Department for Business, Energy & Industrial Strategy

GB Implementation Plan

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Contents

Introduction

This implementation plan applies to the electricity market in Great Britain (GB) and is structured as follows:

- **Part 1** provides an overview of the resource adequacy concerns identified in GB;
- **Part 2** describes the operation of the GB electricity market, and includes an overview of the GB Capacity Market (CM) mechanism;
- **Part 3** gives a description of the market distortions and failures, which led to the introduction of the GB CM;
- **Part 4** describes a range of action the UK Government has pursued - and continues to pursue - to address the market failures; and
- **Annex A** lists the market reforms being pursued to continue to address these market failures and the timeline for implementation of these measures.

Resource adequacy in Great Britain

Like many of its European counterparts, the UK faces an unprecedented challenge: it needs to maintain security of supply while decarbonising its electricity supply, against a background of the closure of significant amounts of existing generation. Several countries, including the UK, have introduced capacity mechanisms in response to concerns about continued security of supply in these circumstances.

In 2014 the GB Capacity Market (CM) was introduced following the identification of resource adequacy concerns and associated failures contributing to these concerns in the GB electricity system. The UK Government's State aid notification in 2014 identified:

The scale and nature of the resource adequacy concerns in GB citing: the reliance on secure energy supplies, the rapid closure of significant amounts of existing capacity, and the increasing proportion of intermittent generating capacity as progress is made towards decarbonisation targets;

The market failures present in the GB electricity market which mean it is unlikely to deliver the efficient level of capacity in the absence of intervention, namely: that reliability is a public good, prices may not rise high enough to justify sufficient new build, and the investment case for back-up and peaking plants is increasingly risky as it is dependent on price spikes in scarcity conditions which may not arise.

The Commission's State aid decision of 2014[1] found that the proposed GB CM was both: compatible with EU State aid rules; and necessary given the resource adequacy concerns identified by the UK Government, which were broadly consistent with the findings published by the ENTSO-E Systems Adequacy report.[2]

In November 2018, following a challenge to the Commission's 2014 decision, the General Court of the European Court of Justice annulled the Commission's decision on procedural grounds. Consequently, the Commission conducted an in-depth investigation to reassess the compatibility of the scheme with EU State aid rules. To assist with the investigation, the UK Government submitted updated information on resource adequacy concerns in Great Britain and on efforts to address the market failures identified in the original 2014 notification. This information outlined that:

- Analysis undertaken by the UK Government, as well as a separate analysis provided by the CM Delivery Body, National Grid: Electricity System Operator (NG:ESO), demonstrates the ongoing need for the CM. Specifically, it demonstrates that the absence of the CM would impact GB's security of electricity supply with a Loss of Load Expectation (LOLE) above the reliability standard of 3 hours/year in all years from 2019/20;[3] and

- The market reforms completed so far are not sufficient to achieve security of supply without the CM. Other market reforms likely to be necessary to ensure security of supply

[1] https://ec.europa.eu/competition/state_aid/cases/253240/253240_1579271_165_2.pdf

[2] https://docstore.entsoe.eu/Documents/TYNDP%20documents/TYNDP%202014/140602_SOAF%202014-2030.pdf

[3] The Loss of Load Expectation represents the expected number of hours per year in which supply is expected to be lower than demand under normal operation of the system. By normal operation of the system we mean in the absence of intervention (e.g. voltage reduction) by the System Operator.

in the absence of the CM are not yet complete yet. Given the electricity market is continuing to evolve, the future impact and effectiveness of these reforms remains highly uncertain. However, as the market develops and a more cost-reflective electricity price evolves, there may be scope to withdraw the CM. The UK Government assesses annually whether a capacity auction is needed (see below) and conducts a full review of the CM, including whether it is still needed, every five years.

In October 2019 the Commission confirmed that the GB CM scheme covering the period 2014-2024 complies with EU State aid rules, and that the scheme is necessary to guarantee security of electricity supply in Great Britain until at least 15 December 2024.[4]

In addition to the specific analysis produced to support re-notification of the GB CM, each year, NG:ESO carries out extensive analysis on security of supply in GB through the production of an Electricity Capacity Report (ECR).[5] The ECR provides an assessment of resource adequacy in GB. These reports summarise the modelling analysis undertaken by NG:ESO in its role as the Electricity Market Reform (EMR) Delivery Body to support the decision made by the Government on the amount of capacity to secure through the annual CM auctions to meet the reliability standard.

This analysis is scrutinised by a Panel of Technical Experts (PTE) and the energy regulator, Ofgem. The PTE is an independent advisory group appointed by Government to advise on technical matters relating to implementation of the CM. In particular, the PTE produce an annual report providing an independent view on the ECR to assist the Government in setting the parameters for the CM auctions, and recommendations to help improve the ECR modelling in the future.[6] The terms of reference for the PTE are publicly available.[7] Ofgem, in their role as the regulator, undertakes an annual performance review of the demand forecasting provided as part of the ECR.[8]

The ECRs provided by NG:ESO have recommended that capacity be procured each year through the CM auctions in order to meet the reliability standard. The decision on whether a CM auction is needed each year is informed by the ECR provided by NG:ESO, with the decision on whether to hold an auction made by the Secretary of State.

Recent ECRs[9] have advised that it is necessary to secure capacity through the CM to continue to meet GB's reliability standard.[10] Currently, the UK Government plans to hold the following CM auctions in early 2021:

- 2 March 2021 T-1 auction for delivery year 2021/21; and
- 9 March 2021 T-4 auction for delivery year 2024/25.

Alongside the introduction of the CM, the UK Government has pursued - and continues to pursue - a range of actions to improve the functioning of the GB electricity market, such as

4 https://ec.europa.eu/commission/presscorner/detail/en/IP_19_6152
5 https://www.emrdeliverybody.com/CM/Capacity.aspx
6 The PTE's most recent publication is available at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/816012/Panel_of_Technical_Experts_report_2019.pdf
7 https://www.gov.uk/government/groups/electricity-market-reform-panel-of-technical-experts
8 https://www.ofgem.gov.uk/sites/default/files/docs/2015/09/decision_on_revenue_outputs_and_incentives_for_nget_plcs_roles_in_electricity_market_reform_0.pdf
9 https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Electricity%20Capacity%20Report%202019.pdf
10 NG:ESO recommended a target capacity of 0GW for the T-1 auction for the 2020/21 delivery year, however they did recommend procuring capacity for the associated T-4 for the 2020/21 delivery year.

increasing energy efficiency, supporting increased interconnection, and supporting the work of Ofgem to reform imbalance settlement arrangements to improve price signals (Part 4).

Description of the GB Electricity Market

The wholesale market

Until 1990, the UK electricity market was nationalised, with generation, transmission, distribution and retail operated by publicly owned monopolies in Scotland, and England and Wales. These arrangements were successful in expanding electricity generation and transmission capacity to meet rising demand after the Second World War, but by the 1970s they began to be criticised for their inefficiency. To increase efficiency and competitiveness, the electricity market in England and Wales was privatised in 1990, with the establishment of a wholesale electricity market in the form of a gross mandatory pool into which all electricity supplied from plants over 100MW had to be sold.

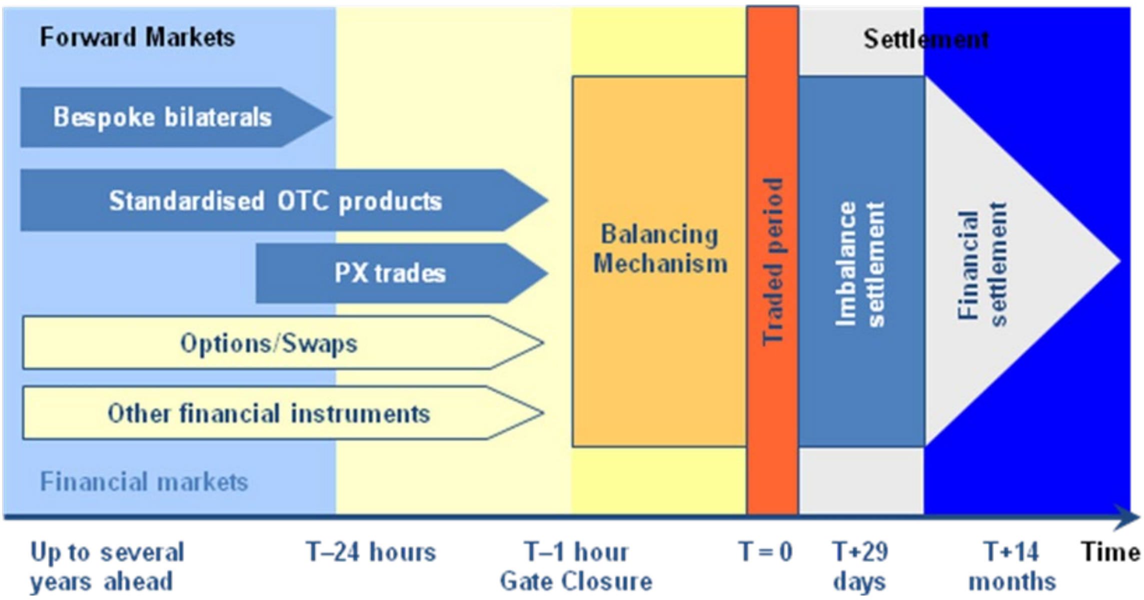
Since the theoretical profit maximising strategy of a generator would be to offer energy into the pool at the marginal cost of generating that energy, there would not necessarily be enough profit from the new arrangements for generators to cover their initial investment costs. For this reason, there was a separate payment for capacity for each unit declared available to generate. This payment was based on the probability and value of lost load and was paid to all generators declaring themselves available, in addition to any revenues they earned from selling energy into the pool if dispatched.

Although an important step towards a competitive liberalised energy market, the pool was criticised during its 11-year life-time because its design could be exploited by the market's two dominant participants at the time. This led to further reform.

New Electricity Trading Arrangements (NETA) came into force in March 2001, covering England and Wales. On 1 April 2005, changes to harmonise electricity trading across GB (i.e. England, Wales and Scotland) came into effect with the introduction of a single set of wholesale electricity trading and transmission arrangements known as BETTA (British Electricity Trading and Transmission Arrangements). BETTA is based on bilateral trading between generators, suppliers, customers and traders, and participants self-dispatch rather than being dispatched centrally.

Under BETTA, contracts for electricity are agreed in forwards and futures markets from several years up to 24 hours ahead of a given half hour delivery period. Short-term power exchanges and energy brokers give participants the opportunity to fine tune their contract positions from 1 to 24 hours before delivery. All the deals are bilateral and are settled at the price registered on the power exchange or agreed bilaterally or through a broker. Figure 1 provides an illustration of the trading arrangements under BETTA.

Figure 1: Current trading arrangements under BETTA



Source: Elexon.

Under BETTA, the wholesale electricity price rewards generators for their electricity and capacity, and investors must decide to invest based on their expectation of recovering the costs of this investment through selling electricity in the wholesale electricity market.

There are no formal or informal rules that limit a generator's ability to freely price its offers in the wholesale market. There may be informal, de facto limits in both wholesale and balancing markets, as in theory no one would go higher than the value of lost load and no one would go lower than the inverse of the value of the greatest subsidy payment associated with generating. In addition, we are not aware of any rules or provisions which require Transmission System Operator's (TSOs) to release generation reserves to the market when market prices rise above certain thresholds.

Capacity Market

The Commission's State aid decisions of 2014[11] and 2019[12] provide a description of the GB CM mechanism, which included the roles and responsibilities of the organisations involved in its implementation and administration, and how it operates. A brief summary is given below.

Territorial limit

The CM operates alongside the GB wholesale electricity market, i.e. covering England, Wales and Scotland. Northern Ireland is part of a separate electricity market - and capacity mechanism - covering the Republic of Ireland and Northern Ireland.

[11] https://ec.europa.eu/competition/state_aid/cases/253240/253240_1579271_165_2.pdf
[12] https://ec.europa.eu/commission/presscorner/api/files/document/print/en/ip_19_6152/IP_19_6152_EN.pdf

Eligibility and pre-qualification for a capacity auction

The CM operates on a technology neutral basis. Generation capacity - both existing and new, storage, Demand Side Response (DSR), and interconnected capacity (from the delivery year 2019/20) are able to participate. Capacity providers participate in the CM on the basis of 'Capacity Market Units' (CMUs). A number of different generating and DSR CMU types are defined in the GB CM Rules[13] and Regulations[14], and are categorised broadly either as: a generating CMU; interconnector CMU; or a DSR CMU. It is at the CMU level at which applications for pre-qualification for a capacity auction are made, capacity agreements are held, obligations apply in times of system stress, and penalties/over-delivery payments are calculated.

Participation in the CM is not mandatory, although it is mandatory for all licensed, eligible capacity to participate in the pre-qualification process, even if it does not intend to bid. Capacity that cannot meet the eligibility criteria or is already in receipt of State aid through other measures is ineligible to bid. The purpose of the pre-qualification process is to ensure participants in the auction can deliver the capacity they offer, and the System Operator is able to adjust the amount of capacity to auction based on the volume of capacity opting out of the auction.

Any eligible capacity that opts out during the capacity auction is not exposed to penalties for non-delivery, nor is it eligible for any payment (including for over-delivery) as part of the CM. Such capacity is able to opt back into subsequent auctions and can participate in the secondary market. In the secondary market the obligation to provide capacity can be traded to be delivered by another CMU.

Establishing the amount of capacity to auction

The UK Government assesses annually whether a capacity auction is needed. This decision is made by the Secretary of State, informed by the independent ECR carried out by NG:ESO, which is scrutinised by the PTE and the regulator Ofgem. The ECR focuses on assessing the amount of capacity needed to deliver the reliability standard five-years ahead,[15] and draws upon a separate assessment by NG:ESO which looks 15 years ahead and assesses the likely evolution of future electricity demand.[16] This assessment of the amount of capacity that should be procured at auction takes into account capacity eligible to participate, capacity choosing not to participate in the CM, and ineligible capacity.

Auction process

Applicants who have successfully pre-qualified and confirmed entry into the auction, enter a competitive central auction, run by NG:ESO, four years (with a further auction one year) ahead of delivery. The auction process is a descending pay-as-clear auction, which means auction participants enter an exit bid at which they wish to leave the auction. The exit bid represents the minimum price £/kW which the participant is willing to accept to provide capacity. The auction clears when the amount of capacity left in the auction meets the auction demand curve. The clearing price is paid to all participants remaining in the auction when it clears. Successful bidders are awarded 'capacity agreements', which provide a steady payment

[13] https://www.gov.uk/government/publications/capacity-market-rules

[14] Principally, the Electricity Capacity Regulations 2014 and the Electricity Capacity (Supplier Payment etc.) Regulations 2014.

[15] The Government has a reliability standard for the GB electricity market equal to a loss of load expectation of three hours per year.

[16] http://fes.nationalgrid.com/media/1409/fes-2019.pdf

(£/kW) in return for a commitment to deliver electricity at times of system stress if called upon to do so by the System Operator. Capacity providers who fail to deliver energy when required face a financial penalty.

Secondary market

Between auction and delivery, and in the delivery year(s), participants can adjust their position through trading if they are unable to meet their obligation. This can be done either through obligation trading or volume reallocation.

Capacity providers with an active Capacity Obligation may transfer that obligation to another eligible capacity provider. The receiving capacity provider must have successfully prequalified for an auction for that delivery year, or for secondary trades for that delivery year.

Following a stress event, volume reallocation allows capacity providers who have over delivered to transfer excess output of a CMU to a separate CMU. Where a CMU has delivered more than its Adjusted Load Following Capacity Obligation (ALFCO) i.e. the seller; this CMU would be permitted to reallocate the excess output to another CMU which did not deliver all of its ALFCO i.e. the buyer. The obligation of either CMU is not changed by the trade. The Delivery Body administers this process, ensuring that limits on the volume to be reallocated are followed and controls which parties can reallocate excess output in the CM Rules.

Payment

The costs of capacity payments made under capacity agreements are met by suppliers. All licensed suppliers must pay a capacity market supplier charge to finance the costs of the Capacity Market. The payments flow from suppliers, via the CM Settlement Body- the Electricity Settlements Company (ESC), to capacity providers. Where penalties for non-delivery are paid by capacity providers, and these payments are greater than any over-delivery payments made to capacity providers, the funds flow from them, via the ESC, to suppliers.

Requirement to review

There is a statutory requirement for the CM to be reviewed every five-years to assess the extent to which it effectively delivers on its objectives, and if it remains the most effective form of intervention to address underlining market failures. This review considers the current and future role of the CM with a view to adapting its design as the market develops and removing it once the underlying market failures have been addressed. The CM is not intended to be a permanent intervention in the market. The UK Government carried out a 5-year review of the scheme for the period 2014 to 2019, and published a summary report.[17]

Balancing market: Imbalance settlement

There is a balancing mechanism[18] through which NG:ESO accepts offers and bids for electricity close to real time. This enables the NG:ESO to balance supply and demand. At ‘gate closure’, 1 hour before each half hour delivery period, generators are required to notify the

[17] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/819760/cm-five-year-review-report.pdf
[18] Details correct as of December 2019

NG:ESO of the energy they intend to deliver[19] and the expected output from each plant. Suppliers (retailers) must declare the amount that they have contracted to buy, which should be the amount they expect their customers to consume. Finally, an imbalance settlement process makes payments to and from those market participants whose contracted positions do not match their actual metered electricity production or consumption. It also settles other costs of balancing the system.

In GB we have a single imbalance price, which cannot be forecast accurately and deviates (sometimes significantly) depending on whether the system has too much or too little power (long or short) in a given settlement period. The price itself is designed to represent the value of the energy in the system, and is not in and of itself an incentive. The primary incentive comes from the variability of the price, which introduces significant 'price risk' to parties facing it. By managing their imbalance position using trading and assets, they avoid this price risk.

The single imbalance price is used to determine imbalance charges. The System Sell Price (SSP) and System Buy Price (SBP) are the 'cash-out' or 'Energy Imbalance' prices. These are used to settle the difference between contracted generation, or consumption, and the amount that was actually generated, or consumed, in each half hour trading period.

With a single imbalance price, the SBP will equal SSP in each Settlement Period. These prices are then applied to the relevant Parties' imbalances to determine their imbalance charges. Single imbalance prices seek to create more cost-reflective incentivisation. For example, without a single market price, the market price paid to parties that have reduced the system imbalance is not cost-reflective, and is inefficient because it over-incentivises parties to be in balance. The market price does not allow parties with helpful imbalances to share the cost-savings and benefits to the market. A single imbalance price addresses these concerns, because it reflects the balancing costs that are avoided too.

The imbalance settlement rules are set out in the Balancing and Settlement Code (BSC),[20] managed by ELEXON (a third party delegated operator). Parties engaging in supply, generation and trading of electricity are obliged to be licensed (with some class and individual exemptions) and the licences oblige these Parties to be signatories to the BSC.

The balancing rules are consistent across all Parties, including how a Party's imbalance is calculated, how much they must pay, by when, and how much credit they need to post.

The costs for procuring balancing services are recovered via the Balancing Services Use of System (BSUoS) charge, which is levied on parties by NG:ESO based on their market share (in MWh generated/supplied). This charge is independent of the imbalance price. Including these costs in the imbalance price would distort the signal provided by the price, and would be against Third Energy Package requirements for the imbalance price to reflect the cost of balancing energy (the Electricity Balancing Guideline Commission Regulation (EU) 2017/2196, ("EBGL"), Articles 55 and 17).[21]

As above - it would be inappropriate to levy BSUoS charges through the imbalance price under the current legislative framework.

[19] These are contracts that arise from the wholesale electricity market and are not capacity agreements under the CM.
[20] The complete balancing and settlement code documents are available at: https://www.elexon.co.uk/bsc-and-codes/balancing-settlement-code/
[21] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32017R2195&from=EN

BSUoS recovery also includes the recovery of procurement costs of balancing capacity, as referred to in Article 44(3) of the EBGL.[22] The BSC already includes a scarcity pricing mechanism in the imbalance price. The overall BSUoS arrangements were recently considered by the BSUoS Task Force.

The volumes for disconnections of customers are priced at the Value of Lost Load (VoLL) and then entered into the imbalance price in the same way as any other balancing action of a similar nature would be. This happened recently during the 9th August 2019 power outages in GB[23] which were the result of issues occurring on the transmission and distribution networks, followed by a cumulative generation loss from several plants and generators. The data is available for study. On the 9th of August the imbalance price was not significantly affected by the outage (it changed by £0.25/MWh), primarily because the actions were taken to maintain system stability rather than to contribute towards the net energy available on the system (a ‘system balancing’ action rather than an ‘energy balancing’ action). If the action had been energy balancing, then the VoLL used in imbalance pricing (£6000/MWh) would have contributed to the imbalance price calculation in the same way as any other balancing action.

The VoLL used in imbalance pricing can be updated following a review and modification process, ultimately decided on by Ofgem, following new studies on VoLL. The current price (£6000/MWh) was set following a report by London Economics for Ofgem and (as the UK Department for Business, Energy and Industrial Strategy then was) the Department for Energy and Climate Change.[24]

The same report identified an overarching VoLL value for GB of £17000/MWh. This value is used in the calculation of the GB electricity reliability standard which is currently set at 3 hours LOLE. The reliability standard is targeted to ensure security of electricity supply when determining the amount of capacity to procure at each of the CM auctions. The UK Government is planning to review the GB electricity reliability standard following the five-year review of the Capacity Market.[25]

The Commission’s opinion[26] refers to there being no fundamental reason why the two values of VoLL should differ. However, as no robust market exists for supply interruptions, VoLL cannot be observed directly from market behaviour. As a consequence, VoLL must be determined indirectly. Establishing an accurate estimation of VoLL for GB consumers is difficult and there is no single VoLL for all GB electricity consumers. It differs between different consumers and consumer types and depends on the specific context, for example between peak and off-peak, winter and summer periods, even for the same consumer.

When setting an administrative VoLL there are several considerations regarding how best to reflect consumers’ diverse preferences. The report by London Economics[24] for Ofgem provided a large range of estimates that consumers place on secure electricity supplies. The study suggested that £17,000/MWh may be a fair reflection of the average VoLL for domestic consumers and SMEs on a winter peak day. Averaging only across SMEs and domestic consumers recognises that industrial and commercial consumers are more likely to enter into interruptible contracts, and should be incentivised to do so. This evidence must also be combined with considerations, such as the appropriate balance between performance

[22] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32017R2195&from=EN
[23] https://www.ofgem.gov.uk/publications-and-updates/investigation-9-august-2019-power-outage
[24] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/224028/value_lost_load_electricty_gb.pdf
[25] See page 56, paragraph 209 of the Capacity Market five-year review: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/819760/cm-five-year-review-report.pdf
[26] https://ec.europa.eu/energy/sites/ener/files/documents/adopted_opinion_gb_en_0.pdf

incentives and risk for market participants, international comparisons with other electricity markets and interactions with other energy market developments. The current price used in imbalance pricing of £6,000/MWh was set as it represents the upper end of industrial and commercial VoLLs and hence provides incentives for most industrial and commercial consumers to enter into interruptible contracts and provide DSR services. This increases overall capacity availability and should provide sufficient financial incentives for existing market participants to increase generation or reduce demand when the system is tight; whilst limiting the overall financial risk to them if they are still out of balance.

However, Ofgem acknowledge there is a case to continue to keep the value of VoLL used in imbalance pricing under review. To this end, Ofgem have provided the code administrator with powers to review the figure for VoLL should they believe there is a case, and Ofgem have stated that it will be kept under review, but any revision would need to be considered with caution. Similarly, the UK Government has committed as part of the Capacity Market five-year review to review the value of VoLL for GB of £17000/MWh used in the calculation of the GB electricity reliability standard. Although we believe that the reliability standard itself lies within the right range, we recognise that some of the components that make up the standard may require an update (e.g. net CONE and VoLL).

Balancing markets: Procurement of ancillary services in Great Britain

NG:ESO procures a number of services to ensure the security and quality of electricity supply in GB. The full list of ancillary services procured by the NG:ESO is set out in Table 1.

Balancing service providers are allowed to submit or update their bids until the balancing energy gate closure time. IT systems prevent bids or offer prices in excess of £99,999/MWh in the Balancing Mechanism.

NG:ESO is currently updating contracts for two of its balancing services, Fast Reserve and STOR, to ensure that utilisation prices are not pre-agreed as part of the tenders, in line with the requirement of the European Balancing Guideline (EBGL).

Table 1: Ancillary services procured by NG:ESO

Balancing Services		Proposed Final Product Type		Timescales for procurement	Payments
Contract Type	Service	Group	Type		
Mandatory frequency response	Primary response	FCR*	Specific	Within day auction	Availability is pay as bid, utilisation is pay as cleared
	High response	FCR	Specific	Within day auction	
	Secondary response	FRR**	Specific	Within day auction	

Commercial Frequency Response Service	Primary response	FCR	Specific	Ad hoc bilateral / tender	
	High response	FCR	Specific	Ad hoc bilateral / tender	
	Secondary response	FRR	Specific	Ad hoc bilateral / tender	
[Firm frequency response](#) (FFR)	Primary response	FCR	Specific	Monthly & Quarterly Tenders & Weekly Auctions	
	High response	FCR	Specific	Monthly & Quarterly Tenders & Weekly Auctions	
	Secondary response	FRR	Specific	Monthly & Quarterly Tenders & Weekly Auctions	
Enhanced frequency response	Enhanced frequency response	FCR	Specific	No longer procured	Availability is pay as bid
Commercial Frequency Management Service	N/A	FCR	Specific	Ad hoc bilateral / tender	Availability is pay as bid
[Short-term operating reserve](#) (STOR)	Delivery < 15 minutes	FRR	Specific	Firm tender suspended pending review of move to day ahead; optional market available within day	Availability and Utillisation is both 'pay as bid' for Firm; Utilisation only for Optional
	Delivery > 15 minutes	RR***	Specific	Firm tender suspended pending	Availability and Utillisation is both 'pay as bid' for Firm;

				review of move to day ahead; optional market available within day	Utilisation only for Optional
Demand Turn Up (DTU)	Delivery < 15 minutes	FRR	Specific	No longer procured	Availability is pay as bid
	Delivery > 15 minutes	RR	Specific	No longer procured	Availability is pay as bid
Fast Reserve		FRR	Specific	Monthly tender suspended pending review of move to day ahead; optional market available within day	Availability and Utillisation
Balancing Mechanism (BM) Bids and Offers	Delivery < 15 minutes	FRR	Specific	Within day auction	Availability is pay as bid
	Delivery > 15 minutes	RR	Specific	Within day auction	Availability is pay as bid
Fast Start		FRR	Specific	No longer procured	Availability and Utillisation are both 'pay as bid'
Optional Downward Flexibility Management	Delivery >15 minutes	RR	Specific	Weekly availability nomination	Availability is pay as bid
Mandatory Reactive		System	n/a	Within day	n/a as service is neither balancing energy nor balancing capacity
Enhanced Reactive		System	n/a	Twice a year tender	n/a as service is neither balancing energy nor balancing capacity

Constraint Management (Voltage/Thermal/Stability)	System	n/a	Ad hoc	n/a as service is neither balancing energy nor balancing capacity
Black Start	System	n/a	Ad hoc	n/a as service is neither balancing energy nor balancing capacity
Intertrips (Commercial/Operational)	System	n/a	Ad hoc	n/a as service is neither balancing energy nor balancing capacity
Trip to House Load	System	n/a	Ad hoc	n/a as service is neither balancing energy nor balancing capacity
BM Start up	System	n/a	Ad hoc	n/a as service is neither balancing energy nor balancing capacity
Hot Standby	System	n/a	Ad hoc	n/a as service is neither balancing energy nor balancing capacity

* FCR: Frequency containment reserve

** FRR: Frequency Restoration Reserve

*** RR: Replacement Reserves

Demand Side Response

Demand side response (DSR) providers are eligible to participate in the balancing / ancillary services markets, the CM, and they are active in other markets.[27] DSR is treated the same as other technologies commercially, however there are technical differences in some services around dispatch and monitoring as DSR assets typically do not have the same communications infrastructure - e.g. no SCADA (Supervisory Control and Data Acquisition) links to the control room. DSR can participate in these markets directly and via aggregators.

DSR is also eligible to participate in the wholesale electricity markets, including day-ahead and intraday. DSR can be represented as both individual participants or via aggregators in wholesale markets as long as they hold a supply licence under the Electricity Act 1989.

[27] The 2018 Power Responsive Annual Report provides metrics and a breakdown by service: http://powerresponsive.com/updates/

Retail market / regulated prices

The GB retail market does not have a system of regulated electricity prices for final customers. Prices for final customers in GB are set by the market, which has a wide price range, and customers are free to choose their supplier and tariff. However, there are currently temporary caps on: the rates paid by household prepayment meter tariffs ('the Prepayment Meter Cap'), due to particular restrictions on consumer engagement and competition in that market; and the rate suppliers may charge consumers on standard variable and default tariffs ('the Default Tariff Cap').

The levels of the caps are set and regularly reviewed by the independent energy regulator, Ofgem, and maintain incentives for consumers to switch and for suppliers to compete, while enabling suppliers to recover the efficient costs of supplying their customers. The caps allow for rates to be set by suppliers, so long as they do not breach the maximums allowed in the region and for the type of meter and payment method. Consumers on tariffs covered by the caps are free to switch away to other competitive offers at any time.

The Prepayment Meter Cap expires on 31 December 2020. The GB independent energy regulator is currently consulting on whether customers covered by this cap need further protection after it expires.

The Default Tariff Cap is also a temporary, time-limited measure. It was introduced to protect customers from unjustifiably high prices in a segment of the market where consumer engagement is weak (sometimes referred to as 'loyalty penalty pricing') while steps are taken to address the underlying issues which contribute to this problem. Each year, Ofgem and the Secretary of State will review whether the conditions for effective competition for domestic supply contracts are in place. Under the legislation, if the Secretary of State determines they are in place, the cap will end; if not, the cap will be extended another year, until the end of 2023 at the latest.

The UK Government and Ofgem are in the process of introducing policies to remove barriers to engagement and increase competition, including the roll-out of Smart Meters and the Faster Switching and Midata programmes. These form part of a range of policies being implemented to address the underlying issues within the market which originally necessitated the introduction of the caps currently in place. As mentioned above, these caps are temporary measures, and the UK Government is committed to improve market conditions so that such measures are no longer required. The Government is also considering further interventions as longer-term solutions to directly tackle the causes of 'loyalty penalty pricing' through the Future Retail Market Review. Interventions of the kind suggested by the Commission[26] will feature in this policy development process.

Interconnectors

When the GB national electricity transmission grid was built in the 1950s there were no connections to adjacent national networks. Today, the GB electricity system is connected with north-west Europe via 4GW interconnector capacity - 2GW with France, 1GW with Belgium and 1GW with the Netherlands. 1GW of interconnection also links GB and the Single Electricity Market (SEM) on the island of Ireland. In 2018, net imports increased by 29% compared to 2017, with imports increasing to 21.3TWh and exports decreasing to 2.2TWh. Net imports accounted for approximately 6% of electricity supplied in 2018.

Table 2: Existing interconnectors

Project	Cost (£m)	Connection Capacity MW	Connects GB to	Delivery date	Regulatory route	Owners
IFA	1500	2000	France	1986	Merchant	NGIH
Moyle	150	500	Northern Ireland	2002	100% regulated in Northern Ireland – fixed regulated returns	Mutual Energy
BritNed	530	1000	Netherlands	2011	Merchant	NGIH / Tennet
EWIC	500	500	Ireland	2012	100% regulated in Ireland – fixed regulated returns	EirGrid
NemoLink	500	1000	Belgium	2019	Cap & Floor	NGIH / Elia

The first interconnector to France was installed in 1961, with a capacity of 160MW, and it was replaced in 1986 by the 2,000MW current link (the IFA). These interconnectors were developed jointly by the nationalised utilities Central Electricity Generating Board and Electricité de France, but are now jointly owned by National Grid Interconnectors Limited (a distinct entity from National Grid Electricity Transmission) and RTE (Réseau de Transport d'Electricité).

A link between GB and Northern Ireland (Moyle) was built in 2001 with a 500MW capacity. Due to the risks to system stability of connecting two differently-sized markets, the available capacity is restricted to less than 500MW. This was not technically an interconnector as it was within the UK, but with the creation of the Single Electricity Market on the island of Ireland it is now treated as such. A 500MW interconnector between the Republic of Ireland and GB was completed in 2012 by the Transmission System Operator, EirGrid, and is referred to as the East-West Interconnector (EWIC).

A 1,000MW interconnector between GB and the Netherlands (BritNed) was developed as a merchant project jointly by National Grid Interconnectors Limited and the Dutch System Operator (Tenne-T), and started operating in April 2011.

The business model for interconnectors has generally been of state-owned infrastructure, but this developed into a regulated asset base which can be owned by private companies. BritNed was developed on a merchant basis. Under this approach, private developers identify market opportunities, construct and operate the assets, and take the full upside and downside risk on revenues. In contrast, NEMO Link is the pilot project for Ofgem’s Cap and Floor regime. This regulated approach guarantees a minimum floor revenue if the interconnector meets a number of conditions. This guaranteed minimum revenue has proved popular with developers by reducing debt finance risk. Conversely, if revenues exceed the cap, any excess is recycled to consumers. ‘Market opportunities’ primarily means price differences between the two connected markets, such that parties wish to pay the interconnector owner for capacity to trade electricity (congestion rents). This must, of course, be weighed against the costs of building and operating the interconnector.

GB being an island, the costs of delivering interconnection are higher and involve greater risks than on mainland Europe as interconnection necessitates longer, subsea cables rather than onshore network development. The developer-led, merchant model harnesses market forces in identifying the most efficient interconnector opportunities and, as a result, the risk of expensive sub-sea assets being developed that are under-utilised (stranded assets) is low. However, this also means that GB currently has a lower level of interconnected capacity than the UK Government would like to see. Further interconnection is likely to be beneficial for GB and GB consumers, as well as EU Member States. Our efforts to increase the levels of interconnection to GB are set out in the Part 4.

In GB, electricity interconnectors are operated as independent commercial assets and each interconnector owner has a commercial incentive to maximise availability at all times. Given that GB interconnectors function on HVDC (High Voltage Direct Current) rather than AC (Alternating Current) connection, unscheduled flows limiting trade is not an issue in relation to underutilisation of interconnection capacity.

Existing market distortions and failures

Like many of its European counterparts, the UK faces an unprecedented challenge. It needs to ensure security of supply while decarbonising its electricity supply against a background of the closure of existing generation. The GB CM was introduced in 2014 following the identification of resource adequacy concerns, and associated market failures in the GB electricity market contributing to these concerns.

The need to act to introduce and continue operating a GB CM scheme was based on the following rationale:

- GB, as with the rest of the EU, relies on secure energy supplies to function effectively and to attract private investments;
- Despite the historically strong security of supply in the GB electricity market, there is clear evidence that the market faces new challenges which pose significant risks to security of supply: market failures, rapid closure of a significant amount of existing capacity, and an increasing proportion of intermittent capacity deployed to meet decarbonisation targets; and
- When the GB CM was introduced, about 10GW of electricity generation capacity was scheduled to close over the 10 years following 2014, including around 8 GW of nuclear capacity, and 1 GW of coal capacity as a result of the Large Combustion Plant Directive (LCPD). In reality, since 2014, 3.5GW of coal capacity has announced closure by 2020, and 4.27GW of nuclear capacity is scheduled to close by 2025. We expect the remaining 5.3GW of coal capacity to also close between now and October 2025, as this is the date by which the UK Government has committed to phase out all unabated coal generation. The exact timing of future plant closures, including nuclear capacity, depends on commercial decisions made by operators.

As explained in the UK's State aid notification in 2014, whilst in theory the market should provide incentives for sufficient investment in reliable capacity, the GB electricity market - like many others - faces market failures, exacerbated by new pressures such as the growth of intermittent renewable generation, which means that there is a significant risk this will not be the case. The market failures identified were:

- Reliability is a public good;
- The missing money problem; and
- Barriers to entry.

These market failures exist to some extent in all electricity markets. However, they are very significantly exacerbated by the GB electricity market's specific circumstances in the coming years, when a significant amount of existing capacity is due to close and the UK will steadily move closer to its ambitious decarbonisation targets.

Reliability is a public good

Customers cannot choose their desired level of reliability, since the NG:ESO cannot selectively disconnect them, and consumers do not respond to real-time changes in the wholesale price. It can therefore be expected that capacity providers will not provide the socially optimal level of reliability in the absence of intervention. This may also lead to high costs to society as a result of having an unreliable electricity supply. These would be external costs if they are not charged to generators.

The 'missing money' problem

In theory the inability of consumers to select their desired level of reliability could be addressed in an energy-only market by allowing prices to rise to a level reflecting the average value of lost load (i.e. the price at which consumers would no longer be willing to pay for energy) and allowing generators to receive scarcity rents.

However, in practice an energy-only market may fail to send the correct market signals to ensure optimal security of supply and to enable investors to obtain project finance for building new capacity. This means that energy market revenues alone may fail to bring forward sufficient investments in capacity due to 'missing money'. The reasons why this may happen are twofold:

- An inability of prices to reflect scarcity - wholesale energy prices do not rise high enough to reflect the value of additional capacity at times of scarcity. This is due to the fact that charges to generators who are out of balance in the balancing mechanism (cash-out) do not reflect the full cost of the balancing actions taken by the System Operator (such as voltage reduction); and
- A lack of certainty that prices will rise, even if they can - At times when the wholesale energy market prices should peak to high levels, investors are concerned that the Government/market regulator will act on a perceived abuse of market power, for example through the introduction of a price cap. They are also concerned that prices

simply will not rise - for example, if wind capacity performs better than expected, reducing the opportunities for more expensive dispatchable capacity to run.

'Missing money' is not a theoretical problem. Historically, GB cash-out prices have risen to a maximum of £1,528/MWh.

Barriers to entry

The regulatory risk, lack of forward liquidity, and the challenges of 'missing money' mean that there are real barriers for new market entrants to overcome if they are to invest – particularly if they need to secure project or debt finance. This could act to restrict the number of participants in the wholesale electricity market.

Decarbonisation

To meet its national decarbonisation ambitions, the UK Government aims to rapidly decarbonise electricity supply. This means moving to a system with a much higher proportion of intermittent wind generating capacity, and less flexible nuclear plants. The increase in the proportion of low carbon capacity with low running costs exacerbates the 'missing money' problem by undermining the case for investment in reliable, dispatchable capacity. Flexible plants such as gas have higher operating costs relative to most low carbon plants. As such, these plants will run less often and be increasingly reliant on high prices in short periods to recover their costs of investment. However, it is very difficult to predict the duration of these periods and so whether they will justify the level of investment in new plant required. This will act as a disincentive to investment, particularly from merchant investors, and there is a significant risk that it will result in insufficient reliable capacity being on the system to meet demand.

Investors in flexible capacity should theoretically be able to receive sufficient revenues in the energy market to justify investment – but this is true only if prices are able to rise to a sufficient level and only if the market is willing to invest on the basis of such uncertain scarcity rents and has confidence that it will be allowed to operate in an unconstrained way. As such, the level of flexible capacity required may not come forward, potentially putting energy security at risk at times of high demand and low renewable output.

Measures to address the identified market failures

The UK Government has pursued - and continues to pursue - a range of actions to address the market failures described in Part 3. These include reducing overall electricity requirements, increasing energy efficiency, enabling a more price responsive demand side (e.g. through the roll out of smart meters), and reforming imbalance settlement arrangements to improve price signals ('cash out reform'). The Government also supports greater levels of interconnection, with a further 4.8GW of capacity already in construction.

Removing price caps

Liberalisation of the electricity markets started in the late 1980s. There are now no price caps or regulated prices in relation to wholesale electricity in the GB electricity market. Temporary and targeted price caps are in place for specified retail products, and are set based on observed wholesale prices.[28] Details of these measures in relation to final customers on prepayment meters and those on standard variable or default tariffs are set out in the section on 'Regulated Pricing' below.

Imbalance settlement

Part of the missing money market failure is the inability of imbalance prices to reflect scarcity. Generators out-of-balance in the balancing mechanism face costs (cash out) that do not reflect the full cost of the balancing actions taken by the System Operator (SO), such as voltage reduction. Ofgem launched the Electricity Balancing Significant Code Review (EBSCR) in 2012 to address several long-standing concerns about factors that have dampened cash-out prices. Ofgem published their final policy decision in May 2014.[29] The reforms to cash out were to:

- Make cash-out prices 'marginal' by calculating them using the most expensive action the SO takes to balance the system. This was introduced in steps: the first step was that prices would be calculated using an average of the top 50MWh of SO actions (rather than 500MWh) from November 2015; and the second step was the calculation of prices using the top 1MWh from November 2018;

- Include a cost for disconnections and voltage reduction into the cash-out price calculations based on the Value of Lost Load (VoLL) to consumers. Again this was introduced in steps with VoLL set at £3,000/MWh from November 2015, and at £6,000/MWh from November 2018;

- Improve the way reserve costs are priced by reflecting the value reserve provides to consumers at times of system stress; and

- Move to a single cash-out price for each settlement period to simplify the arrangements and reduce imbalance costs, in particular for smaller parties.

[28] These caps are therefore out of scope of Article 10 of Regulation (EU) 2019/943
[29] https://www.ofgem.gov.uk/publications-and-updates/electricity-balancing-scr-launch-statement

Ofgem has published a review of the first phase of the EBSCR.[30] The data used in Ofgem's review covers two years either side of the reform - the pre-modification period was the two years before the implementation of the code modification in November 2015, which was to be compared with the two years after the implementation of the code modification. Since the implementation of the first phase we have seen the average Imbalance Price (cash out price) fall. The majority of Imbalance Prices in the post-modification period now lie within the range of £20-30/MWh, rather than £30-£40/MWh as observed in the pre-modification period. The Imbalance Price has, however, become more volatile. The maximum price in the two years before the reform was implemented was £429.10/MWh whereas in the two years after the reform it was £1,528.72/MWh.

The decision by Ofgem on the code modification which implemented the Reserve Scarcity Pricing Function (RSP), improving how reserve costs are priced, considered that the methodologies developed are robust and would lead to price increases at the right time – when margins are tightest.[31] The Commission's Opinion[26] invites the UK to consider whether the price adder which the referred function creates in times of scarcity should apply not only to balance responsible parties but also to balance service providers which provide balancing energy to the TSO. Ofgem's decision noted that the RSP methodologies have room to be strengthened further, and that the work carried out by the workgroup provides a good platform for the industry to take an active role in improving and refining the RSP methodology over time.[31]

The Government believes that the CM and cash-out reform have distinct but complementary roles in seeking to ensure security of electricity supply. It is better to pursue the CM and support reform of the cash-out arrangements, rather than simply to rely on the cash-out reform for the following reasons:

- While cash-out reform should strengthen energy market investment incentives in the long term, it is expected to have a more limited impact on overall levels of investment in the short and medium term. This is because generators sell almost all their energy in forward markets. However, over time the cash-out reform will lead prices in forward markets to rise as generators exploit arbitrage opportunities between forward markets and the price in the balancing mechanism;

- Cash-out reform cannot address the increased riskiness of investment in thermal capacity as the power sector decarbonises: thermal capacity will increasingly run as backup and will have to recover its fixed costs through earning high prices on the few occasions where there is scarcity and prices rise;

- In practice, the potential for scarcity rents (the difference between the market price and the highest short run marginal cost of the plant at the margin) is only likely to induce investments if a liquid market develops for 'reliability options' trading around a real-time price – whereby suppliers pay generators a fixed price in exchange for an option to buy energy at a strike price. This is unlikely to emerge under Ofgem's proposed reform of cash-out arrangements;

- It is unclear whether investors will have confidence that any new arrangements would be maintained. This is because when prices are allowed to peak to high levels, it becomes increasingly difficult for the regulator to assess whether very high prices are efficient market operation or profiteering. This means that generators may be averse to

[30] https://www.ofgem.gov.uk/system/files/docs/2018/08/analysis_of_the_first_phase_of_the_electricity_balancing_significant_code_review_as_final_version_publication.pdf
[31] https://www.elexon.co.uk/wp-content/uploads/2014/05/P305D-v2.0.pdf

offering energy at a high price (for fear of investigation for abuse of market), or that they may expect some sort of intervention in the future.

Although cash out reform could lead to higher prices during times of scarcity, the inherently high level of uncertainty regarding scarcity events makes relying on high scarcity rents alone a risky strategy for investors in large new build projects. The CM provides a stable, regular payment for up to 15 years for new build projects which reduces risks to investors and encourages investment in new and existing capacity. In the event that cash-out reforms work well to address market failures, sharper cash-out prices have the potential to reduce the cost of procuring capacity through the CM.

Interconnection

The UK Government recognises the potential for further interconnection to contribute to energy security, affordability and decarbonisation objectives and supports projects which enable these outcomes.

National Grid's Network Options Assessment (NOA) 2018/2019 recommended an investment of £59.8m in 2019/20 across 25 asset-based projects to maintain the option to deliver projects costing almost £5.4bn, allowing us to manage the future capability of the GB transmission network and support the future development of the networks in an efficient, economical and coordinated way.

We are continuing to develop more electricity interconnection to open-up trade with neighbouring markets, supported by Ofgem's Cap and Floor regime,[32] which is the regulated route for interconnector investment in GB. This regime has reduced risks and unlocked substantial investment in interconnection, reflected in the number of new interconnectors under construction from GB and those that have received regulatory approval for projects.

The UK's Clean Growth Strategy[33] has stated that there is potential for at least 17.9GW of interconnection to the GB market. This figure is based on projects that have all either entered into construction or undergone regulatory assessment, and which are all targeting delivery before 2030. In addition to the 5GW that is operational, 4.8GW of capacity is already in construction, and a further 8.1GW is progressing through regulatory approvals (of which 6.1GW has been granted an initial regulatory approval under the Cap and Floor regime). This strong pipeline of projects will significantly increase our level of interconnection by 2030.

[32] https://www.ofgem.gov.uk/system/files/docs/2016/05/cap_and_floor_brochure.pdf
[33] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/700496/clean-growth-strategy-correction-april-2018.pdf

Table 3: Pipeline of interconnectors

Project	Cost (£m)	Connection capacity MW	Connects GB to	FID reached	Delivery date	Regulatory route	Developer
NSL	1700	1400	Norway	Mar 2015	Q4 2021	C&F	NGV / Statnett
ElecLink	490	1000	France	Nov 2016	(2020)	Merchant	GETLink (Eurotunnel)
IFA2	700	1000	France	Mar 2017	Q4 2020	C&F	NGV / RTE
Viking-Link	1700	1400	Denmark	Q3 2018	Q4 2023	C&F	NGV / EnergiNet
FABLink	550	1400	France	TBD	2023	C&F	FAB Link / RTE
Green-Link	330	500	Ireland	Q3 2020	2023	C&F	Element Power
North-Connect	1400	1400	Norway	Q1 2020	2023 /2024	C&F	North-Connect
Aquind	1000	2000	France	(2019)*	2022*	Merchant	Aquind
GridLink	600	1400	France	(2019)*	2024	C&F	GridLink
Neu-Connect	1200	1400	Germany	Q3 2020	2023	C&F	Neu-Connect

* Estimated dates (based on requirements placed on developers by Ofgem). Project milestones may occur later.

Energy storage and DSR

The UK Government is working closely with the energy regulator (Ofgem) and industry to support the transition to a smarter, more flexible energy system. Our aim is to establish a best-in-class regulatory framework to harness the full potential of smart and flexible energy solutions such as storage, DSR and interconnection. A smart and flexible system can help streamline the electricity system and help us meet our decarbonisation targets more efficiently by reducing system operation costs (e.g. balancing) and by making more efficient use of existing network infrastructure and generation assets.

Following preceding work and a call for evidence, in July 2017, the UK Government and Ofgem jointly published a Smart Systems & Flexibility Plan (SSFP).[34] This plan outlines the underlying principles of our approach to enable the transition to a smart and flexible system, followed by 29 actions for the UK Government, Ofgem and/or industry to lead on to realise this.

The actions are split across three core themes:

- Removing barriers to smart technologies, such as electricity storage;
- Enabling the use of smart solutions, including DSR, in homes and businesses; and
- Ensuring markets provide the right incentives for flexibility and smart solutions.

In October 2018, the UK Government and Ofgem published a Progress Update[35] to the Plan, which identified 9 new actions beyond those set out in the original Plan. We have implemented over half of the actions in the plan and progress update, and intend to implement the remainder by 2022.

Our approach centres on removing policy and regulatory barriers to smart energy solutions and enabling them to enter the market and compete fairly alongside other new or established energy technologies. The below provides further details on each of the three core themes:

Removing barriers to electricity storage

The SSFP focuses on creating a best-in-class regulatory framework for storage by removing regulatory barriers, and reforming markets so that storage is rewarded fairly for the value that it provides to the system. The actions set out for electricity storage in the SSFP include:

- Government will define electricity storage as a distinct subset of generation in primary legislation, when parliamentary time allows;
- Government has committed to remove electricity storage, except pumped hydro storage, from the national planning regime in England and Wales[36], this will make it simpler for large-scale storage facilities to seek planning permission. The statutory instruments needed to achieve this began their passage through Parliament on 14 July, when the first order (under the Planning Act 2008) was laid before Parliament;
- Ofgem have published modifications to the generation licence for storage.[37] This will enable storage licence holders to avoid overpayment of policy levies;
- Industry has raised a series of modifications to reform network charges for storage, so that storage does not overpay for use of the system. These are progressing through industry governance, and the majority have already been approved by Ofgem;[38]

[34] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/633442/upgrading-our-energy-system-july-2017.pdf
[35] Upgrading Our Energy System: Progress Update, October 2018, https://www.ofgem.gov.uk/system/files/docs/2018/10/smart_systems_and_flexibility_plan_progress_update.pdf
[36] https://www.gov.uk/government/consultations/the-planning-system-for-electricity-storage-follow-up-consultation
[37] https://www.ofgem.gov.uk/publications-and-updates/clarifying-regulatory-framework-electricity-storage-statutory-consultation-proposed-modifications-electricity-generation-licence
[38] The details of the modifications can be accessed at the following links: CMP280, CMP281, CMP319, DCP341, DCP342 and P383

- Government has launched a health and safety governance group[39] to ensure an appropriate, robust and future-proofed health and safety framework is sustained as storage deployment increases; and
- Industry are taking forward actions to ensure the network connections process is appropriate and does not present any undue burdens to storage.

Enabling the use of DSR in homes and businesses

Enabling the use of smart solutions in homes and businesses, principally via enabling consumers to participate in DSR, is a core theme in the SSFP. Key enablers of DSR include the roll-out of smart meters and the move towards market-wide half-hourly settlement, which together provide a framework for the increased provision of smart tariffs. Smart tariffs in turn unlock the value of smart appliances, these are connected devices that respond to signals - such as price - by modulating energy consumption, and so are key to DSR.

Smart meters are replacing traditional gas and electricity meters across Great Britain[40] as part of an important national upgrade that will build a smart grid, digitise our energy system and drive innovation. Energy suppliers are responsible for installing smart meters and there are 21.5 million smart and advanced meters in homes and small businesses across GB.[41] The programme is expected to deliver total net benefits of around £6 billion, the majority of which come from consumer energy savings and industry operational cost savings.[42] Following a public consultation, in June 2020 the UK Government confirmed it will introduce a new approach for the next phase of the smart meter rollout which will set clear, defined outcomes for all energy suppliers to deliver a market-wide rollout as soon as practicable.[43]

Smart meters are an enabler of time-of-use (ToU) tariffs which have lower energy prices at off-peak times. The first static ToU tariff in the UK was introduced by Green Energy in early 2017, offering its smart meter customers a much cheaper rate of electricity during weekday nights. However, this does not reflect actual wholesale costs which would allow consumers to respond in real time. There is currently only one dynamic ToU tariff, launched by Octopus Energy in February 2018 which provides consumers with half-hourly price updates that reflect actual wholesale energy costs.

The UK Government intends to set regulatory requirements for certain smart appliances that are suitable for flexible consumer use, e.g. fridges and washing machines, to support their uptake and to guard against potential risks, including relating to data privacy and cyber security. In tandem, we are developing appropriate technical standards for smart appliances, including electric vehicle (EV) charge-points, with the British Standards Institution.[44]

Consumer protection is a key consideration as we transition to a smart energy system. For example, we have supported the development of industry-led standards for energy aggregators, and we continue work to address potential future cyber security risks.

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[39] More information on the health and safety governance group can be found in the Smart Systems and Flexibility Plan: Progress Update

[40] i.e. England, Wales and Scotland. Responsibility for energy markets in Northern Ireland lies with the Northern Ireland Executive's Department for the Economy

[41] https://www.gov.uk/government/statistics/smart-meters-in-great-britain-quarterly-update-march-2020

[42] https://www.gov.uk/government/publications/smart-meter-roll-out-cost-benefit-analysis-2019

[43] https://www.gov.uk/government/consultations/smart-meter-policy-framework-post-2020

[44] https://www.bsigroup.com/en-GB/about-bsi/uk-national-standards-body/about-standards/Innovation/energy-smart-appliances-programme/

The roll out of smart meters and uptake of ToU tariffs could increase the responsiveness of consumer demand, allowing consumers to manage their consumption in response to scarcity signals from the market. The market failure of reliability as a public good would be less relevant as consumers would be able to respond to real-time changes in the wholesale price.

Balancing services

The SSFP set out key actions for NG:ESO to open up access to existing balancing services markets to a wider range of flexible technologies, including energy storage and DSR. Since the publication of the plan, progress has been made in reforming balancing services.

NG:ESO published a number of roadmaps including wider access to the Balancing Mechanism (BM), Restoration, Reactive Power and Frequency Response & Reserve.[45] The documents set out future system needs, and timelines for the rationalisation of ESO products into a smaller number of more competitive, technology neutral products.

Since 2018, we have allowed aggregators to access the BM. The implementation of wider code modifications through Project TERRE (Trans European Replacement Reserves Exchange) have opened up the BM to a wider range of flexibility providers. The wider access to the BM went live in December 2019 and enables distributed generation and independent flexibility aggregators to participate directly in the BM. This is an industry first, facilitating more DSR and increasing competition in the BM

In June 2019, NG:ESO started trialling new ways of procuring frequency response through weekly auctions. The trial is expected to allow DSR and intermittent generation to participate more effectively in ancillary services.

These reforms will ensure that our electricity system can cost-effectively manage increasingly decentralised generation whilst supporting the technologies that are key to meet the UK's 2050 net zero target.[46]

Enabling self-generation

Since 2010, small-scale generators have been supported mainly through the Feed-in Tariffs (FIT) scheme. While the FIT scheme closed to new applicants on 31 March 2019, self-generators on the scheme receive 20 or 25 years of support each, meaning the scheme will continue to support self-generation until 2039.

To follow on from the FIT scheme, on 10 June 2019, the UK Government introduced the Smart Export Guarantee (SEG) to ensure that small-scale generators have the right to be paid for the self-generated renewable electricity that they export to the grid. From 1 January 2020, licensed suppliers with 150,000 or more domestic customers are required to provide at least one tariff offer to any eligible small-scale generator exporting electricity to the grid.[47]

[45] https://www.nationalgrideso.com/publications/future-balancing-services
[46] https://www.gov.uk/government/news/uk-becomes-first-major-economy-to-pass-net-zero-emissions-law
[47] See https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/807393/smart-export-guarantee-government-response.pdf; and https://www.gov.uk/government/consultations/the-future-for-small-scale-low-carbon-generation-part-b

Promoting energy efficiency

The UK Government supports cost-effective improvements to energy efficiency in line with our ambitious domestic decarbonisation objectives. As shown in our 2019 progress report[48] under the Energy Efficiency Directive, the UK Government has a strong track record of delivering on energy efficiency, including through commitments to fund energy efficiency improvements in the public sector, industry, business and homes.

Some of our recent policies to promote energy efficiency include a Call for Evidence on Facilitating Energy Efficiency in the Electricity System[49], a commitment to introducing a Future Homes Standard which will see new build homes future-proofed with low carbon heating and the highest standards of energy efficiency by 2025. A number of policies and schemes are already in place to support businesses to cut their energy use – such as the Climate Change Agreements Scheme, the Energy Savings Opportunity Scheme, and the introduction in April 2019 of Streamlined Energy and Carbon Reporting by all UK large or quoted businesses.

In 2018, the UK Government announced that it will establish an Industrial Energy Transformation Fund, backed up by £315m of investment, to support businesses with high energy use to transition to a low carbon future and to cut their bills through increased energy efficiency. As set out in the consultation of the scheme, the UK Government intends to launch the first phase of the Fund with guidance for applications in spring 2020 and to open for applications in summer 2020. The second phase will commence in 2021.[50]

Regulated pricing

The Prepayment Meter Price Cap came into force on 1 April 2017. The cap is temporary and applies to all prepayment meter customers (excluding customers with a fully interoperable smart meter). This cap expires on 31 December 2020. The GB independent energy regulator is currently consulting on whether customers covered by this cap need further protection after it expires.

This provision is consistent with the derogation in paragraph 3 of Article 5 of Directive (EU) 2019/944 of the European Parliament and of the Council of 5th June 2019 on common rules for the internal market for electricity ('the recast Electricity Directive').

Following an Act of Parliament, on 1 January 2019 Ofgem introduced a price cap on standard variable and default tariffs ('the Default Tariff Cap'). This will be in place until the end of 2020, but may be extended by a year at a time until the end of 2023 at the latest, if the conditions for effective competition are not yet in place. The intention is to protect these particular customers from excessive prices until the conditions for effective competition are in place.

This provision is consistent with the derogation in paragraph 6 of the recast Electricity Directive.

[48] https://ec.europa.eu/energy/sites/ener/files/documents/uk_annual_report_2018_en.pdf
[49] https://www.gov.uk/government/consultations/facilitating-energy-efficiency-in-the-electricity-system
[50] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/816012/Panel_of_Technical_Experts_report_2019.pdf

The GB Capacity Market

The UK Government considers that the reforms identified in this section will not be enough to ensure security of supply in the short to medium term, which is why a GB-wide capacity mechanism, in the form of the GB CM, was introduced and continues to operate.

The UK Government's view is that there is a strong need to maintain the CM, given that many of the underlying issues that led to its introduction continue. In particular, the significant coal and nuclear plant closures expected in the 2020s, the persistence of the 'missing money' problem, and the continued rapid evolution and decarbonisation of the GB electricity system.

As explained in Part 2, GB continues to experience resource adequacy concerns, with recent analysis from NG:ESO suggesting that LOLE would be above three hours between 2019/20 and 2023/24 without the CM.[51] In contrast, with a CM in place, NG:ESO forecast LOLE to range between zero and one hour in the same period. The reliability standard in GB is three hours LOLE, therefore without the CM it appears unlikely that we would consistently meet the reliability standard over the next 5 years.

In July 2019, the UK Government published a five-year review of the capacity market - as required by the domestic legislation that implements the CM - following a Call for Evidence.[52,53] In the review we noted that a clearing price close to zero in the CM auctions for a sustained period could be interpreted as an indication that the 'missing money' problem may have been resolved. Clearing prices over the lifetime of the CM have been variable, but in excess of £0/kW. Whilst clearing prices have been low in recent auctions, there are reasons to believe they are likely increase in future e.g. as a result of expected generation plant closures. The responses to the call for evidence broadly supported the continued need for the CM.

In light of the assessment by NG:ESO, and the responses to our CFE, we are committed to the continuation of the CM for the foreseeable future. We will revisit the need for a CM as part of the ten-year review of the CM, which we are required to carry out under the implementing legislation,[54] and as the current State aid approval for the CM expires in December 2024. Moreover, NG:ESO assesses resource adequacy each year in GB as part of the ECR process which determines the auction targets and informs the UK Government's decision on whether to hold auctions.

The UK Government is committed to continually improving the CM design to ensure it better meets its objectives. Following the five-year review, we identified three key themes under which we intend to make further improvements to the CM. These themes are:

- Futureproofing and maintain technology neutrality;

[51] NG:ESO have undertaken a detailed review of the economics of coal, gas and small peaking plant utilising the best publicly available cost data with their own assessment of the various market revenue streams e.g. wholesale, balancing, ancillary services and the CM. This enabled them to identify the individual plants at greatest risk of closing when CM revenues are no longer available and the impact of their closure on loss of load expectation (LOLE). They also carried out sensitivity analysis on their assessment, by analysing what the impact would be on the margin and LOLE metrics if there were 1GW less or more closures than expected.
[52] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/819760/cm-five-year-review-report.pdf
[53] https://www.gov.uk/government/consultations/capacity-market-and-emissions-performance-standard-review-call-for-evidence
[54] The implementing legislation requires government to carry out a five-yearly review of the GB CM scheme and publish a report summarising the review.

- Simplification of the CM mechanism; and
- Procuring the right amount of capacity.

Additionally, the Commission's State aid decision, in 2019, confirming that the GB CM scheme complies with EU State aid rules, identifies that the UK Government has committed to implementing a number of improvements to the scheme for the future.[55] This included a commitment to respect the provisions of the recast Electricity Regulation (Regulation (EU) 2019/943), in particular the requirement to phase out CM support for generation capacity that emit more than 550g of CO2 of fossil fuel origin per kWh of electricity, starting with new build capacity. In July 2019, we implemented the limit in relation to new build capacity in the CM[56] and launched a consultation which considers proposals on how to implement the carbon emissions limit for existing and refurbished plant.[57]

We consulted on arrangements for implementing six of the seven commitments recorded in the Commission's 2019 decision, and have now implemented these changes.[58]

[55] https://ec.europa.eu/commission/presscorner/detail/en/IP_19_6152
[56] These changes were implemented via the Capacity Market Amendment (No. 5) Rules 2019.
[57] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/829746/proposals-capacity-market-emissions-limits-consultation.pdf
[58] https://www.gov.uk/government/consultations/capacity-market-proposals-for-future-improvements

Annex A - Summary and timeline of measures

The table below provides a summary of the measures the UK Government has pursued - and continues to pursue - to eliminate the identified market failures which led to the introduction of the GB CM; and measures to ensure the continued improvement of the CM.

Table 4: Summary and timeline of measures

Measure	Description	Date for completion	Relevant links
Removing price caps	Liberalisation of the gas and electricity markets started in the late 1980s. There are now no price caps or regulated prices in relation to wholesale gas and electricity in the GB electricity market. Temporary and targeted price caps are in place for specified retail products, these caps are therefore out of scope of Article 10 of Regulation (EU) 2019/943.	Implemented	-
Imbalance Settlement cash out reform	Ofgem will continue to monitor the impacts after the implementation the second phase of the modification.	Implemented & first phase reviewed	Electricity Balancing Significant Code Review
Increasing interconnection	In progress - 4.8GW of additional capacity is already in construction, and a further 6.1GW has been granted an initial regulatory approval under the Cap and Floor regime.	Significant increase in level of interconnection by 2030	Cap and floor regime: unlocking investment in electricity interconnectors
Removing barriers to electricity storage	Government will define electricity storage as a distinct subset of generation in primary legislation, when parliamentary time allows.	Intended by 2022	Upgrading out Energy System – Smart Systems and Flexibility Plan: Progress Update

	Government has committed to remove electricity storage, except pumped hydro storage, from the Nationally Significant Infrastructure Projects (NSIP) regime in England and Wales. This will make it simpler for large-scale storage facilities to seek planning permission. To achieve this, we will bring forward two statutory instruments; one order under the Planning Act 2008 and one order under the Electricity Act 1989. These began their passage through Parliament on 14 July, when the first order (under the Planning Act 2008) was laid before Parliament.	Implemented	The planning system for electricity storage: follow up consultation
	Ofgem have published modifications to the generation licence for storage. This will enable storage licence holders to avoid overpayment of policy levies.	In progress	Clarifying the regulatory framework for electricity storage: Statutory consultation on proposed modifications to the electricity generation licence
	Industry has raised a series of modifications to reform network charges for storage, so that storage does not overpay for use of the system. These are progressing through industry governance and the majority have been approved by Ofgem.	In progress	The details of the modifications can be accessed at the following links: CMP280, CMP281, CMP319, DCP341, DCP342 and P383
	Government has launched a health and safety governance group to ensure an appropriate, robust and future-proofed health and safety framework is sustained.	Implemented	More information on the health and safety governance group can be found in the Smart Systems and Flexibility Plan: Progress Update

	Industry are taking forward actions to ensure the network connections process is appropriate and does not present any undue burdens to storage.	In progress	-
Enabling the use of DSR in homes and businesses	Government is committed to rolling out smart meters to homes and small businesses in Great Britain.	In progress	Smart meter policy framework post 2020
	Enabling time-of-use (ToU) tariffs through the roll-out of smart meters. The first ToU tariffs were launched in 2017 & 2018.	In progress	-
	Introducing appropriate regulatory and technical requirements for certain smart appliances that are suitable for flexible consumer use, e.g. fridges and washing machines.	Intended by 2022	-
	Support the development of industry-led technical standards for energy aggregators and smart appliances, including electric vehicle (EV) charge-points, with the British Standards Institution.	In progress	BSI PAS Standards
Balancing services	GB Electricity System Operator (ESO) is taking forward actions to ensure a level playing for technologies and business models able to offer up services, and to support transparent and competitive markets.	In progress	Future of balancing services
	We have allowed independent aggregators to access the BM. The introduction of wider code modifications through the Trans European Replacement Reserves Exchange will open up the BM to a wider range of flexibility providers. The modifications have been approved by Ofgem.	Implemented	Project TERRE implementation into GB market arrangements

Enabling Self-generation	We introduced the Smart Export Guarantee (SEG) to ensure that small-scale generators have the right to be paid for the self-generated renewable electricity that they export to the grid.	1 January 2020	The Future for small-scale low carbon generation consultation response The future for small-scale low carbon generation: Part B consultation
Regulated pricing	The pre-payment meter price cap will remain in place until the end of 2020, after which the independent regulator (Ofgem) will consider whether any measures are needed to protect pre-payment meter customers going forward. The price cap on standard and default tariffs lasts until the end of 2020, with the option to extend annually up to 2023 if the conditions for effective competition are not in place.	Remains in place until the end of 2020. Remains in place until the end of 2020, or the end of 2023 at the latest.	-
The GB Capacity Market	Implementing the phase out of CM support for generation capacity that emit more than 550g of CO2 of fossil fuel origin per kWh of electricity, starting with new build capacity. We launched a consultation in July 2019 which considers proposals on how to implement the carbon emissions limit for existing and refurbished plant.	In July 2019 we implemented the limit for new build capacity in the CM.	These changes were implemented via the Capacity Market Amendment (No. 5) Rules 2019 Following the Consultation

	As recorded in the Commission State aid decision in 2019 the UK committed to implementing certain improvements to the scheme for the future.	We have implemented six of the seven commitments in the 2019 Capacity Market State aid approval.	State aid decision Capacity Market: Proposals for future improvements consultation and response

This publication is available from: www.gov.uk/government/publications/great-britain-electricity-market-implementation-plan

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