eliminate spend where possible. We are actively identifying and finding solutions for areas which previously didn't cause significant problems, such as power flows from distribution to transmission levels, voltage profiles across all networks, and low levels of system inertia. We are being open to solutions from anywhere across the system, where we can demonstrate the best value for the consumer. We are working down to the level of specific network circuits, to look for solutions (for example active network management) to manage flows in very regional and local locations. This is a new approach when compared with the traditional approach of applying a blanket security standard to all situations. We are moving to developing the system

on a more real-time basis, as opposed to studying how we can operate the system based on a fixed contracted connected generation figure.

- ***Deeper system access planning;*** We believe that greater value can be delivered through deepening our relationships with network owners across the whole electricity system as well as connected parties. This will ensure they better understand the operational impacts of access and that we can better account for costs they could incur through loss of access to equipment or inadequate planning. This co-ordinated planning is resource intensive requiring project delivery discussions as well as increased forecasting and monitoring of the operational impacts of system outages.
- ***Customer connections portal;*** The transition to a low-carbon, decentralised energy landscape has changed who our customers are, bringing a more diverse range of services. To support this transition, we are changing the way that we engage and support our customers, enabling them to be more informed by ensuring they have full visibility of how to access and use the networks from the time of their initial connection through the operating life cycle of their assets including maintenance and refurbishment programmes.

Activities and deliverables 2019-21

	Network investment	Network connections	Network planning & operation
To deliver our whole system ambition, over the next two years we will focus on the following:			
Whole electricity system thought leadership	✓	✓	✓
Ongoing RDPs • Commercial contracts for balancing services from DER • Enhanced systems to facilitate balancing services from DER	✓	✓	✓
Development of a proactive RDP identification process		✓	
Pathfinder projects	✓		
Study tools	✓		✓
NOA: enhanced communication	✓		
Whole system data exchange • Extended roll out of enhanced whole system data exchange • Commercial flexibility around operational connections		✓	
Whole system operability • Roll out of Loss of Mains Protection setting • Defining roles and responsibility for voltage management across the transmission-distribution interface • Inertia measurement		✓	✓

	Network investment	Network connections	Network planning & operation
Deeper outage planning			✓
Enhanced customer experience • Transmission Outage and Generator Availability (TOGA) replacement • Customer journey mapping – outage planning • Connections customer portal		✓	✓

Whole electricity system thought leadership

Our vision of the future energy landscape is based on a world where we work closely with DSOs to ensure routes to local, regional and national markets are aligned and optimised collectively for all participants creating value for the end consumer[19]. We recognise that this future will develop over time. Through the period 2019-21 we will:

Consumer benefit outcomes

Please see case study 10 in appendix C.

- Build on our thought leadership to provide clear articulation of how our role will change through the next decade. Through the RIIO-2 process, we will define our role and deliver against our business plan.
- Share learnings from initiatives such as RDPs as well as our innovation projects such as Power Potential to inform industry thinking.
- Work with others including continuing our key role in the ENA Open Networks project. This will include ESO representation on all relevant Open Networks deliverables, leading where appropriate. Further details on these activities will be provided as the 2019 work programme is confirmed. This will include a lead role in the proposed Whole Energy System workstream.
- We play a key role in the ENA Open Networks project, and will be actively involved across all workstreams and the majority of its 2019 deliverables. We will continue to support this project and identify areas for us to take a lead on. Across the ENA Open Networks workstreams, we are engaged in over 30 working groups and/ or product development groups.

Deliverable	Description	Delivery Date
ESO thought leadership – how our role will evolve	Describe how our role will change over the next decade to meet the challenges of whole electricity system.	Q1 2019-20
Whole electricity system learnings	Describe how our initiatives and innovation projects are supporting whole electricity system thinking and identifying potential new areas of work.	Q2 2019-20, update Q2 2020-21
ENA Open Networks project 2019 ESO input	We will play a proactive role in the ENA Open Networks Project including leading the development of a number of products.	Q3 2019-20

[19] The UK could save £17-40 bn across the electricity system from now to 2050 by deploying flexibility technologies, 'An analysis of electricity system flexibility for Great Britain', Carbon Trust / Imperial College London, November 2016

Deliverable	Description	Delivery Date
ENA Open Networks project whole energy system lead	Lead the development of the whole energy system workstream of the Open Networks project.	Q3 2019-20

Ongoing Regional Development Programmes

Consumer benefit outcomes

Please see case study 10 in appendix C.

A key focus of our first RDPs in the South-West and South-East of England was to allow new DER to connect earlier than would otherwise have been the case if asset solutions were required, by promoting participation in balancing services markets. The aim is for this to increase competitive pressure on existing market participants for relevant services, which should lead to lower prices submitted to us, delivering value for consumers. The identification of operability solutions as an alternative to network asset solutions avoids costly network upgrades and allows DER to participate in markets much earlier than otherwise would be possible. During 2018-19, we commenced the delivery phase of these two RDPs, seeking to establish the technical and commercial arrangements that will underpin these new connections. We will continue this work into the 2019-21 period.

Deliverable	Description	Delivery Date
Commercial contracts for balancing services from DER	Implementation of new commercial contracts to allow DER to participate in the provision of transmission constraint management services in our in-flight RDP areas.	Q4 2020-21
Enhanced systems to facilitate balancing services from DER	Implementation of enhanced systems and ways of working between transmission and distribution to support provision of transmission services by DER	
	DER MW dispatch capability between NESO, DNOs and DER	Q4 2020-21
	Intertripping of DER for transmission fault management	Q3 2020-21
Automated dispatch capability for generation in highly constrained areas	Development and implementation of Generation Export Management Scheme (GEMS) in South-West Scotland to manage transmission constraints using large volumes of additional transmission-connected renewable generation in an economic and efficient way.	
	Intertripping of DER for transmission fault management	Q1 2020-21
	Implementation of GEMS in accordance with agreed plan	Q1 2021-22
	Development of suitable interface with DNO Active Network Management scheme in South-West Scotland to incorporate efficient despatch of embedded generation for transmission constraint management	TBC through our reporting

How does this build upon 2018-19 Forward Plan

The 2018-19 Forward Plan included the conclusion of the design phase of the first two RDPs and their transition to delivery. The delivery phase centred around the development of new technical and commercial tools, required to deliver the visibility and controllability of DER we need to efficiently manage transmission constraints in affected areas.

The dates proposed for those deliverables were based on several technical and commercial assumptions. As the year progressed, it became clear that some of the commercial questions, for example around roles and responsibilities across transmission and distribution, would be more complex to resolve than previously understood; this impacted the technical solution, which had encountered its own delays as well.

However, the opportunity arose to consider the third RDP, Dumfries & Galloway, alongside the first two, from both a technical project and commercial service perspective. The 2019-21 Forward Plan therefore builds upon the 2018-19 activities to deliver an efficient technical and commercial solution.

Development of a proactive RDP identification process

To date, we have launched RDPs in response to system opportunities which have been identified as a consequence of either network licensee connection or investment planning processes. We believe that further value can be generated by taking a proactive approach working with DNOs, TOs and service providers to develop a process that will collaboratively identify future system needs and therefore opportunities for RDPs. This scope of this process will be broader than established connection and network investment frameworks thus ensuring that the highest value opportunities are made visible and can be explored effectively.

Consumer benefit outcome

Please see case study 10 in appendix C.

Through this deliverable, we will agree the form of a systematic process to identify needs cases for further RDPs, to 'productionise' what has so far been a 'learning by doing'; project-based approach. This will enable us to be consistent in our approach, and ensure we can capitalise on all opportunities.

Deliverable	Description	Delivery Date
RDP identification process	An agreed process with DNOs to identify the need for future RDPs.	Q3 2019-20

Pathfinder projects

A pathfinding project is a 'trial by doing' approach to develop new processes, expand capabilities and learn along the way often requiring collaboration between us, TOs and DNOs. They build upon work previously undertaken, for example through RDPs or ENA Open Networks project, to develop the necessary processes to support delivery of new whole system ways of working consistently across Great Britain.

Consumer benefit outcomes

Please see case studiy 12 in appendix C.

We use pathfinding projects to develop the capabilities that we and other parties need to take forward expanding our approach to network development. Developing a cost-benefit analysis that compares network and non-network solutions that have different lifetimes or contracting periods will be challenging and we will develop our approach through pathfinding projects. This will include developing processes for working with a wider set of stakeholders and exploring the value reflected by different length contracts, particularly when the provision of new, long-term market solutions is being considered.

Deliverable	Description	Delivery Date
Stability pathfinder	Assessing a range of commercial and network solutions to meet system stability needs. When we refer to stability in this context we are talking about the stability of frequency, voltage and the ability of a network user to remain connected to the system during normal operation, during and after a fault. We will develop and test processes to define requirements of transmission system stability needs, focussing on dynamic volts, inertia and fault levels as an indication of system stability requirements. We will develop and test processes to obtain and evaluate options to meet the requirements set out through technical and economic assessment. We will develop a methodology for inclusion in the NOA methodology for 2020-21.	Request for Information (RFI): Q2 2019-20 Output of stability pathfinder: Q4 2019-20 Inclusion in NOA Methodology: Q1 2020-21
Mersey Voltage pathfinder[20]	This will build on the 2018-19 deliverables to progress the consideration of broader options to meet transmission system needs. This focuses on high voltage system needs, seeking solutions from transmission and distribution network owners in addition to market based solutions. We will further develop this project following on from the initial RFI, determining whether there is value to run a commercial tender and, where relevant conducting post tender evaluation through NOA based criteria and assessment to determine the best combination of asset and commercial solutions for meeting the regional high voltage needs. This will develop the necessary contract arrangements to facilitate participation by new and existing providers.	Decision to tender market solutions: Q1 2019-20 Project recommendations: Q3 2019-20
Pennines Voltage pathfinder	We will continue the high voltage project in the Pennine region to also consider market based solutions, include commercial solutions and further develop the necessary funding mechanisms to facilitate the participation of DNO solutions.	Run RFI and then decision to tender market solutions: Q1 2019-20 Project recommendations: Q3 2019-20
Constraint Management Pathfinder	The aim of this project will be to provide a commercial product based around constraint management.	Technical and economic analysis concluded in Q2 2019-20.

[20] We are currently no longer planning to issue a RFI for longer term reactive requirements in the South Wales region. This follows on from a recent evaluation of current system needs and priorities. We will continue with our pathfinding projects for high voltage requirements in the Mersey and Pennine regions and our stability pathfinder project in Scotland. Later this year we will be assessing future voltage requirements across the network, the results of which will be communicated early next year.

Deliverable	Description	Delivery Date
	We will analyse the impact of constraint services in an attempt to alleviate network congestion, reduce balancing costs, and deliver greater value to the Great Britain consumers as the electricity network evolves.	Stakeholder engagement &, commercial aspects completed by Q1 2020-21.

Building on our 2018-19 Forward Plan

We will expand our 2018-19 work to include market based solutions, looking to secure solutions to needs through requests for information through to potential tenders. At this point we will establish the value of these pathfinders and the ability of the market to compete with assets for a particular need. We will be making a final recommendation of the solution(s) to progress to implementation in the areas we consider. The work conducted in 2018-19 focused on the development of processes and learnings with the initial findings considering only asset based solutions. In 2019-21, we will expand the range of solutions to also include market options. We will implement the learnings from the work done in conducting the voltage need identification process for the first time and document this in the NOA methodology.

Study tools

Our study tools sit at the heart of our capability to model the transmission network and its behaviour. The generation and demand elements of that model are uncertain in the future meaning we have outcomes that are very uncertain. Historically we have studied the winter peak demand period with an intact system and credible conditions over the whole year. By using enhanced study tools combined with a probabilistic approach we will assess the year-round transmission network needs. This is a completely new way of modelling and interpreting results, a step-change in one of our core capabilities.

Consumer benefit outcome

Please see case study 13 in appendix C

A probabilistic approach will help us enhance our analysis beyond our current approach to boundaries providing greater insight on the likelihood of specific events occurring. This will enable us to focus analysis on the correct boundaries and scenarios, i.e. those that have resulted in high operational costs. This means that appropriate solutions can be evaluated to reduce the operational spend, creating greater benefit for consumers. In future, it could help improve the value that the *Electricity Ten Year Statement (ETYS)* and *NOA* drive for consumers by ensuring the right balance between operational and network solutions. In some cases, this could mean an increase or decrease in the amount of network capacity recommended when compared to our historic analysis approach, ensuring better outcomes for consumers.

We will continue work on our new voltage needs identification tools and processes to help assess in areas where local voltage issues could arise in future. Following screening of the issues we will look at priority regions in more detail and apply the NOA approach of comparing network and non-network solutions to regional voltage challenges.

Deliverable	Description	Delivery Date
Voltage needs identification tools/ processes	To enable a systematic approach to identifying snapshots for further investigation through detailed power system studies. The need for this process is driven by the increase in embedded renewable generation, giving rise to costly regional high voltage challenges.	Q1 2019-20

Deliverable	Description	Delivery Date
	Document and test voltage needs identification tools / processes for inclusion in the NOA. methodology. Identify up to three areas for further evaluation.	Q4 2020-21
	Continuous improvement of the tools & processes.	Ongoing
Thermal probabilistic assessment tool / process	Development of a thermal probabilistic assessment tool / process to allow greater consideration of year-round conditions. This tool / process can be used to identify the most relevant system boundaries and provide a better estimation of the transfer capability which reflects year-round operation.	Proof of Concept: Q2 2019-20 Initial boundary capability results available: Q3 2019-20

NOA: Enhanced communication

Consumer benefit outcomes

Please see case study 11 & 13 in appendix C.

We believe a key aspect of broadening the *NOA* is by increasing the number and type of participants, this will be driven by the quality and relevance of the information and data that we can provide. In considering a broader set of system needs and seeking solutions from a wider range of participants, we need to ensure that we can communicate effectively. Our network planning publications and requirements are tailored to their requirements of our current stakeholders who have a high technical understanding. In engaging a wider audience, we need to be able to set out our requirements and recommendations in a way that they can be easily interpreted and appropriate solutions developed to meet the relevant system needs. Through our *ETYS* and *NOA* publications and continued stakeholder engagement, we plan to evolve how we communicate system needs to facilitate greater stakeholder participation creating improved competition.

We continuously seek stakeholder feedback on our publications and are utilising existing industry forums to increase the awareness of our network planning documents and processes. We will continue with this in addition to looking to make modifications to our publications.

Deliverable	Description	Delivery Date
Improve accessibility of the ETYS and NOA publications	We will enhance the information that is provided on system needs to allow a wider audience to better understand needs and propose solutions to meet them and continue to engage with stakeholders on the development of capabilities and implementation of the *Network Development Roadmap*.	Ongoing
	Publication of needs to the market through RFI packs, which are supported by webinars.	Q1 2019-20
	Enhancements to information in *ETYS*, to include requirements for a wider set of system needs and more detail on existing system needs.	Q3 2019-20

Deliverable	Description	Delivery Date
	Provide regular updates to stakeholders on the progress of pathfinding projects and continue engagement with impacted stakeholders through mechanisms such as the ENA Open Networks project.	Ongoing

Building on our 2018-19 Forward Plan

Our *Network Development Roadmap* set out a three year plan to outlining how we would develop our network planning process. As part of this we stated how we would develop our tools. The probabilistic modelling tool has been developed to date to show the potential benefits of using such techniques. The tool developed was a beta (development) model and work is now being undertaken to develop a tool that can be tested and then integrated into our planning processes to assist in decision making. We are continuing to develop the work started on establishing year round voltage needs and we will look to continue to secure options to meet those needs from participants who wish to be involved. We will do this by incorporating distribution, transmission and non-network options.

Whole system data exchange

Consumer benefit outcome

Please see case study 10 in appendix C.

Our current activities to ensure coordination across system boundaries to deliver efficient network planning are set out in the Grid Code Planning Code. They revolve around the exchange of data between network companies to assess the security and safety of the transmission system at the interface with Network Operators. They do this for both operational and investment planning purposes.

The 'Statement of Works' process requires the DNO to inform us of new connections in their network to allow us to assess impacts on the transmission network. The existing process has been in place for a long time and was not designed to accommodate the volume of applications that DNOs have seen in recent years.

A newly developed data exchange approach provides DNOs visibility of the volume of capacity available at individual Grid Supply Points up to a set limit and greater transparency enabling them to contract with embedded customers more quickly without individual applications to us. By removing barriers to connection with the distribution network the new process allows DER to participate in markets much earlier than otherwise possible enhancing liquidity in energy and services markets.

This approach also saves the connecting customer £10k to £15k and can remove as much as 9 months from the connection offer process. Connection dates would have been offered much later than the customer had requested, connect and manage enabled these delays to be mitigated by allowing connection ahead of reinforcement build recognising that constraint actions may be required.

Deliverable	Description	Delivery Date
Extended roll out of enhanced whole system data exchange	The existing Week 24 data exchange process is in place to ensure that system modelling information of DNO networks is up to date to allow us and TOs to model the whole network accurately. Recently we have developed the Appendix G process which allows us to manage the connection of DER more quickly by releasing available capacity at Grid	Q2 2019-20

Deliverable	Description	Delivery Date
	Supply Points to allow DNOs to offer connections. This process requires data to be updated more frequently providing a more accurate view of the distribution networks. We will review the Week 24 process and the Appendix G requirements to determine whether a revised approach to data exchange can be adopted.	
Commercial flexibility around operational connections	In some congested areas of the transmission network, customers have connection agreements that require them to reduce their generation output under specific outage conditions. These conditions exist where transmission reinforcements have not been completed or where it is uneconomic to develop new infrastructure. The assessment of the network and the situations where restrictions exist is sensitive to generation contracted background and operating conditions on the system. By working with TOs, we will develop a process for identifying opportunities to more flexibly operate the network to prevent service disruptions where possible. This could be achieved through more targeted use of enhanced transmission equipment ratings or development of local operating procedures that can be introduced for specific conditions.	Q1 2019-20

Whole system operability

Increased volumes of distributed generation on parts of the network are causing operational challenges that lead to additional costs of operating the network including constraint payments to generators operating on a part of the network that cannot accommodate their output. Challenges such as high voltage and RoCoF require us to work with DNOs more closely than ever before to identify new ways of operating the whole electricity system to reduce costs.

Consumer benefit outcomes

Please see case study 8 in appendix C.

Deliverable	Description	Delivery Date
Roll out of Loss of Mains Protection setting	We have proactively identified an opportunity to reduce costs of operating the system through changing protection settings on distributed generators and have trialled different approaches in a number of areas. Having learned from the successful vector shift change exercise, in 2019-21 we will engage other network operators to implement Loss of Mains changes more widely.	Commencing Q1 2019-20
Defining roles and responsibility for voltage management across the	Working with DNOs to optimise voltage on a whole system basis: • Short-term operational solutions	Q3 2019-20

transmission-distribution interface	• Transmission – distribution reactive power performance measures	
Inertia measurement	Implement a first of a kind system to measure system inertia in real-time and use it to optimise real-time operation, service procurement and network development.	Q1 2020-21

Deeper system access planning

Consumer benefit outcomes

Please see case studies 14 & 15 in appendix C.

Transmission owners require access to their equipment for a variety of purposes including maintenance, fault repair and modification. Work on these assets can mean costs for the TO, potential disruption for connected customers and operational costs which are ultimately borne by the consumer.

We believe that taking a deeper whole system view of these costs and impacts will result in system access planning arrangements that work for customers and ensure value is delivered for consumer.

This approach will have the greatest benefit in the delivery of major infrastructure projects, potentially including those across the transmission – distribution interface. Such projects may take years to deliver and require extensive outage programmes. We believe greater value can be released through enhancing our ways of working with both TOs as well as DNOs and other connected parties

Deliverable	Description	Delivery Date
Deeper access co-ordination of 1-2 major infrastructure projects to commence in the RIIO-T1 period	Roll out the process we have developed to identify and deliver customer value opportunities in Scotland from system access planning. We will have a Metric 12 to measure the value we deliver from this in Scotland, and develop the metric to cover the England and Wales TO as we move into legal separation.	Q3 2019-20
	Identification of 1-2 major infrastructure projects to commence in the RIIO-T1 period that could deliver value through deeper access planning. Develop enhanced ways of working with network organisations and other connected parties to better facilitate efficient project delivery. This to include consideration of the costs of system operation, customer impacts, as well as project delivery costs.	Q4 2020-21

Enhanced customer experience

Consumer benefit outcomes

Improvements to our systems and processes for managing customer connections and access to the transmission network will help our customers to be more efficient as they participate in energy markets or develop network assets. Such efficiencies will be passed on to the end consumer through reduced energy and network development costs.

Deliverable	Description	Delivery Date
TOGA replacement	Following stakeholder engagement to understand user requirements, we will be developing the TOGA system replacement. This is the tool that customers and TOs use to request system access.	Q4 2019-20
Customer journey mapping – outage planning	We will work with teams across National Grid Electricity Transmission (NGET) to improve the experience for networks and market participants relating to outage management. We will develop concepts to address the pain points in the existing process. This includes ideas on how we can do things differently to provide a better service as well as considering the activities that would need to be in place.	Q1 2019-20
Connections customer portal	Detailed scoping of tool to provide a visual and live update for customers on the progress of their connection application.	TBC in our monthly reporting

How we will measure performance in 2019-20

Metric 10 – Whole system, unlocking cross-boundary solutions

This performance metric is measuring the outcomes of the following deliverables:

- Ongoing Regional Development Programmes
- Development of a Proactive RDP Identification Process

Consumer benefit

The deliverables under these roles seek to benefit consumers in the following ways:

1. Saving infrastructure costs by avoiding or deferring the need to build additional assets to cope with further DER connections; and
2. Reducing balancing costs by promoting competition in the provision of balancing services, so that downward pressure can be brought to bear on prices.

RDPs act as enablers for DER to connect to networks and participate in markets, reducing the costs of developing and operating the electricity system in the future. Whilst it is very hard to quantify potential future savings in operational costs, we can consider the benefits of flexible connection capacity in terms of avoided asset spend.

Context

The RDP regions in South-East England, South-West England and South-West Scotland are characterised by limitations in transmission network capacity that, under normal circumstances, would mean long connection lead-times whilst expensive asset reinforcement was undertaken.

South-East England: The South-East coast network, with its multiple interconnectors to Continental Europe and large transmission-connected generators, meant that transmission capacity issues were beginning to impact on customer connection dates. DER developers rely on the ability to be able to connect to the network quickly, so this was perceived as a potential barrier to the growth of renewables in the area.

South-West England: Available transmission and distribution network capacity issues could potentially limit the volume of DER that will be able to connect in the South-West of England. Renewable resources, such as solar and wind, are favourable in the region and it is expected to play a major part in meeting the future governmental green energy targets, so it is important that connections can be facilitated in a timely manner.

South-West Scotland: This sparsely-populated region of southern Scotland has a large potential for growth of renewable energy sources. The predominant renewable resource in the area is wind, and it is anticipated that this already congested area will attract further development, with connection requests expected to grow significantly over the coming years.

During 2017-18, we collaborated with UKPN and Western Power Distribution (WPD) to define ways that would enable, DER to continue to connect in these constrained areas. We also worked closely with Scottish Power Energy Networks (SPEN) on a way to tackle the challenges of the South-West Scotland network.

The deliverables captured in our 2018-19 Forward Plan represented the start of the delivery phase of work to enable these connections, and to give us access to a wider range of constraint management tools, which support the ongoing efficient management of transmission network issues, supporting system security and potentially driving down balancing costs. The nature of this work has meant that delivery continues in the period covered by this Forward Plan, and the metric below seeks to quantify the value of this work to consumers.

Metric

Assessment of the performance will be on an ex-post basis, using:

1. The level of DER MW that have signed contracts to connect to the distribution networks; and
2. A narrative setting out how we have established the conditions under which these new connections have been made possible.

The baseline date for each region is that when the conditions to facilitate further connections were established; as follows:

Region	Date
South-East England	1st April 2019
South-West England	1st April 2019

This metric is designed as a measure of the effectiveness of the systems, contracts and processes we implement in 2019-21, as measured by new capacity contracted at distribution level. We are unlocking addition generation connections through the new ways of working we are putting in place. Without our new ways of working, the generation wishing to connect would have to wait on network re-enforcement before being able to connect, which could be years in the future. We have put in place new commercial arrangements, between three parties (ESO, DNO, generator), not a typical two-way arrangement. We also have put technical arrangements in place to manage power-flow congestion across network boundaries.

Metric 11 – System access management

This performance metric is measuring the outcomes of the following deliverables:

- Deeper outage planning
- Customer journey mapping – outage planning
- Transmission Outage and Generator Availability (TOGA) replacement

Consumer benefit

Reducing unnecessary network and balancing costs by improving the system access request planning process.

Context

We direct the flow of electricity over the transmission system in real time and the three TOs and OFTOs own the assets through which the electricity is transferred. To ensure that these assets are maintained, the TOs need to ask us for access to their assets. When the system access requests are formally submitted, we perform due diligence on these requests and, if secure and economic, they are accepted into the master outage plan.

When a system access request has been accepted into the plan, customers will have acted on the assumption that it will go ahead. This includes TOs, DNOs and generators who could have, for example, incurred costs hiring specialist contractors or equipment. Sometimes these requests are delayed or even cancelled within day for a variety of reasons from unforeseeable weather conditions to faults on the system to planning process failures. These cancellations can lead to higher network costs; the estimated delay costs to the TOs are between £5,000 and £15,000 a day.

We proactively work with all stakeholders to attempt to provide efficient access to the system when they want it. Ideally, we would like significant notice of system access requests, but a lot of stakeholders want more flexibility than this. With flexibility and late notice access comes additional risk of failing to release an outage. We do not want to restrict flexibility, and therefore this metric keeps us focused on delivering our processes well in a fluid environment. As a result, outage plans are now more active than they used to be, as there is an interaction between outages for maintenance and network build, and new connections.

Metric

This metric looks to drive down the number of planned outages that are delayed by more than an hour or cancelled by us in the control phase due to process failure, investigating the reason for cancellations and putting in place changes into the process where appropriate to prevent a repeat. Sometimes we should cancel system access requests that have been accepted into the plan because these are no longer securable or the costs are too high. We will continue to cancel system access requests where needed, but this number should be as low as practical to avoid costs for external stakeholders and our costs in re-planning these requests. The tension between these two aspects is dynamic and so we will work to reduce the number of control phase cancellations out of every 1,000 system access requests.

This measure is a count of the number of outages out of every 1,000 delayed by more than an hour or cancelled within day.

Performance benchmarks

Current performance: 5.25 delays more than an hour or cancellations within day per 1,000 outages accepted into the master outage plan.

Exceeds benchmark: Less than or equal to 5 per 1,000 outages

In line with benchmark: Between 5 and 8 per 1,000 outages

Below with benchmark: More than 8 per 1,000 outages

Metric 12 – Customer value opportunities

This performance metric is measuring the outcomes of the following deliverables:

- Deeper outage planning
- Customer journey mapping – outage planning
- Transmission Outage and Generator Availability (TOGA) replacement

Consumer benefit

We create customer value opportunities for customers and the whole system by going over and above our network access planning policies and procedures. When we do, this has a positive impact on our CSAT (Customer Satisfaction Survey) scores and results in savings in BSUoS cost which should lead to lower bills for the end consumer.

Context

The TO need access to their assets to upgrade, fix and maintain the equipment. They request this access from us and we then need to plan and coordinate this access. As part of the network access process, we have been creating and capturing added value for the customers and stakeholders for some time now by:

- Coordinating with the TO to calculate the cost benefit analysis of outage requests in the NAP paper,
- Minimising the duration of outages requested by the TO,
- Moving outages in coordination with the TO using the System Operator-Transmission Owner Code Procedures (STCP) 11-4,
- Accepting and planning additional high value outages received within year,
- Optimising outage placement including nesting of outages,

- Proposing alternative solutions to the TO like temporary connections for generation affected by long outages,
- Changing outages within year using STCP 11-3,
- Reassessing system capacity.

This work minimises the impact of outages on energy flow and reduces the length of time generation is unable to export power into the network.

Metric

The customer value opportunities metric captures the BSUoS and customer savings from the above-mentioned activities that we create and aims to measure the performance of our network access planning process in transmission outage optimisation by capturing direct and indirect savings to the end consumer.

The metric targets are split into direct and indirect savings to the end consumer. The direct savings to the end consumer are those that are tied to BSUoS cost savings while the indirect savings are those that positively affect the customers (generators/DNO) and ultimately give benefit to the end consumer.

The target values for Scotland Outage Planning are set from historic measurements and performance. At this moment, we do not have historical data for North and South Outage Planning teams who cover England and Wales. Through the year post legal separation from the NG TO we will develop the metric to cover England and Wales.

Performance benchmarks

Network Access Planning Targets	Direct savings to end consumer per year	Customer (Generator/DNO) savings/ indirect savings to end consumer per year
Outage Planning – Scotland	55,000 MWh	110,000 MWh

Direct savings to end consumer:

Exceeds benchmark: Greater than 55,000 MWh

In line with benchmark: Between 50,000 MWh and 55,000 MWh

Below with benchmark: Less than 50,000 MWh

Customer savings and indirect savings to end consumer:

Exceeds benchmark: Greater than 110,000 MWh

In line with benchmark: Between 100,000 MWh and 110,000 MWh

Below with benchmark: Less than 100,000 MWh

Metric 13 – Connections agreement management

This performance metric focuses on our balancing cost management metric.

Consumer benefit

Reducing balancing costs by ensuring that we have access to appropriate commercial options following changes to the transmission network, to maintain its operation of the transmission system.

Context

The Great Britain transmission system is constantly under change as the three TOs and Offshore Transmission Owners (OFTOs) build new assets. All generation that needs to be connected to the transmission system requires a contract with us. After the TOs make changes to the transmission system, they inform us of these changes. We need to ensure that the relevant contracts for the affected generators are then updated to reflect this change.

Some agreements permit us to curtail generation under certain circumstances at no cost but if an agreement is not up to date and the generation requires curtailment, we may need to instruct this through a Bid Offer Acceptance (BOA). Ensuring that connections agreements are up to date to reflect changes to the transmission network gives us more options to ensure the system can be run safely and securely and potentially saves BSUoS cost when we would need to pay to curtail generation.

Updating connection agreements requires collaboration between us and the relevant TO and then a three-month period to get the updated agreement signed off by the customer. We cannot control all aspects of the performance as it requires interaction between us, the TO and the customer, so targets reflect this.

Metric

This metric will measure how long it takes from the point of notification for these agreements to be updated. This metric drives efficient and effective management of existing connections contracts by measuring the percentage of contracts up to date within nine months.

Performance benchmarks

Current performance: = 86%.

Exceeds benchmark: >90% of agreements to be updated within nine months of notification.

In line with benchmark: 80-90% of agreements to be updated within nine months of notification.

Below benchmark: < 80% of agreements to be updated within nine months of notification.

Metric 14 – Right first time connection offers

This performance metric is measuring the outcomes of the following deliverables:

- Enhanced customer experience: Connections customer portal

Consumer benefit

Ensuring Connection offers sent to customers are 100% correct minimises re-work and facilitates timely and efficient connection to the network.

Context

Historically customers connecting to our networks have been involved in the industry for many years and have experience in developing new projects and the connection application process. With the increase in renewable generation and smaller sized projects connecting to our networks, the customers we now work with have much less knowledge of the network and the processes for connection. This provides us with an opportunity to provide excellent customer service and to use the skills and knowledge we have of the industry to help new entrants come into the market. This requires us to work much more closely with those customers who are new to the industry to ensure that the solution we develop is right for their business. This metric measures how well we deal with this challenge by quantifying how often we get it right first time.

Metric

To measure the quality of a customer's connection offer we will use a right first time measure. The right first time metric will report all connection offers signed within a calendar month and identify if a 'reoffer' has been made (i.e. the offer was not right first time and needed rework) and what the root cause for the rework was. Any reoffers directly attributable to the ESO will impact the performance of the metric. Any rework driven by a TO or driven by a customer change to requirements during the process will be excluded from the metric performance but reported for information only.

Performance benchmarks

Current performance: = 94%.

Exceeds benchmark: >95% of offers right first time.

In line with benchmark: 95% of offers right first time.

Below benchmark: < 95% of offers right first time.

Metric 15 – NOA consumer benefit

This performance metric is measuring the outcomes of the following deliverables:

- Pathfinding projects
- Study tools
- NOA: enhanced communication

Consumer benefit

Reducing network and balancing costs by pursuing a full range of good quality options to be included into a Network Options Assessment. This includes the annual NOA process in addition to cost benefit assessments conducted on projects outside of the annual process.

Consumer benefit outcomes

Please see case studies 11 & 13 in appendix C.

Context

We carry out the NOA annually to recommend to the three TOs in Great Britain which reinforcement projects should proceed to meet the future needs for the bulk transfer of electricity over the electricity system, and which to delay. The NOA methodology, approved annually by Ofgem, uses 'single year least worst regret analysis to quantify the risk each course of action poses. Selecting the strategy with the lowest maximum regret leaves the consumer exposed to the lowest risk.

To continue to drive consumer value and manage future uncertainty, we are expanding the system needs for which a network option assessment approach is used to determine the best solution. The first step is to implement a NOA style approach to determine the most efficient solutions to high voltage and stability needs. We are seeking solutions to these needs from a broader set of solution providers including DNOs and market participants in addition to TOs. Greater participation from stakeholders maximises value for consumers.

The requirement to consider a broad set of solutions from a broader audience to any system need will drive us to work with all parties to devise good quality options, including reduced build and commercial solutions where these are appropriate. These may be a cost-effective solution for the long-term or a method to save constraint cost in the short term while larger network assets are built.

Metric

There is significant value to the consumer in the ESO undertaking the NOA process. Running the NOA process is a business as usual deliverable, but the extent to which we seeks alternative solutions to TO led solutions exceeds baseline activities. The value the NOA delivers helps set the context of the significant value that we can add in broadening the scope of solutions to include options from a wider audience.

We propose to measure the value of undertaking the NOA delivers by analysing the increase in constraint costs which we would expect to incur if none of the options in the optimal path were proceeded for one year. This will highlight the importance of delivering both the ESO determined optimal solution at the correct time according to the ESO analysis. We do not believe it is appropriate to have a target against this as the value is very dependent on the level of network investment which is required. This can vary significantly over time and is not something which the ESO has direct control over.

We propose targets around elements over which the ESO has control. This is in the options which are put into the NOA process and are recommended as part of the optimal paths. We propose a metric measuring the options which are submitted as part of the NOA process, categorising options into the following categories:

- ESO Exclusive options **–** These are options which are exclusively developed or sought by the ESO. These will include operational options, commercial services and options from other interested parties, such as DNOs.
- ESO Collaborative options **–** These are options which the ESO has collaborated with the TO on. This could be in influencing the design or location of a particular option, influencing build order of options or working more collaboratively with a TO to propose new technology solutions. This can include both reduced build and asset build solutions as there is value in the SO helping unlock variations to asset build options if it can result in consumer benefits.
- TO Exclusive options **–** These are options which are submitted by the TOs and which have had no direct input from the ESO. These will include a mix of both reduced build and asset build options.

We believe it is appropriate for the ESO to have targets around the options which appear in the ESO Exclusive and ESO Collaborative options category. We propose this to be both a numerical target and value. As the number of options and consumer value will vary year on year influenced by the level of reinforcement required on the network we propose for these metrics to be a percentage of the options in the optimal path. We propose to apply this metric to the NOA published annually every January and also the pathfinding projects.

The above metric describes how we value the NOA, but we also conduct further analyses which deliver significant consumer benefit which we do not report externally. To help set the context and the value of the work we do we also propose to report on the consumer value we deliver from undertaking Strategic Wider Works process (SWW), Connection and Infrastructure Options Note (CION) and small scale CBAs[21]. SWW and CION form part of our baseline as they are part of our licence obligations. The small-scale CBAs however are more ad-hoc requests, which are exceeding our baseline obligations. As such we propose purely reporting against SWW and CION, also due to the fact we have no control on the number of these projects which are conducted each year. For the small scale CBAs, we do propose a target in terms of the number we do on an annual basis. The value delivered could vary considerably and so this would just be reported.

Performance benchmarks

Where we are exceeding baseline is where the percentage value of the options we are involved in exceeds the percentage number of options in the optimal path. This shows that as ESO we are driving value through creating and influencing options to best meet system needs. The value created through conducting small scale CBAs is exceeding baseline as this is not a licence obligation. We identify circumstances where alternative options could be beneficial and also respond to TO requests to support evaluation of different options. This additional activity has the potential to deliver significant consumer benefit.

NOA consumer benefit

Consumer benefit: Constraint costs which would otherwise be incurred if all optimal path options were delayed by 1 year.

[21] A small-scale CBA covers any cost benefit analysis which does not form part of a SWW or CION CBA. This can include assessment of build programmes delivery, connection designs, etc.

Exceeding baseline: The % of ESO exclusive and ESO collaborative options is >12% of the total number of options in the optimal path or the value is >4% of the overall consumer benefit.

Meeting baseline: The % of ESO exclusive and ESO collaborative options is between 10% and 12% of the total number of options in the optimal paths and the value is between 3% and 4% of the overall consumer benefit.

Below baseline: The % of ESO exclusive and ESO collaborative options is below 10% of the total number of options and the value is below 3% of the overall consumer value.

This is applicable to the annual NOA publication and all pathfinding projects.

These targets were set on the basis of our performance in 2018/19, where the number of options we were involved in was 12%, delivering 4% of the value.

Cost Benefit Analysis

Consumer benefit from SWW: Report the consumer benefit for the preferred option against the next best option.

Consumer benefit from CION: Report the consumer benefit for the offered connection location against the customer desired connection location.

Consumer benefit from Ad-hoc CBA

Consumer benefit: Report consumer benefit from all small-scale CBAs conducted.

Target: Conduct 3 small scale CBAs per year.

Exceeding benchmark: The number of ad-hoc CBAs conducted is above target.

Meeting benchmark: The number of ad-hoc CBAs conducted is on target.

Below benchmark: The number of ad-hoc CBAs conducted is below target.

These targets were set on the basis that on average, we conduct 3 small scale CBAs per year.

Metric 16 – NOA: Enhancing Communication

This performance metric is measuring the outcomes of the following deliverables:

- Pathfinding projects
- Study tools
- NOA: enhanced communication

Consumer benefit

Providing sufficient information to parties interested in submitting options to meet system needs will allow them to effectively develop solutions to be assessed against traditional options. In providing the right information in suitable timeframes we can facilitate more options into any options assessment process.

Context

As set out in our Network Development Roadmap we plan to evolve our ETYS and NOA documents over the coming years to make information more accessible. Expanding the NOA to a wider audience will mean that we need to ensure our requirements can be understood by a different audience who do not have access to supplementary information from code obligations. We need to ensure that all parties have access to sufficient information to be able to effectively develop their solutions to identified system needs.

We continually strive to improve our network planning publications to meet our stakeholder needs and ask for feedback on all documents published. To further understand whether our documents meet our stakeholder needs we will be enhancing our publication surveys to understand how satisfied stakeholders are with our current documents and the information provided.

Metric

This metric will comprise online surveys available for all of our Network Planning publications. This includes the NOA methodology, results of any pathfinding projects, the ETYS and the NOA. Our current surveys will be adapted to seek scores for stakeholder satisfaction on the document overall and the quality and relevance of the information contained within them. For the first year, this metric will be used to determine a baseline level of satisfaction. We will then use this feedback to set targets for the following year.

Performance benchmarks

Exceeding benchmark: High scores and positive stakeholder feedback on the documents and changes we are making to them.

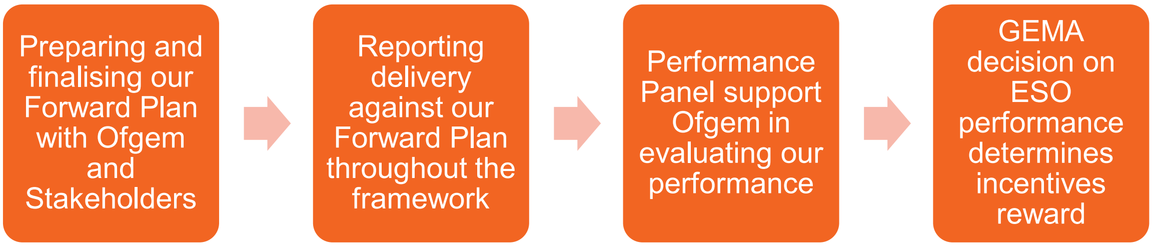
Meeting benchmark: Meets licence obligations. Average stakeholder feedback with clear areas for improvement.

A
Incentives Framework

How does the Incentives Framework work?

Following engagement with stakeholders on the new Incentives Framework, we want to provide greater clarity to our stakeholders on purpose and importance of the Forward Plan and how our performance against this plan results in an incentives award. Throughout 2018-19, we have continuously engaged with Ofgem on the objectives and detailed process of this Incentives Framework. We welcome the changes to the roles and principles and ESO Reporting and Incentives Arrangements Guidance that have been introduced by Ofgem from April 2019[22].

Figure 5 – Incentives Framework process steps



Preparing and finalising our Forward Plan provides our delivery commitments to stakeholders and consumers for the delivery year. The plan articulates how our long-term vision, informed by our commitment to deliver most benefit for consumers, shapes our activities as we work towards this vision; alongside this, our performance metrics allowing us to share how we are tracking delivery against our plan. To prepare our draft Forward Plan, we undertake a rigorous business planning process internally, considering the feedback we have already received from stakeholders to shape our delivery plan and how we can best deliver benefits for consumers. We then undertake a formal consultation process with stakeholders and Ofgem on our draft Forward Plan to allow you to comment and challenge our plan to ensure that we are targeting the activities that deliver the most benefit. Using this feedback, we prepare our final Forward Plan published before the start of the delivery year. To help you understand how we have used and responded to your feedback, our Forward Plan includes appendix D that acts as a ‘you said, we did’ summarising the changes we have made.

As of March 2019, this plan sets out known commitments for the next two years. Against the backdrop of the transition to a decentralised, low-carbon system, we will continue to review our plans, ensuring that we are delivering most value for consumers. New opportunities may arise for us to take actions to unlock consumer benefits that were not identified within this Forward Plan and/or we may need to adapt our plans based on changes within the industry. Throughout the year, we will share these updates with stakeholders through our reporting.

Who is on the Performance Panel?

Ofgem chair: Cathryn Scott, Director Wholesale Markets.

Consumer representative: Citizens Advice (rep: Richard Hall).

Trade associations: The Association of Decentralised Energy (rep: Chris Kimmett), The Energy Networks Association (rep: Stephanie Anderson) and Energy UK (rep: Kyle Martin).

Independent experts: Professor Jon Stern, Ian Tait and Robert Hull

On the 1st May, Ofgem will share a Formal Opinion on our Forward Plan commenting on long-term strategy and vision, the level of ambition of the plan, specifically our deliverables and performance metrics. This is to help us, the Panel and stakeholders understand Ofgem’s view of our plan.

During the delivery year, we will report on our progress against our Forward Plan, providing you with a snapshot of how we have achieved planned outcomes and delivered benefits for consumers. We will provide awareness of any changes to our plans and additional commitments.

[22] https://www.ofgem.gov.uk/system/files/docs/2019/03/decision_letter_-_regulatory_and_incentives_framework_for_2019-20.pdf

Our reporting will be consolidated in a mid-year (October publication) and end of year report (May publication).

At the mid-year and end of year, we will meet with Ofgem and the Performance Panel to present our performance to inform their assessment of our performance at mid-year and end of year evaluation points. You are invited to help support this process, providing feedback on how we have performed and can provide any further representations on this evaluation before a final decision to the Gas and Electricity Markets Authority (GEMA).

GEMA will consider the Performance Panel's recommendations, as well as any other evidence received or collected, and decide on an appropriate reward or penalty (+/- £30m) by 31 July.

How is the award calculated?

As outlined in Ofgem's decision paper on the changes to the Incentives Framework, the evaluation weighting is different from 2019-20; each of our roles (with roles 3 and 4 combined) are equally weighed with a reward or penalty of +/-£10m totalling to +/-£30m overall. In assessing our performance, five evaluation criteria are used:

- Evidence of delivered benefits,
- Evidence of future benefits / progress against longer term initiatives,
- Stakeholder views,
- Plan delivery,
- Outturn performance metrics and justifications.

The five evaluation criteria are not equally weighed reflecting that some roles will driver longer term consumer benefit, particularly roles 3 and 4; thus, the level of evidence presented across the roles will reflect the scope of the roles. More detail on the performance evaluation can be found within the ESORI document[23].

How is the award recovered?

BSUoS recovers the cost of day-to-day operation of the transmission system. Generators and suppliers are liable for these charges, which are billed daily and calculated as an half-hourly £/MWh rate. It is a flat tariff applied proportionally according to the portfolio share of a user. It is made up of several components including award/receipts from NGESO Incentive Framework.

During the delivery year, using feedback from Ofgem and the Performance Panel, we estimate the level of incentive reward we expect to earn for evidencing the successful delivery of our plan and expected consumer benefits. This amount is recovered during the delivery year through our BSUoS process. Following the first year of the framework, we have engaged with Ofgem on a proposed change to our licence to remove the risk of any unforeseen deviations to the incentive recovery element of the charge. The proposal is that we will reconcile the difference between what we have recovered during the year and the final Authority decision which occurs after the financial year has closed after the Authority decision has been made. This change will be discussed with industry through a consultation in Spring 2019.

For more details please see the charging section of our website: https://www.nationalgrideso.com/charging or contact BSUoS.Queries@nationalgrideso.com

[23] https://www.ofgem.gov.uk/system/files/docs/2019/03/esori_guidance_document_2019-20.pdf

Innovation funding

RIIO (Revenue=Incentives+Innovation+Outputs) is performance-based framework used by Ofgem to set the price controls.

To support the transition to a decentralised, decarbonised and digitised energy landscape, network innovation provides essential backing to support projects and programmes. This accelerates the transition delivering additional benefit for consumers and develops crucial technical knowledge and expertise that can be shared across industry. Typically, these projects are to research, develop and demonstrate new technologies, and/or operating and commercial arrangements and carry a greater level of uncertainty and risk.

Outlined in the table below are the projects within the Forward Plan we have presented that have a level of innovation funding. We have included these activities in our plan as we are undertaking activities that go beyond those funded by NIA[24] or NIC[25]. We actively work to take the learnings from these projects to embed the technical knowledge and expertise into our wider range of activities; looking at how we can further accelerate the change to the energy landscape that brings the most benefit for consumers.

Role	Deliverable	NIA or NIC Funding
Manage system balance and operability	FES (EV charging profiles)	NIA
Facilitating competitive markets	Auction Trial[26]	NIA
	Power Potential	NIC
	Alternative approaches to restoration (Blackstart)	NIC
	Deliver innovation projects to unlock demand flexibility (Water DSR and Residential Response)	NIA

[24] https://www.ofgem.gov.uk/network-regulation-riio-model/network-innovation/electricity-network-innovation-allowance

[25] https://www.ofgem.gov.uk/network-regulation-riio-model/current-network-price-controls-riio-1/network-innovation/electricity-network-innovation-competition

[26] The creation of the algorithm for the frequency response auction trial, along with the portal that providers will use to submit bids, is funded through the Network Innovation Allowance. This does not cover the internal systems and processes that we require to ensure that the auction works with our ENCC and settlement systems.

B

Deliverables List

Full deliverables list

This table summarises the deliverables listed within the role delivery sections. We recognise the overlaps between our four roles and that our deliverables can contribute to more than one; within the table we recognise where a deliverable is a primary contributor to a role using the following icon ☑ and where a deliverable contributes to the success of other principles we using the following icon ✓. As we report progress against our plan, we will report all deliverables against their primary role only providing detail on how they have contributed to all appropriate role.

Deliverable	Delivery date	Meeting or exceeding baseline expectations	Role		
			1	2	3&4
Uninterrupted, safe, secure system operation		Meeting			
System security metrics	Q1 – Q4 2019-20		☑	✓	✓
Procurement Guidelines Process	Q4 2019-20		☑	✓	✓
Transparency of data used by our ENCC in our close-to-real-time decision making		Exceeding			
Publication of operational planning data	Commencing Q3 2019-20		☑	✓	✓
Future of the ENCC	Ongoing		☑	✓	✓
Operational insights		Exceeding			
Insight on balancing decisions taken	Q3 2019-20		☑	✓	✓
Insight on constraint boundaries	Q2 2019-20		☑	✓	✓
Electricity Operational Forum and stakeholder engagement		Meeting			
Electricity Operational Forum	Q2, Q3 and Q4 2019-20 and 2020-21.		☑	✓	✓
ENCC visit days	Q1-Q4 2019-20 and 2020-21.		☑	✓	✓
Addressing operational issues		Exceeding			
Roll out of Loss of Mains protection settings	Q4 2019-20		☑		✓
Upgrade of information systems					
Frequency and time equipment FATE-3	Q4 2019-20	Meeting	☑	✓	✓
ASDP	Q2 2019-20		☑	✓	✓
Significant upgrading of IT systems to prepare for European Network Codes	Q3 2019-20		☑	✓	✓
Pi gateway refresh	Q4 2019-20		☑	✓	✓

Deliverable	Delivery date	Meeting or exceeding baseline expectations	Role		
			1	2	3&4
Interconnector programmes	Ongoing		☑	✓	✓
Power Available	Q3 2020-21		☑	✓	✓
Balancing System infrastructure upgrade			☑	✓	✓
EFS	Q3 2020-21	Exceeding	☑	✓	✓
Control capability development	Q4 2021		☑	✓	✓
Insights documents					
Summer Outlook	Q1 2019-20 & 2020-21	Meeting	☑	✓	✓
FES	Q2 2019-20 & 2020-21		☑	✓	✓
Winter Outlook and Winter Review and consultation	Q3 2019-20 & 2020-21		☑	✓	✓
Operability Strategy Report	Q1 and Q3 2019-20 & 2020-21	Exceeding	☑	✓	✓
Forecasting					
Publish Forecasting Strategy Project roadmap	Q1 2019-20	Meeting	☑		
Publish half-hourly PV forecasts to market, 24 times a day	Q1 2019-20	Exceeding	☑		
Publish four additional wind forecasts to the market	Q2 2019-20		☑		
Publish an additional Day-Ahead demand update at 12:00pm every day	Q2 2019-20		☑		
Make energy forecasts more accessible via a dedicated website and APIs	Q3 2019-20		☑		
Information access					
Data explorer page on website	Q1 2019-20	Meeting	☑	✓	
New data portal	Q3 2019-20	Exceeding	☑	✓	
Product Roadmaps for Response and Reserve implementation		Exceeding			
Rollout of full functionality in frequency response auction trial	Q3 2019-20		✓	☑	

Deliverable	Delivery date	Meeting or exceeding baseline expectations	Role		
			1	2	3&4
Report on development of new frequency response product suite	Q3 2019-20		✓	☑	
Report on auction trial	Q2 2021-21		✓	☑	
Market design for reformed reserve products	H1 2019-20		✓	☑	
Report on our plan for retaining specific products	Q1 2019-20		✓	☑	
Migration of non-BM STOR providers to ASDP	Q2-4 2019-20		✓	☑	
Implementation of Pan-European replacement reserve standard products	2019-21		✓	☑	
Product Roadmap for Reactive implementation					
Communicate reactive power requirements & historic spend	Q2 2019-20	Meeting	✓	☑	✓
Implement approach for efficient reactive power flows between networks	Q2 2020-21	Exceeding	✓	☑	✓
Work with industry to determine future role for reactive power and design more competitive reactive power services	Q4 2018-19 – Q2 2020-21		✓	☑	✓
Commence implementation plan to enable rollout new approach to competitive reactive power services	Q3 2020-21		✓	☑	✓
Power Potential trial with UKPN	Q2 – Q4 2019-20		✓	☑	✓
Review learning from Power Potential	Q4 2019-20	Meeting	✓	☑	✓
Product Roadmap for Restoration implementation		Exceeding			
Alternative Approaches to Restoration	2019-20		✓	☑	
Develop and evolve a market approach for the procurement of Black Start services	Q4 2019-20		✓	☑	
Power Responsive					

Deliverable	Delivery date	Meeting or exceeding baseline expectations	Role		
			1	2	3&4
Deliver innovation projects to unlock demand flexibility	Q1-Q4 2019-20	Exceeding	✓	☑	
Power Responsive Stakeholder Engagement	Q1 2019-20 – Q4 2020-21	Meeting	✓	☑	
Wider Access to Balancing Mechanism Roadmap implementation		Meeting			
Clearer accession requirements for BM participation and enable aggregated BMU participation in balancing services	Q1 2019-20		✓	☑	
Use better technology/systems to improve efficiency of installing communications with BM providers and optimising BMU dispatch	Delivery throughout 2019-20		✓	☑	
Support industry work on providing and delivering against Physical Notifications (ELEXON led) and also support on work on accurate settlement for behind the meter	Q3 2019-20		✓	☑	
Intermittent Generation					
Raise code modification to apply Power Available consistently across technical & commercial codes	Q1 2019-20	Meeting	✓	☑	
Publish Power Park Module signal best practice guide	Q2 2019-20		✓	☑	
Deliver Power Available integration phase 1	Q3 2019-20	Exceeding	✓	☑	
Publish wider strategy on flexibility from intermittent generation	Q4 2019-20		✓	☑	
Deliver Power Available integration phase 2a	Q4 2019-20		✓	☑	
Deliver Power Available integration phase 2b	Q3 2020-21		✓	☑	
Provider experience		Meeting			
Feedback approach	Q1 2019-20			☑	
Improved online resources	Q1 2019-20			☑	
Facilitating code change					

Deliverable	Delivery date	Meeting or exceeding baseline expectations	Role		
			1	2	3&4
Meeting calendar & transparency of workgroups	Q1 2019-20	Meeting		☑	
Governance process FAQs, improved guidance material and critical friend review	Q2 2019-20			☑	
Facilitation of pre-modification discussions	Q3 2019-20			☑	
Incorporation of all 14 CACoP Principles	Q3 2019-20			☑	
Engage all parties to understand information requirements for code modifications and provide executive summaries on modifications	Q1 2019-20			☑	
Code administrator website	Q3 2019-20			☑	
Historical timelines & horizon scanning: cross-code	Q2 2019-20			☑	
Raising potential impact of modifications	Q3 2019-20	Exceeding		☑	
Governance surgeries	Q2 2019-20			☑	
Horizon scanning: strategic	Q3 2019-20			☑	
Transform industry frameworks to enable decentralised, decarbonised and digitised energy markets					
Leadership in the successful transformation of electricity access and charging	Q1 2019-20	Exceeding		☑	
Leadership in the Energy Codes Review	Q1 2019-20	Meeting		☑	
Working for you on European matters	Q2 2019-20	Exceeding		☑	
Unlocking whole system network development opportunities	Q1 2019-20			☑	
Developing and driving targeted market improvements	Q1 2019-20			☑	
Facilitate electricity network charging reform through Charging Futures		Exceeding			
Transform the customer experience for network charging					

Deliverable	Delivery date	Meeting or exceeding baseline expectations	Role		
			1	2	3&4
Improve our ESO charging query processes	Q1 2019-20	Meeting	✓	☑	
Improve understanding of our onboarding processes and streamline to meet our customer needs	Q1 2019-20		✓	☑	
New data reports for BSUoS	Q1 2019-20	Exceeding	✓	☑	
Reform of website content in to a user-centric knowledge base	Q2 2019-20		✓	☑	
Publications and guidance of the impact of charging reform to our customers	Ongoing from Q2 2019-20		✓	☑	
Introduce new 'new entrant' e-learning on charging	Q4 2019-20		✓	☑	
Improve the digital customer experience for TNUoS, BSUoS and Connection Charging Data; including the introduction of a new NGESO billing system	Q1 – Q4 2020-21		✓	☑	
Establish a 'cross party' approach to onboarding, mapping out whole industry requirements	Q1 – Q4 2020-21		✓	☑	
Enable broader participation in the Capacity Market					
Capacity Market Modelling	Q4 2019-20			☑	
Ongoing Regional Development Programmes		Exceeding			
Commercial contracts for balancing services from DER	Q4 2020-21				☑
Enhanced systems to facilitate balancing services from DER	Q4 2020-21				☑
Automated dispatch capability for generation in highly constrained areas	Q1 2020-21				☑
Development of a proactive RDP identification process	Q3 2019-20				☑
Whole system data exchange		Exceeding			
Extended roll out of enhanced whole system data exchange	Q2 2019-20		✓		☑

Deliverable	Delivery date	Meeting or exceeding baseline expectations	Role		
			1	2	3&4
Commercial flexibility around operational connections	Q1 2019-20		✓		☑
Whole system operability		Exceeding			
Roll out of Loss of Mains Protection setting	Commencing Q1 2019-20		☑		✓
Defining roles and responsibility for voltage management across the transmission-distribution interface	Q3 2019-20		✓		☑
Inertia Measurement	Q1 2020-21		✓		☑
Enhanced customer experience					
Transmission Outage and Generator Availability (TOGA) replacement	Q4 2019-20	Meeting			☑
Customer journey mapping – outage planning	Q1 2019-20				☑
Connections customer portal		Exceeding			☑
Whole electricity system thought leadership		Exceeding			
ESO thought leadership – how our role will evolve	Q1 2019-20		✓	✓	☑
Whole electricity system learnings	Q2 2019-20, update Q2 2020-21		✓	✓	☑
ENA Open Networks project 2019 ESO input	Q3 2019-20		✓	✓	☑
ENA Open Networks project Whole Energy System lead	Q3 2019-20		✓	✓	☑
Pathfinder projects		Exceeding			
Stability pathfinder	Q1 2020-21				☑
Mersey Voltage pathfinder	Q3 2019-20				☑
Pennines Voltage pathfinder	Q3 2019-20				☑
Constraint Management Pathfinder	Q2 2020-21				☑
Study tools					☑
Voltage needs identification tools/ processes	Q4 2020-21				☑
Thermal probabilistic assessment tool / process	Q3 2019-20				☑

Deliverable	Delivery date	Meeting or exceeding baseline expectations	Role		
			1	2	3&4
NOA: Enhanced communication					
Improve accessibility of ETYS and NOA publications	Ongoing	Meeting	✓		☑
Deeper system access planning					
Deeper access co-ordination of 1-2 major infrastructure projects to commence in the RIIO-T1 period	Q4 2020-21	Exceeding	✓		☑

Performance metrics

This table summarises the metrics listed within the role delivery sections.

	Metric	Reporting frequency	Role		
			1	2	3&4
1	Balancing cost management	Monthly	✓		
2	Information provision scorecard	Quarterly	✓		
3	Energy forecasting accuracy	Monthly	✓		
4	Provider journey feedback	Quarterly		✓	
5	Reform of balancing services markets	Quarterly		✓	
6	Code administrator: stakeholder satisfaction	Quarterly		✓	
7	Charging Futures	Quarterly		✓	
8	Year ahead forecast vs outturn annual BSUoS	Annual		✓	
9	Month ahead forecast vs outturn monthly BSUoS	Monthly		✓	
10	Whole system, unlocking cross boundary solutions	Quarterly			✓
11	System access management	Monthly			✓
12	Customer value opportunities	Quarterly			✓
13	Connections agreements management	Monthly			✓
14	Right first time connection offers	Monthly			✓
15	NOA consumer benefit	Annual			✓
16	Enhancing communication	Quarterly			✓

C
Delivering Consumer Benefit

Delivering Consumer Benefit

As outlined in Appendix A, our performance against the Incentives Framework is evaluated through five criteria; evidence of delivered benefits and evidence of future benefits requires us to demonstrate and evidence the achievement of additional consumer benefits within the relevant performance year and in the long-term. Given the broad range of benefits that we deliver, it is challenging to provide quantitative explanations of how all of our activities deliver tangible impacts on the consumer bill. Where we believe it is possible to use a quantitative approach to estimate how activities deliver benefits we have provided case studies.

As outlined by our mission, delivering benefit for consumers is at the heart of everything that we do. Throughout the plan, we have articulated how our activities in 2019-21 will deliver benefits for consumers against the following categories:

- Improved safety and reliability,
- Improved quality of service,
- Lower bills than otherwise the case,
- Reduced environmental damage,
- Benefits for society as a whole.

Purpose of these case studies

It is challenging to estimate the consumer benefit given the wide range of direct and indirect effects that our activities deliver. Where we have a direct impact on the consumer bill, we have provided case studies of how we deliver consumer benefit now, and unlocking in the future. As the scope of roles cut across all of our activities this case studies, we have identified where a case study provides benefit to more than one role; for this reason, the case studies are not intended to be aggregated as this will lead to some double counting of benefit delivered. The examples are summarised in the following table, with further detail following.

Consumer benefit case studies index

	Case study title	Role			Forward Plan deliverables	Delivered and future benefit
		1	2	3&4		
1	Increasing competition in balancing service markets	✓	✓		• Publish operational insights information • Open data • Initiatives and commitments detailed in *Product Roadmaps* for Response, Reserve, Reactive and Restoration • Power Responsive programme • Wider access to BM programme	Up to £35m per annum to be delivered from 2021
2	Improving BSUoS forecasting	✓			• Metric 2 covering BSUoS reports and BSUoS forecast provision. • Metric 9 – Month ahead forecast vs outturn monthly BSUoS	Up to £80m over the next 10 – 15 years
3	ENCC and short-term operational decision making	✓			• Metric 1 – Balancing Cost Management • Operational insights • Transparency around our data	Potential for £50m-£100m per year now and into the future

Case study title		Role			Forward Plan deliverables	Delivered and future benefit
		1	2	3&4		
4	Future operability challenges	✓			• Operability reports and information • Transparency around our data • Addressing operational issues	Up to £500m per year in 2029.

5	Energy forecasting	✓			• Upgrade of information systems – Energy Forecasting System
					• Forecasting:
					  • Forecasting Strategy project roadmap
					  • Publication of additional PV, Wind, DA demand forecasts
						Potential for £80m – £120m savings by 2024.

6	Frequency response auction platform trial		✓		• *Product Roadmaps* for Response and Reserve Implementation	Up to £6m savings in balancing services costs after the end of the 2-year trial period.

7	Facilitating code change		✓		• Facilitating code change
					  • Get the basics right
					  • Enabling all network users to understand and contribute to the code change process
						Potential for hundreds of millions of pounds over the next 20 years.

8	Changing embedded generator protection systems	✓	✓		• Addressing operational issues	More than £170m per year from 2022-23.
9	Whole system approach to cross boundary working	✓		✓	• Ongoing RDPs • Development of a Proactive RDP Identification Process	Up to £350m over the next 40 years from South West Scotland RDP.
10	Whole electricity system thought leadership	✓		✓	• Whole electricity system thought leadership • Whole system operability • Transform industry frameworks to enable decentralised, decarbonised and digitised energy markets	Potential for hundreds of millions of pounds per year in 2030.
11	Adding commercial solutions to the			✓	• Enhanced communication of NOA to increase the number and type of participants; • Metric 15 NOA consumer benefit.	Potential of between £0.77bn and £1.1bn over the next 10 years

Case study title		Role			Forward Plan deliverables	Delivered and future benefit
		1	2	3&4		
	NOA Process					
12	High voltage Pathfinder			✓	• Supporting competition in networks • Facilitating whole system outcomes	Potential benefit up to £36m per year, after 2021.
13	Network Options Assessment			✓	• Metric 15 – NOA consumer benefit • NOA: Enhanced communication	Up to £2.67bn avoided dis-benefit over a 40-year rolling period, updated yearly.
14	The CION process			✓	• Enhanced customer experience	Between £1bn-£2bn over 25 years
15	The SWW process			✓	• Enhanced customer experience	Between £202m-£404m per year, with the benefits realised over 40 years.

1. Increasing competition in balancing service markets

Consumer Benefit Outcome

Activity	We will increase competition in existing balancing service markets, and introduce competition where none exists. We do this through a wide range of deliverables and activities, from providing more information to facilitate markets, through to simplifying and rationalising our product requirements through our roadmaps. We are a fundamental driver of this reduction in costs due to increased competition, as we are the sole purchaser of balancing and ancillary services, and as such must act proactively to develop and facilitate the markets.
Role	1. Managing system balance and operability 2. Facilitating competitive markets.
Key Forward Plan deliverables	• Operational insights • Open data • Initiatives and commitments detailed in *Product Roadmaps for Response and Reserve* implementation • Initiatives and commitments detailed in *Product Roadmap for Restoration* implementation • Power Responsive programme • *Wider Access to Balancing Mechanism Roadmap* implementation • Provider experience • Metric 1 – Balancing Cost Management • Metric 4 – Provider Journey Feedback • Metric 5 – Reform of balancing services markets
Delivered and future benefit	Up to £35m per annum to be delivered post 2021.
	Benefits are already being realised as we see submitted prices falling for some of the products we procure, such as STOR and FFR. We expect increasing competition in balancing services markets to continue to deliver benefits for consumers over the next ten years. As highlighted in our *Operability Strategy Report*, operational challenges are ever-increasing as we continue the transition to a low-carbon energy landscape; without our intervention, balancing costs will increase due to the increasing complexity and challenges of system operation. Increasing competition to drive down prices is a crucial counter to the increase in costs due to system operation complexity. Over the next 10 years as our deliverables increase market competition there are benefits of £35m per year to be gained from increasing competition in balancing and ancillary markets. There will be a lead time of several years as the changes we put in place feed through into tangible market behaviour which result in lower balancing costs for us. We estimate that we will see the maximum benefit by the end of 2021. Note that the £35m per annum we identify is a yearly saving against the counterfactual of what we spend today. We estimate that we can save £35m/year in the future at a flat rate in today's money. We are not proposing that costs will reduce by an additional £35m per annum year-on-year.

Basis of expected benefit	The total value of services in scope for increased competition is £353m per annum and is forecast to increase over the coming years. By increasing competition in already competitive markets, and introducing competition where none currently exists, we can drive down the spend in these areas.

Average annual spend 2016-18 on services where competition can be increased	
Market-based services	£155m
Non-market-based services in scope for development of market-based mechanisms	£198m

How benefit is realised in the consumer bill	The money we spend on commercial actions to balance and operate the system is levied on system users via the BSUoS charge, which is a pass-through cost to the end-consumer. We will increase competition to drive down the prices we pay in these markets, which will reduce the BSUoS cost when compared to a counterfactual of us not working to increase competition.
Additional non-monetary benefit	There are environmental and security benefits which arise from increased competition specifically many new suppliers tend to be low-carbon, and a greater range of diverse providers and technologies can add to system resilience.

Assumptions

- Increasing competition has driven down STOR market prices.
- Variations in the STOR prices between 2014-15 and 2018-19 correspond to variations in competition. We measured competition in this period by looking at the ratio of tenders accepted as a percentage of total tenders received. See Figure 6 below.

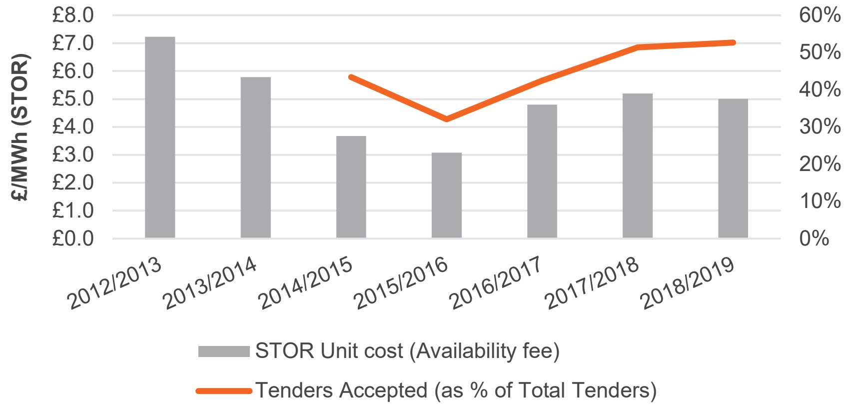


Figure 6: Variation in STOR price against proportion of tenders accepted.

- STOR unit cost (availability fee) decreased by 58% between 2012–16. Some of this is likely related to wholesale price, which reduced by 17% over this period.
- STOR unit price decreased at a faster rate than wholesale price between 2012-16, indicating competition was a major factor. See Figure 7 below.

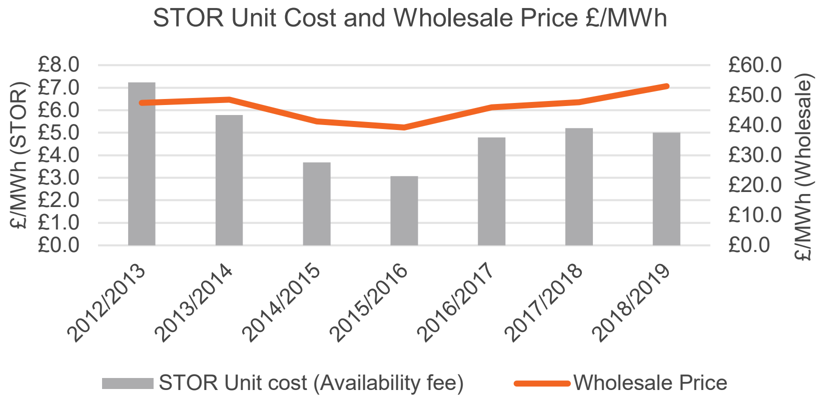


Figure 7 STOR unit cost and wholesale price

- Factors including increased competition in the STOR market between 2012-13 to 2015-16 corresponded to a reduction in STOR unit cost of around 40%.
- 50% of this saving was due to increased competition.
- A conservative estimate is that our actions will contribute to generating 50% of the savings from increasing competition.
- This creates a multiplier of 40%*50%*50%=10%, which is how much our actions can drive price down due to increasing competition.
- Looking at the total value of our competitive and non-competitive markets, we believe there is value to be unlocked in the order of £35m per annum.

Consumer Benefit Outcome

2. Improving BSUoS forecasting

Activity	We are working to improve our BSUoS forecasts in all timescales. Suppliers can act on this better-quality information to reduce the level of risk premia added to the consumer bill to account for BSUoS volatility and uncertainty.
Role	1. Managing system balance and operability 2. Facilitating competitive markets
Key Forward Plan Deliverables	• Metrics: 2 – information provision scorecard, 8 – Year ahead forecast vs outturn annual BSUoS, 9 – month ahead forecast vs outturn monthly BSUoS and 1 – Balancing Cost Management
Delivered and future benefit	Up to £80m over the next 10 – 15 years. We will deliver this benefit through lower bills due to a reduced risk premia component being held by system users.
Basis of expected benefit	A code modification proposal[27] which sought to fix BSUoS cost, looked at quantifying the risk premia held by suppliers. A risk premia figure of £75m was proposed, although the report also proposes that for market participants to ensure that 70% of the time they make no losses attributable to BSUoS volatility then over-recovery of cost from consumers would be between £81m-£201m per year (see paragraph 2.121[28]). Assuming there is a risk premia of £80m per year in the market, we believe a conservative estimate that improving our forecasts could reduce that by 10%, leading to a lowering in risk premia component of the consumer bill by £8m per year, or up to £80m over the next 10-15 years. There would likely be a time lag between better forecasting being recognised by the market and then that confidence in the forecasts feeding into reduced risk premia, hence our estimate of the saving being spread over a period up to 15 years.
How benefit is realised in the consumer bill	Benefit for consumers comes through suppliers reducing the risk premia that gets added to consumer bills. Suppliers are likely to reduce their risk premia added for BSUoS volatility if our forecasts improve.
Additional non-monetary benefit	Better quality of service to the industry through delivering better forecasting and information, such as a day-ahead half-hourly BSUoS forecast.
Assumptions	• We produce BSUoS forecasts in various timescales to send price signals to the market. We are working to improve our BSUoS forecasting in all timescales. • BSUoS costs are becoming more unstable due to increased complexity of system operation. • A lack of confidence in BSUoS forecasts mean generators and suppliers factor in risk premia that get passed onto consumers. Accurate forecasts lower risk premia and reduce consumer bills. • We assume that suppliers will reduce their risk premia which they include as part of the consumer bill as we improve confidence in our forecasts, which will reduce pricing uncertainty.

[27] https://www.nationalgrideso.com/document/106876/download
[28] https://www.nationalgrideso.com/document/106876/download

Consumer Benefit Outcome

3. ENCC and short-term operational decision making

Activity	Our ENCC and associated supporting commercial and planning teams are making decisions on optimising the economic operation of the system on a daily and within-day basis.
Role	1. Managing system balance and operability
Key Forward Plan Deliverables	• Operational insights • Transparency of data used by our ENCC in our close-to-real-time decision making • Metric 1 – Balancing Cost Management
Delivered and future benefit	Potential for £50m-£100m per year. This is based on value of £42m per year, being delivered now and every year, from our limited counterfactual reporting to date.
Basis of expected benefit	Our monthly performance reporting[29] includes detail on savings from short-term decision making. For October to December 2018 we noted savings per month between £1.4m and £3.5m. These are conservative estimates as, due to the volume of actions we take, not all actions are reported against a counterfactual. Extrapolating over a year, we estimate we can deliver benefit of £17m - £42m per year. We believe there is potential for £50m-£100m to be realised, because the counterfactual to date is limited and we have not applied analysis to all the activity we have done to deliver value. There are many opportunities for the relevant teams to create benefit by reducing the spend on operating the system by taking pro-active problem solving approaches. Some ways we reduce costs are: • Trading on interconnectors for negative reserve as opposed to taking action on wind plant and two-shifting BM plant, • Trading on interconnectors for margin, • Using super SEL contracts to reduce negative reserve costs, • Reassessing constraint limits closer to real-time, • Reducing the requirement for voltage support machines by re-assessing system real-time system needs, • Optimising actions to manage RoCoF, e.g. trading units on to increase inertia as opposed to reducing largest loss and wind output, • Re-configuring substation arrangements to optimise network flows and decrease congestion problems.
How benefit is realised in the consumer bill	WE spend money to balance and operate the system which is levied on system users via the BSUoS charge. This is paid by system users who pass it through to end consumer via the 'bill'. Any cost avoidance, reduction, or savings we make to this spend will directly benefit the consumer. Our benchmark cost for BSUoS spend is approximately £1bn for 2019, as detailed in Metric 1. Any reduction we can make to this significant spend through our actions and decision making will benefit the consumer.
Assumptions	• We will continue to use our system operation, commercial, and engineering expertise and judgement to identify cheaper ways of solving system issues close to real-time.

[29] https://www.nationalgrideso.com/about-us/business-plans/how-we-are-performing

Consumer Benefit Outcome

4. Future operability challenges

Activity	We use our engineering expertise to identify future operability challenges well in advance and communicate this to industry via our *Operability Strategy Reports*. We will accompany this with proposals for how to address challenges from both technical and market perspectives. This will give advance signals to potential solution providers, so that we can be well placed to secure the system at optimum cost, avoiding expensive resolutions to operational scenarios which could have been foreseen.
Role	1. Managing system balance and operability
Key Forward Plan Deliverables	• Operability reports and information • Transparency of data used by our ENCC in our close-to-real-time decision making • Addressing operational issues • Metric 1 – Balancing Cost Management
Delivered and future benefit	Potential to save up to £500m per year in 2029. The consumer will benefit directly from any savings, reductions, or cost avoidance we make in this area. If we do not focus on controlling system operation and balancing costs, industry views are that they could double or more over 10 years. We estimate we should be able to impact up to 50% of this projection, thereby avoiding spend of up to £500m per year in 2029. Benefits from work coming from our operability reports are already being seen, as reported elsewhere here, such as through our RDPs. We will see benefits arising from our focus on operability materialising over the next 10 years as we develop solutions to the operability challenges.
Basis of expected benefit	• External reports[30] and academics have modelled that the costs of operating and balancing the system will rise significantly over the next 10 years: in some analysis, more than doubling. • BSUoS costs are currently in the region of £1bn/year. • If BSUoS costs were to double in ten years compared to today's costs, as predicted by some observers, we are centrally placed to intervene to put mitigations in place. Our actions should be able to impact up to 50% of those additional costs due to operability challenges. That could result in consumer benefit of up to £500m per year by 2029. • We must take action, otherwise it is likely that the costs forecasted by these models and reports would materialise. • For example, the report 'Delivering future-proof energy infrastructure' states: "Analysis demonstrates that the value of ancillary services market, if supplied by conventional plant only, would increase about 10 times, which should provide strong incentives for non-traditional technologies and solutions to compete"[31].

[30] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/568982/An_analysis_of_electricity_flexibility_for_Great_Britain.pdf
https://www.nic.org.uk/wp-content/uploads/Delivering-future-proof-energy-infrastructure-Goran-Strbac-et-al.pdf

[31] https://spiral.imperial.ac.uk/bitstream/10044/1/33703/6/TengStrbac_IEEE_V4_Revised_V15.pdf

How benefit is realised in the consumer bill	System users pay for the cost of system operation through the BSUoS charge. Any increase in this will directly affect consumers as it is a pass-through cost to them.
Additional non-monetary benefit	Our focus on future operability will ensure the electricity system is secure and resilient in the future, enabling uninterrupted supply of power to consumers at optimum cost.
Assumptions	We assume that we will be able to identify and implement solutions in time to resolve issues before they become a threat to system security and economic system operation.

Consumer Benefit Outcome

5. Energy forecasting

Activity	Our Energy Forecasting mission is to constantly improve energy forecasting accuracy, increase the frequency of key forecasts, and publish available data and information to industry. Accurate Day Ahead demand forecasts (DA) and DA Balancing Mechanism Unit (BMU) wind generation forecasts are essential to support the market to balance its position ahead of real time. Accurate and timely forecasts are also essential to enable the ENCC to plan and operate the system securely and economically.
Role	1. Managing system balance and operability
Key Forward Plan Deliverables	• Upgrade of information systems – Energy Forecasting System • Forecasting
Delivered and future benefit	Potential for savings of £80m-£120m per year by 2024.
	We estimate that of the approximately £1bn spent every year to balance the network, one quarter is driven directly or indirectly by the accuracy of our energy forecasts. If it was possible to reduce the forecasting error of all our forecasts to zero, we could potentially save approximately £250m of consumers' money every year. Reducing the error of our forecasts to zero is an unrealistic target but we strive to improve our accuracy because better forecasts will allow us to manage the network more economically, whilst remaining secure.
Basis of expected benefit	We estimate that an improvement in the accuracy of our demand forecasts by 100MW could result in £40m - £60m reduction in the annual cost incurred to balance the system compared to today's levels. We estimate that if we do nothing to improve our forecasts then the accuracy of the demand forecast is likely to decrease by 100MW over five years due to the increasing amounts of intermittent generation, DER, and changing consumer behaviour, which would lead to an increase in costs of £40m-£60m. In five years' time, the difference between doing nothing and improving our forecasting could lead to a potential saving of £80m-£120m. This is illustrated in Figure 8 below, which shows that if we do not react to address the increasing complexity of forecasting the electricity system, the annual cost of balancing the network related to the forecasting error is likely to increase (red dotted line); however, by improving our forecasting accuracy, this balancing cost can be reduced (blue dotted line).

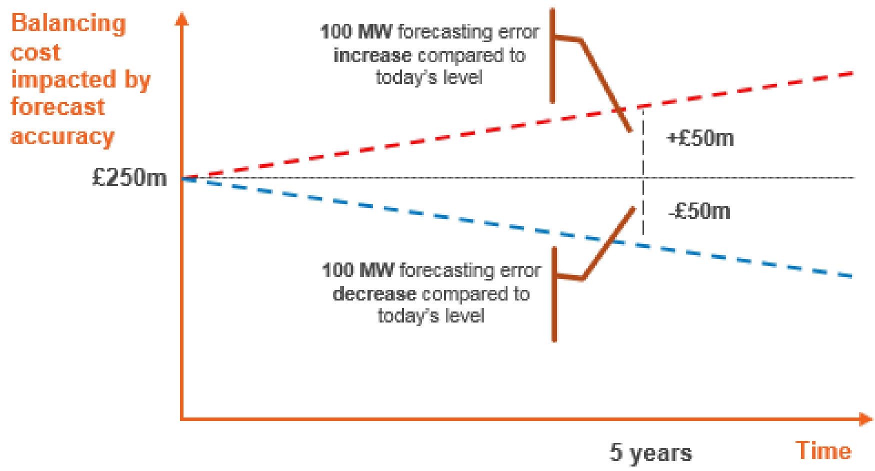


Figure 8: Impact of forecasting accuracy on balancing cost

Energy Forecasting is working on several strategic areas to deliver tangible benefits to consumers:

1. Accuracy of our forecasts. Accurate forecasts will allow market participants to better adjust their generation/consumption positions ahead of real time. This will result in fewer actions taken by the ENCC, and therefore less consumers' money spent to balance the electricity system.
2. Frequency of our forecasts. More frequent forecasts will allow market participants to better adjust their positions closer to real time. This will help organisations to optimise their balancing decisions and therefore reducing the number of actions that we need to take to balance the system.
3. Transparency and accessibility of our forecasts. Easy to understand and more accessible forecasting data will lead to more efficient markets and potentially remove barriers to entry.

How benefit is realised in the consumer bill	System users pay for the cost of system operation through the BSUoS charge. Any increase in this will directly affect consumers as it is a pass-through cost to them. If we do not work to improve our forecasting, we believe the costs to the consumer will increase due to increasing BSUoS cost. If we can improve our forecasts such that accuracy improves, then this should lead to a cost saving.
Additional non-monetary benefit	Better service for users of our forecasts outside of the ESO.
Assumptions	Increasing amounts of both transmission connected and embedded wind and solar generation, alongside DER, will make energy forecasting more difficult, which could lead to higher costs.

Consumer Benefit Outcome

6. Frequency response auction platform trial

Activity	We currently procure the balancing service product frequency response through monthly tenders. Stakeholders have told us that they want to see us moving toward more transparent procurement closer to real-time.
Role	2. Facilitating competitive markets
Key Forward Plan Deliverables	• *Product Roadmaps* for Response and Reserve implementation
Delivered and future benefit	Potential for maximum of £6m per year savings in balancing services costs after the end of the 2-year trial period.
	These savings will be due to lower prices realised through the platform, giving a consumer benefit of up to £6m per year after the trial as we move to more frequent closer to real-time procurement of services. Note that this figure is the maximum we could achieve if all our procurement was moved to the auction platform. If we still procure some volume from longer-term monthly auctions and the intra-day mandatory market, we may not achieve this maximum.
Basis of expected benefit	The auction trial will lower BSUoS costs through increasing competition in the market, and increasing liquidity, as new and existing providers will find it easier to participate in the market via the new platform. The platform should open up the market to more renewable, embedded and demand-side flexibility participants. We currently buy our tendered products up to 24 months in advance. By moving to a more frequent procurement closer to real-time, participants should get better price signals and we will not be locked in to longer term contracts. The NIA Project Registration Document[32] for the auction platform trial estimates a 5% cost reduction in price as successful outcome of the trial. In 2017-18 Commercial Frequency and Mandatory Frequency costs were £99m and £21m respectively. If these costs remain static by the end of the trial period, then we should see savings of 5% of £120m = £6m if we were able to move all procurement into the auction platform.
How benefit is realised in the consumer bill	The balancing services products we use paid for via the BSUoS levy on system users, which ultimately gets passed through to the end consumer. By driving down prices in the markets we procure products and services, we will drive down the pass-through BSUoS costs for consumers.
Additional non-monetary benefit	There will be environmental benefit due to more low-carbon and demand-side providers being able to participate in the market via the new platform.
Assumptions	There will be greater participation in the trial than the requirement we are buying for, which, together with sufficient liquidity, will drive lower prices.

[32] http://www.smarternetworks.org/cdn/pdf/niaregistration/d2638a2f-3891-45c2-b729-a9ac00b10915

Consumer Benefit Outcome

7. Facilitating code change

Activity	We want our codes to facilitate the rapid change required to deliver the UK's 2050 carbon reduction target. By 2025, our codes and code governance will no longer be perceived as a barrier to change. Code modification will work for hundreds of market participants, rather than the tens of participants for which the current process was devised. We will work with industry to ensure codes keep pace with the rapidly changing energy generation and supply landscape so that the industry can operate efficiently and effectively for the benefit of the consumer. We will help stakeholders access information in a clear and transparent way, to enable informed and value-adding debate. We will work to implement code change in a timely manner, to deliver benefit to the consumer as early as possible.
Role	2. Facilitating competitive markets
Key Forward Plan Deliverables	• Facilitating code change
Delivered and future benefit	Potential for hundreds of millions of pounds over the next 20 years
	We are not solely responsible for the significant savings which are realised through code change. We work with industry and the regulator to facilitate robust framework development and expedient delivery of changes. The sooner changes are delivered, the sooner the consumer starts to see benefit through their bill. Code changes can deliver huge benefit, for example, code modification proposals[33] to change electricity transmission charging arrangements for Embedded Generators identified benefits of £7bn over the periods 2021 – 2034. However, many code changes deliver small benefit, therefore it is difficult to estimate the value of benefit which could materialise in the code-change pipeline. Nevertheless, in the context of recent changes which have delivered billions of pounds of benefit, and the transformational change facing the industry as we move to a low-carbon decentralised system, there is no doubt that we can contribute to delivering significant benefit to the end consumer over the next 10 years.
How benefit is realised in the consumer bill	Each code varies in which element of the bill they affect from direct BSUoS changes to wider industry change seen through the wholesale market. By enabling better functioning markets and supporting new entrants which stimulates competition, well facilitated code change reduces the end-consumer bill.

[33] https://www.ofgem.gov.uk/system/files/docs/2017/06/impact_assessment_and_decision_on_industry_cmp264265.pdf

Basis of expected benefit	We are currently a Code Administrator for the following codes: CUSC, STC and the Grid Code. Benefits to the consumer will result from earlier implementation of code changes and modification, than current BAU activities. The increase in transparency and simplicity will open this market to new and innovative players, increasing competition and facilitating more efficient codes for all players. Benefits would be linked to each individual code. For the speed of code modifications and changes the benefits are for the additional period they will be implemented. We will deliver improved quality of service benefits through focus on our stakeholders, suppliers, providers and customers, which should in turn, benefit the customers of those organisations, and their end consumers. Assumption on the benefits of individual codes are from Ofgem[34] and wider benefits from the CMA 2016 energy market investigation[35] report.
Additional non-monetary benefit	We will deliver better service to industry participants to make navigation through the codes processes easier.
Assumptions	Network charges (DUoS, BSUoS, TNUoS) are passed through to the consumer, and as such when we can deliver code changes which avoid, reduce, or optimise across them, then this component of the end-consumer bill will be lower than if we had not taken this action.

[34] https://www.ofgem.gov.uk/system/files/docs/2018/07/consumer_impact_report_-_published0307.pdf
[35] https://assets.publishing.service.gov.uk/media/5773de34e5274a0da3000113/final-report-energy-market-investigation.pdf

Consumer Benefit Outcome

8. Changing embedded generator protection systems

Activity	We currently use commercial actions to manage a system operability problem caused by protection systems on some embedded generators. This spend is an external component of BSUoS, a pass-through cost to the end-consumer. The problem is referred to in the industry as Loss of Mains protection, RoCoF and Vector Shift. We will create benefit by working with all the DNOs to agree an accelerated change programme to curtail these costs earlier, by modifying effected generator protection systems.
Role	3. Facilitating whole system outcomes 1. Managing system balance and operability
Key Forward Plan Deliverables	• Addressing operational issues • Metric 1 – Balancing Cost Management
Delivered and future benefit	More than £170m per year from 2022-23.
	Between 2019 and 2022, we will run a 3-year programme to change the protection settings on affected embedded generators. The program of change is currently forecast to cost £60m. This cost will be charged through BSUoS over the relevant timeframe. Once the program is complete, the commercial cost of managing the problem will reduce to £0. The table below shows how we forecast the cost of the problem will increase if we do nothing; the costs of implementing the change program; and the impact of the change program on costs.

£m		19-20	20-21	21-22	22-23	23-24	24-25
Do Nothing	Forecast Balancing Costs	130	150	150	170	190	290
	Cumulative	130	280	430	600	790	1080
Implement Change Programme	Forecast Balancing Costs	130	150	40			
	Forecast Change Costs	20	30	10			
	Total Balancing Costs	150	180	50			
	Cumulative	150	330	380			

Table 5 RoCoF forecast costs and change programme costs

Basis of expected benefit	We will create benefit by working with all the DNOs to agree an accelerated change programme to curtail these costs earlier, by modifying effected generator protection systems. This would not be possible without us working closely with the DNOs and the regulator to agree an accelerated plan to solve the problem at the generator protection systems. We are also driving through a code modification to ensure this can happen. We believe this is adding additional value, as there is no direct impetus on industry to solve this via a code modification without our intervention.
How benefit is realised in the consumer bill	The problem is managed through commercial actions paid for through BSUoS. The cost of the programme to resolve the problem will also be levied through BSUoS. Therefore, there will be additional cost over the 3-year programme period, but as we move through the programme into its third year, the commercial cost of managing the problem will reduce, and upon completion of the programme will reduce to zero.
Additional non-monetary benefit	There is potential environmental benefit because we will not have to explore other options for RoCoF management which could include curtailment of non-synchronous generation, which are usually low-carbon sources. There is also benefit to system security due to elimination of the situation where generation may disconnect unnecessarily due to fault conditions.
Assumptions	We assume that any reduction in BSUoS gets passed through to consumers.

9. Whole system approach to cross boundary working

Consumer Benefit Outcome

Activity	We are finding the right balance between operational cost and network costs in developing our solutions to future requirements. Previously network licensees would only have looked as far as their system boundary when looking at options. We are now looking across system boundaries to find the most efficient solution. We are now highlighting the most efficient solution, and looking at the problem as if system boundaries are transparent.
Role	3. Facilitating whole system outcomes 1. Managing system balance and operability
Key Forward Plan Deliverables	• Ongoing RDPs • Development of a Proactive RDP Identification Process
Delivered and future benefit	Up to £350m over the next 40 years from South West Scotland RDP, and up to £10m per site over 40 years for each subsequent RDP.
	For the South West Scotland area we have undertaken a CBA which showed around £500m of consumer value in not building transmission assets. This will be a TNUoS saving. This is balanced against an additional projected BSUoS spend to constrain generation of £150m, giving a net consumer benefit of £350m. As we work through other Pathfinders, RDPs, and cross-boundary options we will perform CBAs/counterfactuals to assess their value.
Basis of expected benefit	• We are the central coordinator. We drive and lead the looking at what is solvable and delivering the optimum cost solution from a range of options. • We scan the system for opportunities, inviting relevant parties, such as DNOs, to work with us to drive overall system cost down. When these parties on board, we partner with them to deliver the agreed solutions. Examples are described below. • Recently we have seen examples of generation has connected to the UKPN network before they would have previously been able to. There would have needed to be transmission investment first, now this is not the case as contractual solutions have been put in place which provide the facilities needed to avoid the network investment. • We have previously released capacity in the Dumfries and Galloway region, deferring transmission investment. The CBA for South West Scotland shows in the region of £500m of consumer value in not building network infrastructure, and now we need to develop the Generation Export Management Scheme to support this saving and develop an effective and competitive local solution in a whole system context. We estimate we will spend £150m in additional constraint costs due to the deferred transmission investment, giving a net consumer benefit of £350m. • We are delivering a RDP with WPD focusing on storage, the benefits of which are up to £10m in avoided investment. • We are working with Electricity North West to determine the most efficient site for reactor deployment, the benefit is up to £5m realised by highlighting the optimal network infrastructure solution.

How benefit is realised in the consumer bill	• Various charges on system users are passed through to the end-consumer. These can be for use of the distribution system (DUoS); the costs incurred by the system operator in running the system (BSUoS); and the cost of building and maintaining the system levied by the TOs (TNUoS). • Choosing solutions which have an optimum cost across all these charges will lessen the total cost passed through to the end-consumer.
Additional non-monetary benefit	There may be additional benefits such as environmental, both when we allow generation to connect earlier (if it is low-carbon, which is likely), and if we defer or avoid physical asset build.
Assumptions	Network charges (DUoS, BSUoS, TNUoS) are passed through to the consumer, and as such when we can optimise across them through whole-system solutions and approaches, then this component of the end-consumer bill will be lower than if we had not taken this action.

10. Whole electricity system thought leadership

Consumer Benefit Outcome

Activity	We play a key role in the ENA Open Networks project; we will be actively involved across all workstreams and 2019 deliverables. We continue to support this project and identify areas for us to take a lead on. Across the ENA Open Networks workstreams, we are engaged in over 30 working groups and/ or product development groups.
Role	3. Facilitating whole system outcomes 1. Managing system balance and operability 2. Facilitating competitive markets
Key Forward Plan Deliverables	• Whole electricity system thought leadership • Whole system operability • Transform industry frameworks to enable decentralised, decarbonised and digitised energy markets
Delivered and future benefit	Potential for hundreds of millions of pounds by 2030. This is a conservative estimate, based on industry reports (see links below). They estimate there is up to £8bn per year of savings to be had for the end consumer by 2030 if industry works together to intervene to resolve issues which are being created by the move to a low-carbon decentralised electricity system. As the System Operator at the centre of the energy revolution, we will contribute to a significant amount of those savings.
Basis of expected benefit	Work in this area is fundamental to the achievement of an economic and securely operable electricity system in the future. Current research[36] from Energy UK, ADE, Ovo Energy demonstrates that if industry works together to solve the challenges appearing on the system as a result of the transition to a low-carbon environment, there are immense benefits to be realised for the end consumer. For example: • The often-cited papers[37] for the National Infrastructure Commission puts the upper bound of consumer benefit in the region of £8bn/year in 2030. • The Roadmap For Flexibility Services To 2030 for the Committee on Climate Change states "that the coordinated (i.e. whole-system) approach may result in significant additional savings in system operation and investment costs, i.e. between £1.1bn per year and £2.3bn per year, relative to transmission or distribution network centric models."[38] We are a key player in the transition of the electricity system to its low-carbon decentralised future state, and as such will contribute significantly to deliver future consumer benefits in this area.

[36] https://www.energy-uk.org.uk/publication.html?task=file.download&id=5722
https://www.theade.co.uk/assets/docs/resources/Industrial flexibility and competitiveness report_v10 web.pdf
https://www.ovoenergy.com/binaries/content/assets/documents/pdfs/newsroom/blueprint-for-a-post-carbon-society-how-residential-flexibility-is-key-to-decarbonising-power-heat-and-transport/blueprintforapostcarbonsocietypdf-compressed.pdf
[37] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/505218/IC_Energy_Report_web.pdf
38 https://www.theccc.org.uk/wp-content/uploads/2017/06/Roadmap-for-flexibility-services-to-2030-Poyry-and-Imperial-College-London.pdf page 42

How benefit is realised in the consumer bill	Without intervention, the end consumer will face significant increases in the bill through: • System operational challenges via BSUoS; • More requirement for transmission system build via TNUoS; • More requirement for DNO assets via DUoS.
Additional non-monetary benefit	Working across industry to deliver a system fit for the future which is safe, reliable, and can be operated economically, will benefit society as we transition to a low-carbon economy.
Assumptions	Industry will work together expediently across boundaries to achieve the best outcomes in the consumers' interests.

11. Adding commercial solutions to the NOA process

Consumer Benefit Outcome

Activity	We are looking at solutions such as commercial intertrips as part of the NOA process, as an alternative to traditional asset based solutions.
Role	4. Supporting competition in networks.
Key Forward Plan Deliverables	• Enhanced communication of NOA to increase the number and type of participants • Study tools • Metric 15 NOA consumer benefit.
Delivered and future benefit	Potential benefit of between £0.77bn and £1.1bn over the next 10 years We expect to deliver on average between £76m and £109m per year of benefit for consumers, as we publish our NOA recommendations for the development of the network. The benefit will be realised when the communication systems can be installed and the contracts negotiated. Full delivery of the benefit is dependent on sufficient participation and capability from stakeholders to deliver the solutions.
Basis of expected benefit	• Commercial intertrips will allow more power to flow pre-fault by securing the network with a post fault commercial action. This has been shown to reduce the cost to alleviate network constraints. • Commercial intertrips may also reduce TNUoS where they delay or negate the need to build an asset based solution. • The mechanism to create this benefit was SO initiated commercial solutions. • The commercial solutions are SO created, SO negotiated and SO operated. There will be minor work to the TOs to build the communications infrastructure.
How benefit is realised in the consumer bill	Network constraints are managed and paid through the BSUoS charge, levied on system users and passed through to the end consumer. Transmission builds are paid for through the TNUoS charge, paid by system users and also ultimately paid by the end consumer. This work will optimise the spend on BSUoS and TNUoS when looking at the ideal solutions to manage network constraints.
Additional non-monetary benefit	There are additional benefits to society of reduced visual amenity impacts if we do not have to build physical assets across the landscape.
Assumptions	• The main assumption is that commercial intertrips can be negotiated and activated at the right time. • Operating the network could become more difficult with more automation, we need to ensure the commercial solutions are operable and viable for the ENCC to use. • Commercial intertrips can provide economic benefit, and are not a measure to achieve network compliance.

Consumer Benefit Outcome

12.High voltage pathfinder

Activity	A pathfinding project is a ‘trial by doing’ approach to develop new processes, expand capabilities and learn along the way often requiring collaboration between us, TOs and DNOs. We use pathfinding projects to develop the capabilities that we and other parties need to take forward expanding our approach to network development: developing a cost-benefit analysis that compares network and non-network solutions that have different lifetimes or contracting periods
Role	4. Supporting competition in networks 3. Facilitating whole system outcomes
Key Forward Plan Deliverables	Pathfinder projects
Delivered and future benefit	Potential benefit of up to £36m per year after 2021 The savings are across the all the voltage pathfinder projects. The value will materialise after completion of the RFI and subsequent project recommendations (due 2019-20) and be realised once solutions are implemented. Solutions are likely to be in place after 2021.
Basis of expected benefit	Currently reactive voltage services are procured in the BM. This pathfinder project will consider whether a long-term contract (1+ years) or an asset solution can provide the reactive support that is needed to secure the network. The trade-off will be between short term BM options or a long-term commercial contract potentially with new market participants or a new-build solution. This pathfinder also considers options across the whole system. Breakdown of savings across the voltage pathfinders are: • Area 1: CBA to estimate constraint cost saving will be carried out as part of the option assessment. Utilisation cost saving estimated at £1.3m per year. • Area 2: Potential constraint cost saving between £12m and £33m per year; utilisation cost saving estimated at £2m per year.
How benefit is realised in the consumer bill	We will choose an optimal solution, likely resulting in a trade off in BSUoS or TNUoS but should overall be net better off regarding total spend. This will result in consumer savings as both BSUoS and TNUoS are passed through to the bill.
Assumptions	We assume that any reduction in BSUoS,and TNUoS gets passed through to consumers.

13.Network Options Assessment

Consumer Benefit Outcome

Activity	The NOA provides an annual decision on what investments to progress or not progress in the next 12 months. This is based on an optimal set of solutions which need to be delivered at the correct time to provide the most efficient and economic overall consumer solution.
Role	4. Supporting competition in networks
Key Forward Plan Deliverables	• Metric 15 – NOA consumer benefit • Enhanced communication (NOA)
Delivered and future benefit	Up to £2.67bn avoided dis-benefit over a 40-year rolling period, updated yearly. In the 2018-19 NOA we recommended to proceed on £59.4m of investment options, these recommendations ensure the network will have the reinforcements needed at the correct time. If these recommendations do not proceed (hence a 12-month delay in getting an optimal set of recommendations) the consumer would lose between £1.85bn and £2.67bn of value. This loss of value is avoided by ensuring we have the correct decisions for the next 12 months to make sure we have the correct network in the future. Between 2016 and 2018, the NOA's have recommended to spend £133m and defer £45m of investment options to date.
Basis of expected benefit	The NOA is a complex analysis. We use market optimisation software to identify how and where the latest FES impact the transmission system and forecast the operational cost to manage this. We systematically look to alleviate congestion on the network with solutions can be either asset investments or commercial management of the network. We time the delivery of these solutions to provide the most benefit. The single year regret recommendation compares the optimum way to proceed in the coming year against the least optimum way. The regret value is the most expensive loss to the consumer across all scenarios if the least optimum path were taken when compared to the most optimum.
How benefit is realised in the consumer bill	Network constraints are managed and paid through the BSUoS charge, levied on system users and passed through to the end consumer. Network investments are paid for through the TNUoS charge, paid by system users and also ultimately paid by the end consumer. By recommending the optimal asset investment options, we optimise the charges that are passed onto the consumer. We will only recommend investments which reduce BSUoS by more than the corresponding increase to TNUoS, so that the net cost is kept to a minimum.
Additional non-monetary benefit	By facilitating timely connections, we are allowing generation to connect earlier than may have been the case before the NOA process was installed. Much of the new generation connecting to the network is low-carbon.
Assumptions	The main assumption is that without the NOA, network investment would be uncoordinated and not timed in the best interest of the consumers. Further to this we are unbiased in what needs to be delivered and by when. We are agnostic as to whether options are build solutions, commercial solutions or neither.

14. The Connection and Infrastructure Options Note process

Consumer Benefit Outcome

Activity	When an interconnector or an offshore windfarm apply for connection to the transmission network a choice of connection locations is possible. Some of these locations could have a significant impact on network congestion. We complete a CBA to make sure the best overall solution is delivered for the consumer. This could be connecting to another substation outside of a congested zone. This is known as the Connection and Infrastructure Options Note (CION) process.
Role	4. Supporting competition in networks 1. Managing system balancing and operability
Key Forward Plan Deliverables	• Enhanced customer experience • Metric 1 – Balancing cost management
Delivered and future benefit	Between £1bn-£2bn over 25 years from now onwards.
	The number of connection applications is determined by the energy market and each individual application will have its own assessment. Since 2017 the average overall reduction in consumer costs through CION assessments is £260m per application, between four to eight applications per year.
Basis of expected benefit	We create benefit by ensuring the connection location is optimal in the interests of the consumer. For example, a windfarm or an interconnector would want the lowest cost of connection, however this could have a high congestion impact and for a slightly increased connection cost a large reduction in congestion is possible. We model potential future congestion costs with and without the new connectee at various different locations and the lowest overall cost solution is provided.
How benefit is realised in the consumer bill	Network constraints are managed and paid through the BSUoS charge, levied on system users and passed through to the end consumer. Network investments are paid for through the TNUoS charge, paid by system users and also ultimately paid by the end consumer. By recommending the optimal overall solution, we optimise the charges that are passed onto the consumer.
Additional non-monetary benefit	We ensure we can facilitate the energy market and renewable generation by minimising the curtailment of generation.
Assumptions	• There are other cost-effective options available to connect the new system user. • If the developer's preferred choice is the best overall solution no additional SO benefit is recorded.

Consumer Benefit Outcome

15.The Strategic Wider Works process

Activity	When a TO investment hits certain trigger levels (£50m for Scottish Hydro Electric Transmission (SHETL), £100m for Scottish Power Transmission (SPT), £500m for NGET) a special regulatory process[39] is triggered which scrutinises the options to deliver the investment. We perform a cost benefit analysis which considers the network impacts of the investment. This is known as the Strategic Wider Works (SWW) process.
Role	4. Supporting competition in networks 3. Facilitating whole system outcomes
Key Forward Plan Deliverables	• Enhanced customer experience • Metric 1 – Balancing cost management
Delivered and future benefit	Between £202m-£404m per year from now onwards, with the benefits realised over 40 years.
	The number of SWW applications is determined by the TOs and each individual application will have its own assessment; there are on average 2-4 applications per year. Since 2017, the average overall reduction in consumer costs as a result of the SWW assessment is £101m. The benefit is calculated by taking the difference between the 1st and 2nd best option.
Basis of expected benefit	We create benefit as we make sure the chosen option is in the best interests of the consumer. For each investment has multiple options of various sizes, which are delivered in multiple different years. Our CBA makes sure the correctly sized option is delivered at the correct time, this is done by forecasting congestion costs and analysing the impact of each options vs the capital expenditure.
How benefit is realised in the consumer bill	Network constraints are managed and paid through the BSUoS charge, levied on system users and passed through to the end consumer. Network investments are paid for through the TNUoS charge, paid by system users and also ultimately paid by the end consumer. By recommending the optimal overall solution, we optimise the charges that are passed onto the consumer.
Additional non-monetary benefit	We ensure we can facilitate the energy market and renewable generation by minimising the curtailment of generation.
Assumptions	Without us, the process would not consider the network impacts of the investments, and with our scrutiny the consumer will get the best overall solution.

[39] https://www.ofgem.gov.uk/ofgem-publications/125277

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How our plan has evolved

How our plan has evolved

Below we have provided an overview of the feedback we received and how this has been incorporated into our plans. During the consultation, we received 18 responses, which we have published on our website here: https://www.nationalgrideso.com/about-us/future-electricity-system-operator. Given the level of feedback, where appropriate, we have grouped similar feedback together and how we respond to this feedback.

Overarching feedback

Theme of feedback	Stakeholder feedback	Our response
Exceeding vs baseline	Significant number of our stakeholder provided robust feedback on our assessment of baseline vs exceeding.	We appreciate the time and effort stakeholders have taken to consider this. We have reviewed throughout and made changes in some cases. Where we haven't' changed we have endeavoured to provide more explanation and detail in the Role chapters
Innovation funding	A number of stakeholders commented on the activities within the Forward Plan that work which are funded through innovation.	Please see Appendix A for more details of the activities within the Forward Plan which have innovation funding.
New deliverables	Throughout the roles we have received suggestions for new and additional deliverables.	We welcome these ideas, where possible we have incorporated this changes into our plans. We also recognise that this is two-year plan and we will continue to reflect on this feedback during this year or as part of the update for 2020-21.
Performance reporting	We received comments from some stakeholders regarding the ESO performance reporting – suggesting that it should be reviewed for a balance of transparency and accessibility. There was also some suggestion that the ESO report on its internal expenditure	During 2018-19, we have continued to review our reporting under the 2018-21 Incentives Framework looking at the transparency and accessibility of the information we provide. We feel that we have made significant improvements and will continue to review how we can best present our performance. We would also note that all financial reporting for NGESO is regulated through price control arrangements and reported via the Regulatory Reporting Pack and visible on Ofgem's RIIO website.
Expertise	One stakeholder indicated that the ESO should provide appropriate expertise to external events and give more attention to collaborative working	Our Forward Plan is shaped by our mission which highlights that we deliver value for consumers first and foremost, while also ensuring that we build and maintain trusted partnerships

Theme of feedback	Stakeholder feedback	Our response
		with our customers and stakeholders. Attendance at external events and collaborative working are a key part of delivering this consumer value.
Consumer benefit	We had comments from stakeholders regarding the measurement of the consumer benefits we will deliver and the risk that we are prioritising consumers over the next two years, at immense cost to future consumers	Our Forward Plan is our commitment to consumers and industry for 2019-21; we believe that the activities that we are targeting deliver most benefit for consumers today and in the future by supporting the transition to a low-carbon, decentralised energy landscape. We optimise across BSUoS and TNUoS linking our balancing decisions with our Network Options Assessments (NOA) so that in the long-term the economic and efficient outcomes are being driven when planning, developing and investing in the network
Achieving 2050 zero-carbon	One stakeholder commented that extent of the change in the industry to achieve a zero-carbon 2050, and the long operational life (40+ years) of major capital equipment in the industry, mean that all new investment should be very low or zero carbon. With the suggestion that the ESO should take this into account in its procurement of balancing services	We support new providers and technologies to enter and compete in the existing and new markets basing our decisions on the technical capabilities of providers. We work innovatively to design novel solutions which ensure the system can operate safely and securely both now and in the future with large levels of intermittent and non-synchronous generation running. We are committed to being ‘technology neutral’, as market participants already have environmental costs priced into their products and services. We will not choose to procure from providers based on the fuel they use to generate power.

Role 1 – Managing system balance and operability

Theme of feedback	Stakeholder feedback	Our response
Forecasting	We encourage the ESO to further investigate how they can provide reassurances to industry of the accuracy of the Forecasts, notably BSUoS. We would encourage the ESO to publish data accuracy information, giving a quantified confidence level, along with target to meet going forwards.	We are currently running a strategic project to deliver new advanced forecasting capabilities through employing new technologies in all our forecasts. We are in the process of reviewing current datasets used to produce forecasting models and track performance and are acquiring new datasets to allow improved modelling activities. We are working with selected DNOs to access generation metering information at distribution level. We have made improvements in our BSUoS forecasts and we are seeking new and good quality data to develop this. We welcome suggestions in this area. Alongside this we are looking at our own assumptions and to support this, we would like to move to two-way data transfer with stakeholders.
Information provision and insights	• We would encourage the ESO to reduce the publication timeframes of the Operational Insight documents. For example, Daily Balancing Cost reports must be published as soon as possible after day closure. • We strongly recommend that the ESO takes forward a consultative approach in regards to all insight documents, where they apply ongoing stakeholder engagement and feedback to adjust the data and information to remain relevant to needs. • Regarding transparency, this should include system needs in the short and medium term, ESO decision making	We agree with the desires and intent behind the feedback; want to continue to improve the visibility of information; we will keep all options under review as we work towards our long-term vision.
Transparency	The only way that NG ESO can help balancing services providers inform their own investment strategies, and commercial and operational plans, is by duly addressing the range of existing and competition-damaging bilateral contracts that are still in place. The reluctance of NG ESO to share more information on the terms of bilateral contracts gives the impression that the ESO is tied to expensive and uncompetitive contracts that were signed in the past and cannot be terminated. This is seriously undermining not only	We are moving away from bilateral contracts and increasing transparency under role 1. We are committed to new markets under role 2. We are using the *Operability Strategy Report* to guide and prioritise enduring market solutions.

Theme of feedback	Stakeholder feedback	Our response
	competition but also the possibility for market participants to rely on a market signal that truly reflects the costs incurred by the ESO to balance the system.	
IS systems	European Network Codes – whilst the detail was not available at the time RIIO-T1 was established, the need for change associated with these was known at that time and hence would question if this is exceeding baseline	We have changed this to meeting expectations.
	The delay in implementing Electricity Balancing System (EBS) is a disappointment and should be resolved. We are surprised therefore that resolution of this work is not included in this Forward Plan. We would ask that a specific deliverable is added that commits National Grid to resolving all remaining issues and implementation by Q1 2019/20 at the latest, if not already achieved by April 2019. This should be considered as meeting the baseline performance.	We are delivering work under the Balancing Programme looking at the Future of Balancing. This will deliver incremental process and system changes that keep pace with the changing environment.
	On the upgrade of information systems, we urge National Grid to complete the roll-out of the ASDP as soon as possible: we understand that the prototype is being utilised to dispatch a small number of FR providers. The wider roll-out should be implemented swiftly.	We will continue to develop this platform in an agile way in order to realise the potential capability.
Information provision scorecard metric	We think this is business-as-usual and having a performance metric based on timely publication of information is not ambitious and should not be a measure of performance.	We think it is positive and useful to share this information;, we agree that this is baseline performance.
Balancing cost management metric	Historic data should not be used to measure performance and could result in easily achievable targets. For example, due to changes in system infrastructure or generation mix, a large reduction in balancing costs could be realised the following year. Performance benchmarks should be reviewed annually, considering any changes to drivers of balancing costs.	The benchmark is intended to be a baseline of costs. Our performance will be measured against the consumer benefit we are able to deliver rather than our performance against this benchmark.
	With respect to HVDC availability, can the ESO provide Scottish constraint costs figures with the HVDC link in service included, and	The adjustment figures in the plan is a benchmark, we will report the actual benefits as part of other requirements.

Theme of feedback	Stakeholder feedback	Our response
	without, so that clarity on how any reduction is achieved becomes evident.	
Energy forecasting accuracy metric	The ESO should be striving to improve their forecasting accuracy as part of business-as-usual activities. Using historic data to measure performance in this way could mean that a minor improvement in accuracy is graded as "Exceeds benchmark" performance. Seasonal targets should be ambitious and bespoke. We propose the following Performance Benchmarks: • Exceeds benchmark: 9 out of 12 months meet the target • In line with benchmark: 7 out of 12 months meet the target • Below benchmark: less than 7 months meet the target	We are moving from seasonal targets to monthly targets which are a reflection of our historic performance and will drive us to do better than we have done in the past. We have calculated our targets by taking a monthly average over the past three years. This allows for seasonal variability whilst smoothing out the possibility of unusual weather happening in a particular month. In this way the methodology for setting the targets is both transparent and fair. We have revised our benchmarks as follows: • Exceeds benchmark: 9-12 months meet the target • In line with benchmark: 6-8 months meet the target • Below benchmark: less than 5 months meet the target

Role 2 – Facilitating competitive markets

Stakeholder	Stakeholder feedback	Our response
Amount of regulatory and code change	There is a large amount of regulatory change underway currently and this is unlikely to change over the timescale of this Workplan. As CUSC Secretariat, the ESO is under a lot of pressure but it is clear that the teams supporting the CUSC, CFF, and other issues like BSUoS reform need more resources and detailed expertise. CUSC Mods that are considered lower priority move incredibly slowly, meaning the defects that are preventing lowest costs for consumers are sustained. As an example, CMP298 was proposed in April 2018, for April 2019 implementation, and has its third Workgroup meeting in March 2019. We acknowledge that the Code Governance team has increased FTE compared to 2017/18, but this is not enough, especially with the upcoming Energy Codes Review. Furthermore, we have experienced a marked difference between Elexon support for Modifications under the BSC and NG support for CUSC modifications. Elexon have a focus on developing and retaining staff with detailed industry knowledge. We believe that NG could do more in developing these skills in the CUSC secretariat and ensuring they are retained so that CUSC modifications can be fully supported with expert analysis.	We recognise the concern from some stakeholders that de-prioritised modifications are not progressing as interested parties may wish. However, we are also seeing a significant increase in the number and complexity of modifications and (even if the ESO had a team to support every modification) we are witnessing that the industry as a whole is struggling to support all modification discussions. For example, we are seeing quoracy issues with our working groups, As such we are working to ensure that our prioritisation process is fit for purpose and transparent. Our Forward Plan sets out how we will increase support for modifications especially as a critical friend through governance surgeries and increased opportunities to discuss with our governance experts.
Product Roadmaps	• Whist we're supportive of the SNAPS process and proposed deliverables, few substantive actions have been completed and some plans have been significantly delayed. • In relation to Principle 3, we are concerned there is not enough justification of why certain activities are deemed to meet or exceed the baseline expectations.	We understand parties' concerns over delays to a small number of the deliverables committed to as part of the *Product Roadmaps*. We have communicated the reasons for these delays through the regular Forward Plan progress reports as well as our monthly balancing services newsletter. Regarding the delivery of a day ahead auction for frequency response, this will be investigated through the auction trial deliverable. The trial will last for two years, and therefore the earliest date for delivery of a day ahead market is beyond the horizon of the 2019-21 Forward Plan. We believe that the benchmark for whether a deliverable is exceeding baseline is driven by the scope and difficulty of the task, and not just whether it was achieved in a certain time.

Stakeholder	Stakeholder feedback	Our response
		These tasks represent fundamental reform to the way the Great Britain system and markets operate and their delivery should be viewed as such. We agree that there needs to be more clarity on why certain activities are categorised as exceeding or meeting baseline; please see within the role chapter where we have provided more detail on how this activity is exceeding baseline expectations.
Wider access to BM	We note there are no Exceeding Expectations deliverables under Wider Access to the Balancing Mechanism. Since this is a key element of the future of the BM given the changes in scale of generation, it seems counterintuitive that the ESO are not pushing themselves to improve BM access.	We have enabled multiple units to enter the balancing mechanism through existing industry arrangements (Supplier route) ahead of BM Wider Access. This has allowed aggregated distributed assets to access the balancing mechanism. Since the introduction of the first aggregated unit in August 2018 we have in excess of 50MW from aggregated units (as of March 2019). Recognising the importance of wider access to the BM we have recently introduced a distributed resource desk to enable power system engineers to instruct smaller users. Since its launch we have received very positive feedback from industry and dispatch has increased over 100%. We are currently investigating bulk dispatch which, if implemented, will further improve the process.
Intermittent generation	We agree with the categorisation of the 5 key deliverables; however we believe the publication of the strategy on flexibility from intermittent generation needs to be delivered before Q4 2019/20. That strategy will be critical to providing confidence in the future availability and viability for new renewables to be developed (particularly those that would be operated on a merchant only basis). Given the consumer benefits that will be lost and broader impacts on decarbonisation targets, publishing the strategy (including the long-term vision) must be made more of a priority to provide confidence and certainty to current and future investors.	Please refer to our role chapter where we have provided greater detail in response to this feedback.
Power Responsive	We propose that National Grid set out explicitly how it will move to open, competitive procurement for all products; as far as possible. The deliverable 'Deliver innovation projects to unlock demand	We have set out the steps which we will take to reform our products and markets through the *Product Roadmaps* and in the Forward Plans. The deliverable on supporting innovation

Stakeholder	Stakeholder feedback	Our response
	flexibility' is currently very vague stating only that the ESO will work with stakeholders 'to unlock barriers to entry and maximise opportunities for accessible, competitive markets'.	projects is not intended to capture all this development work, revisions with the role chapter have been made to clarify this.
Black start services	We also believe that work on procuring BM Wind for Black Start services could also be brought forward with further collaboration from wind energy developers. We are also concerned that the current Black Start Procurement Event may create precedents in contractual frameworks or product design that may preclude the conclusion of work on getting other technologies into Black Start.	We are committed to running a competitive market for the procurement of Black Start Services for the South West and Midlands. This current procurement exercise has identified a service requirement for April 2022. We plan to roll this approach out to the other zones. At the moment the use of non-traditional technologies is being investigated through the NIA/NIC projects. As learnings from these projects become available we will evolve our procurement approaches to broaden participation where appropriate. If, through the NIC project, we identify an alternative approach to system recovery, we will outline revised requirements and ensure that all potential providers have ample opportunity to participate.
Metric 5	We agree that a survey is a good way to quantify customer satisfaction. However, we would suggest the following more ambitious metrics: • Exceeds benchmark: Average above 4 out of 5 • In line with benchmark: Average between 3-4 out of 5 • Below benchmark: Average less than 3 out of 5	We have updated the metric to reflect more ambition in the exceeding benchmark category. However, without any historic information we believe it is appropriate to initially choose 50% for In Line, and keep this under review through the Forward Plan period. We have changed the benchmarks to the following: • Exceeds benchmark: Average of 4 and above • In line benchmark: Average between 2.5-4 • Below benchmark: Average less than 2.5
Metric 6	For the Metric 6 "Reform of measuring Balancing Services market", it is not clear who will define whether there are barriers to entry in Part 1 and whether that is relevant users or the ESO. We would also prefer clarification between Amber and Green. Part Two measures the direction of travel but does not given any target by which the ESO's performance could be measured. We suggest that the spend on bilateral arrangements should reduce from its current percentage	For part one, the barriers to entry are those identified with the industry through the *SNaPS* consultation, and the *Product Roadmaps* list the deliverables that are required to alleviate these barriers. For part two, as per our licence, we operate the system in an economic and efficient way. There are circumstances in which procuring bilaterally delivers the most value for consumers (for example, a bilateral constraint contract will be cheaper than

Stakeholder	Stakeholder feedback	Our response
	by a predetermined amount or the number of parties engaged in bilateral contracts reduces.	continually taking a large number of BOAs through a period of constraint). A metric which created a financial incentive on the ESO to avoid bilateral contracts could increase cost to consumers and would not align with our licence obligations.
	We suggest that the spend on bilateral arrangements should reduce from its current percentage by a predetermined amount or the number of parties engaged in bilateral contracts reduces.	For part two, as per our licence, we operate the system in an economic and efficient way. There are circumstances in which procuring bilaterally delivers the most value for consumers (for example, a bilateral constraint contract will be cheaper than continually taking a large number of BOAs through a period of constraint). A metric which created a financial incentive on the ESO to avoid bilateral contracts could increase cost to consumers and would not align with our licence obligations.
Code administrator: stakeholder satisfaction metric	Whilst supportive of efforts to measure stakeholder satisfaction of code administration services, we believe that the basis for measurement (Ofgem CACoP survey) is a poor metric.	We have provided more detail on the benchmarks associated with this metric within the role chapter. We will measure our performance in this area by the CACoP survey, wider stakeholder surveys and delivery of outputs.
Charging Futures metric	Ambitious bespoke targets should be set for each period rather than just using the initial survey at the beginning of the year to set the benchmark	Our success as lead secretariat should be judged against our ability to maintain the overall scores for these measures throughout the year. This will be calculated by periodically repeating the survey throughout the year and averaging these scores. These scores will then be compared against the initial baseline score.
Year ahead forecast vs outturn annual BSUoS metric	Due to its market position and depth of resource, the ESO is best placed to produce a robust BSUoS forecast. It's appropriate the ESO is incentivised to forecast BSUoS as accurately as possible, but this metric lacks ambition.	An annual BSUoS forecast is vital for those parties seeking to price long-term products such as electricity suppliers providing fixed price supply contracts to domestic consumers. The better the forecast the lower the risk premia that need be added to the supply contract and as a result the lower the cost for the end consumer. The nature of BSUoS and the impact that significant and unexpected events during the year can have on the cost of system balancing means that there is significant uncertainty in an annual forecast. An event such as £18m spend on margin over 3 days, or significant fault outages like

Stakeholder	Stakeholder feedback	Our response
		HVDC can cost tens of millions of pounds. Our incentive performance could easily be lost by an event could happen on day two of the incentive period. It is this level of uncertainty that has informed our development of thresholds across which our performance will be measured.

Role 3 – Facilitating whole system outcomes and Role 4 – Supporting competition in networks

Theme of feedback	Stakeholder feedback	Our response
Regional development programmes	We are interested to see how the work with ongoing Regional Development Programmes will develop and are surprised that there are limited deliverables to be shared with stakeholders in this area. We would have expected that the ESO would be delivering lessons learnt documentation as part of delivering the desired outcome, in order to capture what does and doesn't work and in what circumstances and suggest that this is included into the work plan. As a DNO that has not been involved in a designated RDP to date, we would welcome the opportunity to review and comment on the productionised process proposals.	Whilst we are now in the delivery phase of our initial RDPs, until we have experience of how things work in practice it is difficult to distil lessons learnt. However, it has always been our intention to do that, and to share that learning with industry so that we can collectively pursue best-practice through appropriate channels. We have previously noted that this would form an input into relevant work within the ENA's Open Networks project, and would also guide our collaborative approach to future RDPs. Please see within the role chapter where we have provided more detail of the deliverables.
DER procurement	We would like to see more ambition and pace in the ESO's plans for enhanced systems to facilitate procurement of balancing services from Distributed Energy Resources (DER). We would ask that more specific and measurable outputs and outcomes are proposed for this deliverable.	The publication of the draft Forward Plan 2019-21 coincided with detailed planning of the project work to deliver these systems. We will add as much information on specific milestones that we have available to us when we publish the final version of the Forward Plan. We will work with our IS team to ensure plans remain as ambitious as possible whilst maintaining an appropriate balance with the ability to deliver against them.
Pathfinder projects	We urge the ESO to duly consider commercial solutions with a greater than twelve month horizon. It is important they are properly costed and the cost/benefit is made clear to the consumer.	As part of the pathfinder development, we have reviewed DNO solutions in the first phase of our assessments. This is part of the learning by doing approach. We will be running a RFI to call for other service providers to give their options as part of phase two. All options will ultimately be assessed against each other in a non-preferential way defined in our assessment principles. These options will be to meet long-term system needs. The assessment principles of any tenders or details of our cost benefit process will be visible to customers through our tender packs or NOA methodology.
NOA: Enhanced communication	The 'need' should be communicated in such a manner, with appropriate tools and data to allow market participants to propose solutions and drive innovation.	A key deliverable for 2019-21 is our NOA: enhanced communications; this includes the communication of needs to assist a broader range of participants to get involved in the NOA process.

Theme of feedback	Stakeholder feedback	Our response
		We are looking to achieve the best whole system outcomes through the NOA and its processes are being developed through knowledge gained in out pathfinder projects to ensure all options can be evaluated fairly through the CBA.
Whole system, unlocking cross-boundary solutions metric	Measuring the DER MW that have signed contracts to connect to the distribution network in two specific regions does not equate to the value delivered to consumers or demonstrate whole system thinking. Any metric should be able to clearly quantify the benefit to consumers. The value of avoided network investment would be a more tangible measure.	Using a metric based around the value of avoided investment is an interesting proposition, which we will look at. We note however that one of the benefits of the current metric is in its simplicity, an 'avoided investment' metric would require several assumptions to be made and, for connections in the same area, might ultimately have the same cost implications for each, and hence boil down again to a simple 'per MW connected' calculation.
	This metric should be expanded to include: • Volumes that have been enabled by the RDPs. • Volumes contracted to participate in transmission constrain management.	Adding in volumes contracted to participate in transmission constraint management is something that should be reasonably straightforward to achieve. We will consider its inclusion in the plan.
	In terms of the measure you have proposed for this section, whilst we agree that it is appropriate in terms of proving that it actually works requires the connection of DER to the distribution network, yet providing support for balancing services however as there are no quantities targeted (at the moment) the metric is not SMART.	We have deliberately avoided setting targets on things such as volumes of connected MW, as we do not consider it appropriate for us to have an explicit incentive to target DER connections in constrained areas. The aim is to remove blockers and promote continued efficient management of transmission constraints.
Connections agreement management metric	• It's not clear what the purpose of this metric is. We would welcome additional context from the ESO regarding why agreements need updating following TO works and the impact of such changes on generators. • The metric 14 to reduce variations in post contract offers removes those variations attributed to TO's. We would be delighted to support this initiative but the ESO has historically not been able to provide feedback or evidence of where we may have opportunities for performance in this area. It would be of benefit to	We have provided more detail on this metric within the role chapter. We recognise the importance of transparency of SO-TO engagement will continue to review options in this area.

Theme of feedback	Stakeholder feedback	Our response
	customers going forward if this feedback could be provided in a way that can facilitate improvement in the offer process.	
Metric 16 NOA: enhancing communication	There is however the risk of double counting: for example, if an initiative is brought forward by the ESO to address a potential voltage issue. Given ESO's cooperation with other agencies around network development, it may be hard to judge whether an option was initiated by the ESO.	We will report transparently and clearly to Ofgem and the Performance Panel which will mitigates the risk of double counting.

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