Memo to:
Cathy Fraser, National Grid ESO

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From:	DNV
Date:	24/05/2021
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SUMMARY

NGESO has engaged DNV to undertake an independent review of its commercial activity over the period April 2020 – January 2021, to ascertain whether its actions were proportionate and provided value to consumers. This review has been instigated by the atypically high costs that NGESO incurred in managing the transmission system throughout most of 2020 under the effects of the COVID pandemic.

Our assessment finds that NGESO has acted efficiently and effectively to address the system need within the boundaries of information and tools that were available given the high degree of uncertainty at times when actions were taken. We consider this finding reflects the agile, yet robust, process adopted by NGESO throughout 2020 to govern its actions during periods of low and unpredictable demand, on which we commented in our Summer Operability Review report of 8 August 2020.

DNV's analysis is based on data and process documentation provided by NGESO, as well as interviews with key members of NGESO staff that were involved. Based on the magnitude of total costs, the review focused on the following system management services:

- Constraint Management – Transmission;
- Constraint Management – Rate of Change of Frequency (RoCoF) & Vector Shift (VS);
- Optional Downward Flexibility Management (ODFM); and
- Sizewell de-load contract.

Whilst NGESO has coped with the challenging operational conditions well and allocated resources reasonably, the established processes and system operation services have resulted in high balancing costs. We do not expect this to change unless more fundamental strategic changes in the system and framework of services are made. DNV has identified a number of recommendations that focus on the mid and long-term, some of which NGESO is already considering within its Pathfinder projects and its newly published Constraint Management 5-point plan, whilst others are alternative solutions that we encourage NGESO to explore.

The immediate reason for the higher costs is a complex interplay of several factors: the extremely low demand driven by the COVID pandemic; high output levels of non-synchronously connected generation; loss of mains issues (obsolete G59 protection relays); and high wind generation output levels in autumn 2020 coinciding with longer periods of reduced network capacity in certain regions (Scotland and North England) due to outages.

We did not identify any material issues when considering costs associated with Transmission Constraints and subsequent analysis of the relevant commercial features (price, competitiveness, market depth). DNV finds that the actions that NGESO took to manage these Transmission constraints were justified, and the root cause of the high cost issues lies in the structure of the network and generation mix. Through the Connect and Manage policy, the connection of renewable generation has been enabled ahead of network reinforcement and these issues are likely to persist in a future with high share of renewables unless structural changes in the network are made. NGESO is aware of this and is exploring various reinforcement options together with the Transmission Owners (TOs) through the Network Options Assessment (NOA) process.

We also conclude that the approach to manage Rate of Change of Frequency (RoCoF) and Vector Shift (VS) risk is reasonable, and note that the precautionary measures are well justified considering the significant risk of potential disconnection of distributed energy generation during the periods of low inertia on system. We observe that the prices paid to manage RoCoF and VS risks are reflective of energy production costs and have generally followed the same trend as wholesale electricity prices.

We have recognised the need for the ODFM service and found that NGESO has conducted a thorough analysis on the alternative available measures before designing a new tool. Considering that ODFM was developed in a very short time, we find it an efficient measure that has provided benefits on a number of days where otherwise NGESO would likely resort to issuing Emergency Instructions (EIs). DNV considers that it would be more suitable to have a service that is evaluated and instructed closer to real time. We note that NGESO are aware of this and the ODFM service was meant as a temporal insurance policy under low and uncertain demand.

Finally, concerning the Sizewell de-load contract we have concluded that the rationale for entering into the contract, and extending it twice during the summer period, is sufficiently justified. Considering the range of uncertainties with regard to the volumes of downward flexibility that would be provided by ODFM and Super-SEL as alternatives, it was prudent and technically justified to establish a commercial agreement with Sizewell as the single largest unit on the system.

REVIEW CONTEXT AND APPROACH

Since March 2020, the drop in economic activity caused by the COVID-19 pandemic has resulted in unusually low system demand on the GB transmission system, and comparatively high generation from renewable energy sources, exacerbated by extreme windy conditions through the Autumn months. As a consequence, National Grid Electricity System Operator (NGESO) has had to take unprecedented actions to manage and maintain system operability, including the rapid development and deployment of new services, sometimes resulting in significant cost.

To ascertain whether it has provided best value to consumers, NGESO engaged DNV to undertake an independent review of its commercial activity over the period April 2020 – January 2021. As a starting point for this assessment, DNV discussed and agreed with NGESO to focus the review on high cost service schemes as well as newly introduced schemes. On this basis, we selected the following for review:

- Constraint Management services, focusing specifically on:
  - Congestion (Transmission) management services to accommodate outages requested by Transmission Owners (TOs); and
  - Frequency risk management due to loss of Mains protection including Rate of Change of Frequency (RoCoF) and Vector Shift (VS);
- Special measures to manage the impact of COVID-19, including:
  - Optional Downward Flexibility Management (ODFM); and
  - the Sizewell De-Load Contract.

For each of these, we have reviewed the basis for the intervention/action by NGESO and the end to end process for procuring, selecting, calling, and dispatching generation and/or demand capacity to meet the relevant requirement, by reference to a sample of high cost days. Our review seeks to determine whether

a) there was a reasonable need for the procurement or deployment of a service;

b) the process followed to procure and/or deploy a service is technically and economically sound;

c) any reasonable alternative solutions were available at the time; and

d) in the future, any possible refinements or improvements to relevant processes could be sought, or alternative solutions could be considered or developed.

This document summarises the outcome of the assessment and is an accompanying memo to the main report "*Operational Review"* of 26 April 2021, which provides our full underlying analysis.

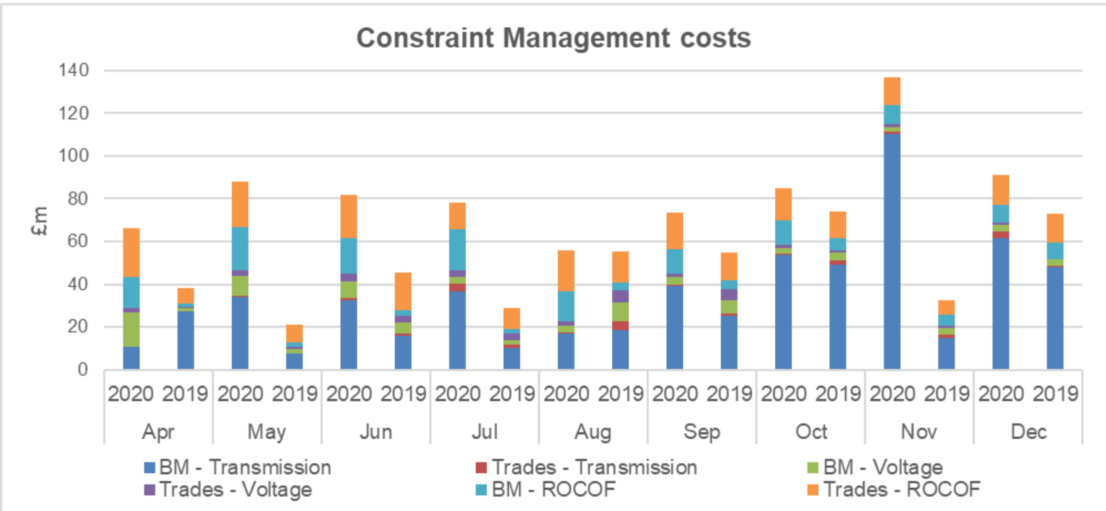
KEY REVIEW FINDINGS

CONSTRAINT MANAGEMENT

NGESO must ensure the security of the system which entails keeping operational parameters of the transmission system within prescribed limits according to SQSS[1] (Security and Quality of Supply Standard) requirements. These limits can be exceeded even when the overall system is in balance. Dispatch of generation and/or load driven by the market may not be technically feasible. Asset limitations (e.g. voltage and current levels) may form a constraint in regions where high power transfers occur. This can be further complicated when TOs request an outage in order to conduct essential maintenance or to replace or upgrade certain equipment, which effectively reduces available transmission capacity.

In order to manage these constraints NGESO may instruct generators and demand to turn up/down their production/consumption for a certain period, so that the overall balance of the system is preserved but corresponding power flows in the network are altered to stay within the limits.

NGESO divides constraints into three groups (1) Transmission / Thermal; (2) Voltage; and (3) RoCoF / Stability. The following figure presents overall Constraint Management costs for the period from April 2020 to January 2021, divided into two methods of procuring the service – Balancing Mechanism (BM) and Trade. The figure illustrates the increase in spend from 2019 to 2020, particularly for Transmission and RoCoF, which DNV has investigated as part of this assessment.



1 https://www.nationalgrideso.com/industry-information/codes/security-and-quality-supply-standards

TRANSMISSION CONSTRAINT MANAGEMENT

Below are the findings and our assessment from our review of constraint management actions undertaken by NGESO, by reference to the days we have investigated, reflecting on the operational background and geographic and weather-related factors, as well as NGESO's current service procurement mechanisms.

Background

- Throughout the period of the COVID-19 pandemic in 2020 (April 2020 – January 2021) NGESO incurred constraint management costs that are significantly higher than usual. The highest proportion of costs is attributed to Transmission management (54%). RoCoF and Voltage management accounted for 37% and 9%, respectively.
- The primary system drivers for these increased costs are low demand levels, a high penetration of non-synchronous generation (especially wind), and structural congestions in the transmission system. The interplay between these factors is complex and varies from day to day, and we consider it is this complexity and variability that leads to high system management costs, rather than a single factor throughout the entire period.
- On days with high wind output and reduced demand levels, NGESO has needed to actively intervene in the system management to ensure a secure operation of the transmission system. The reason is that on such days:
    - The network may not be physically capable to carry the power transfer from generation to demand centres,
    - The inertia level in the system becomes too low, raising the risk of unacceptable frequency conditions due to the increased risk of loss of mains protection settings being triggered and disconnecting distributed energy resources (DERs).
- Furthermore, the presence of planned and/or unexpected outages can exacerbate the system's capability to transfer power from supply to demand, resulting in higher constraint management costs.

Geographic and weather factors

- Load centres are concentrated in the south of GB (England and Wales), whilst wind generation is predominantly located in the north (Scotland). On windy days, a majority of conventional units spread across GB will not self-dispatch as a result of market clearing. Since conventional synchronously connected units are not dispatched, NGESO has less flexibility in the number and diversity of service providers that it can engage to manage the system. Often the solution is to curtail wind generation, at a high cost to NGESO.
- The vast majority of transmission management costs can be geographically attributed to outages in Northern England and Scotland. Here, system boundaries are approaching thermal capability limits, while further wind growth in the region is planned. We find this to be in line with the expectations that NGESO develops under the NOA process.

Procurement mechanisms

- Most transmission constraint management costs (~97%) are incurred through the BM, with Trades only constituting ~3%. The main reason is that the BM allows NGESO to reach to a larger amount of market participants close to real time. This is an important factor in transmission management which requires ramping up/down a large number of assets within a certain region – it is technically not feasible to instruct these assets through trading. We consider that the difference in accrued costs is reflective of a fundamental distinction between two mechanisms serving different needs.

- Considering the market structure and variety of service providers, we have not found any indication of market distortions or anticompetitive pricing, noting that the BM is competitive and facilitates most of the services procured (in terms of total volume and costs).
- The average costs per MWh of service procured are in line with average wholesale market prices and followed a similar trend. Nevertheless, we observe higher costs per volume in periods of the year characterised by a large share of wind energy in the generation mix. This trend is even more pronounced in areas with structural transmission constraints, such as Northern England and Scotland.

Findings from our assessment

- DNV considers that the short-term actions that NGESO undertook to manage the system are reasonable, given the operational conditions and availability of constraint management tools. On days of atypically high expenditure, we consider NGESO has taken efficient actions that ensured system security in congested areas.
- For the medium term, DNV recommends that NGESO continues to consider how outage planning (due to maintenance or new asset connection needs) in Northern England and Scottish regions takes into account long-term or probabilistic (based on historic data) wind forecasts. Whenever possible within the need for TOs to deliver certain reinforcements in a given timeframe, and in cooperation with those TOs, NGESO should seek to steer planned outages in that region to be allocated to less windy periods of the year.
- In the long-term, however, we consider these actions are not likely to be sufficient and will continue yielding high system management costs. Further measures are required to keep system management costs to a minimum, and should aim at securing the system under a low inertia level with high concentration of generation and demand in geographically distant regions:
    - In particular, reinforcement on the Northern England and Scottish boundaries is needed to reduce extreme constraint management costs across SSHARN3 (B7a) and SSEN-S (B2). We understand that NGESO interacts with TOs under the Network Options Assessment (NOA) programme aimed at the identification of the optimal system reinforcement projects.
    - Coordinated planning of offshore connections in a way that supports the need of the onshore system. This is particularly relevant for large offshore windfarms being developed in the North. In 2020, DNV supported NGESO with its Offshore Coordination study identifying that a coordinated approach to offshore grid design could bring operational benefits to onshore grid management. NGESO should continue their exploration in this direction and keep articulating the potential benefits among the relevant stakeholders.[2]
    - Other potential solutions to be explored with industry and ESO, through the Constraint Management Pathfinders (e.g. large-scale energy storage, such as inverse pump accumulation systems and/or conversion from surplus of electricity to hydrogen).
- We note that NGESO published a new 5-point plan in March 2021[3] to manage transmission constraints and associated costs going forward, covering a number of the suggestions above.

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2 https://www.nationalgrideso.com/future-energy/projects/offshore-coordination-project

3 Our 5-point plan to manage constraints on the system | National Grid ESO

FREQUENCY RISK MANAGEMENT

This section sets out the findings of the cost assessment and process assessment, respectively, in relation to RoCoF.

Cost Assessment

Annual expenses for managing RoCoF in 2020 amounted to double the expenditure for 2019. In particular, BM costs increased significantly by around 253% from £35.4m in 2019 to £124.9m in 2020. Trade costs showed an increase of 49% from £103.9m in 2019 to £154.4m in 2020.

- This large increase in RoCoF management costs is mainly triggered by unusually low power demand (due to COVID-19) in combination with windy days, which resulted in low inertia and insufficient synchronous generators on the grid to cope with the potential loss of a large unit. In addition, spring 2020 was one of the warmest on record, which further lowered demand. Consequently, additional synchronous power units had to be mobilized in the BM to provide sufficient inertia on the grid.
- Certain actions, such as adding synchronous generation, cannot be done efficiently via the Trade mechanism and NGESO therefore uses the BM to competitively acquire the necessary actions to increase system inertia. Focusing on the high costs of RoCoF management, we observed that most expenditure growth is related to BM actions, which reflects that BM actions come at a higher cost per volume than Trade interventions.
- Overall, the prices of the RoCoF service (cost/volume procured) have followed the evolution of wholesale electricity prices through the pandemic period. Total RoCoF costs also displayed some seasonality triggered by the overall lower demand and consequential lower inertia during summer, in combination with an additional decline in demand due to COVID-19 and a high influx of non-synchronous wind power. Taken together, these developments make power system equipment more prone to reacting inadequately in the case of a potential RoCoF event and thus we consider it logical that more actions were required to manage RoCoF.
- On the supply side, 74.6% of the total costs incurred for RoCoF services can be attributed to three power stations (Humber Refinery, Saltend and South Humber bank). NGESO is forced to take targeted actions on these units to reduce the N-1 risk, which is the primary action used to manage RoCoF and cannot be substituted by actions involving other units. Based on the specific characteristics some power stations are more often accessed via Trade (Humber Refinery) and others via BM (South Humber bank).
- Providing inertia via synchronous generators was common on high cost days, whereby almost half of the annual expenditure of adding synchronous generation was incurred during the 10 highest cost days. The combination of low load and high wind generation resulted in insufficient inertia on the system and, therefore, adding synchronous units was the only option available to NGESO. Nevertheless, on an annual basis the cost for mobilizing synchronous generators to increase inertia only represented 8% of the total RoCoF management costs.
- The adoption of generator units which updated their control systems as a result of the Accelerated Loss of Mains Change Programme (ALoMCP) is expected to reduce overall RoCoF management costs in the future. According to the NGESO team, the effects of the ALoMCP, although already visible in 2020, are expected to have the first significant impact this summer (2021) due to many solar PV based DERs being updated to the new relay standards. As a result, we consider that the risk of a RoCoF event triggered by obsolete G59 relays will be significantly decreased as more units adopt the ALoMCP program.

Process Assessment

Our main findings regarding the approaches NGESO follows to manage RoCoF risk and/or take necessary action are as follows:

- We understand NGESO is introducing a new "Frequency Risk and Control Report", with a probabilistic approach instead of the current deterministic approach around RoCoF risks. This takes into account both the likelihood of such an event, as well as the costs to secure the event. With this risk based, probabilistic approach, NGESO expects that large units such as Humber Refinery, Humber Bank and Saltend will not be ramped down to reduce the size of the largest trip size. This change is formalized in modification SQSS GSR027. We concur with this change in approach, since it can be expected to reduce overall RoCoF management costs in the future (in addition to anticipated cost reductions delivered through the ALoMCP).
- A large share of the yearly costs for RoCoF relate to the Humber Refinery, Humber Bank and Saltend power stations, all of which had to be de-loaded on a near-daily basis. Based on the guidelines and documentation provided by NGESO, we understand that under the prevalent operational circumstances this was a "must" (reducing the size of the largest plant), reflecting SQSS and NGESO licence requirements.

DNV considers that the actions taken by NGESO were necessary to remain within the RoCoF trigger limit, as well as to ensure there would be sufficient inertia on the system. Our overall view on RoCoF is that NGESO follows a sound process and can reasonably be said to act efficiently and effectively in managing RoCoF risk.

We observe that RoCoF costs, as part of NGESO's total costs for system operation, are high. The general trend towards more generation without inertia will continue. Therefore, we recommend NGESO to continue to actively pursue the development of other cost-effective means to handle the issue – and we observe this is being directly addressed with the FRCR and launch of Dynamic Containment as well as further exploration through the NOA Stability Pathfinder initiative.[4]

SPECIAL MEASURES TO MANAGE THE IMPACT OF COVID-19

In the spring of 2020, during the first COVID-19 lockdown, load on the transmission system was extremely low and almost exclusively being met by inflexible nuclear and renewable generation. NGESO anticipated low demand would persist during the summer period, alongside an increasing need for actions to manage inertia and other operability issues (related to stability, voltage, thermal, restoration and frequency). However, the ongoing dominance of large, inflexible generation would mean that NGESO's usual toolkit of commercial services would be severely diminished or ineffective, increasing the potential need for (costly) Emergency Instructions (EIs) to generators.

To tackle this challenge, NGESO sought to acquire additional downward flexibility. For that, NGESO investigated the implementation of different services that could serve the purpose on a short time frame[5]:

- Demand turn up (DTU);
- Super SEL contracts;
- Nuclear de-load contracts;

4 https://www.nationalgrideso.com/future-of-energy/projects/pathfinders/stability

5 RAPID Decision paper Downward Flexibility Management for Summer 2020, NGESO, April 17th, 2020

- Instruct wind farms to operate as demand;
- Day ahead manual downward flexibility service;
- Accessing existing DNO flexibility markets;
- Within day flexibility service for non-BM providers via PAS (platform for ancillary services); and
- Sign up more Schedule 7a Wind Trades.

NGESO decided to proceed and progress with the services: Super SEL contracts, Nuclear de-load contracts, Day ahead manual downward flexibility service, and Access to DNO flexibility markets. The rejected services required longer implementation timescales than were available, provided access to assets accessible via other accepted services, or implied a risk to undermining other services. The possibility of not implementing a new service and continue with the already available options was rejected as it implied the use of EIs which goes against NGESO policy.

In the following sections we analyse two of the implemented services, Optional Downward Flexibility Management (ODFM) Service, and the de-load contract with Sizewell nuclear power station.

ODFM

Motivation for the service

- ODFM was implemented to ensure sufficient downward flexibility, i.e. having the ability to decrease production or increase demand to manage the uncertainty in what the actual imbalance will be. As investigated in the Summer Operability Review[6], National Grid ESO performed studies of the system under stress to look at the impact of a worst-case scenario in order to be prepared for the challenging summer low load situation.
- ODFM service can also have other positive effects in terms of system security on the days of activation. The reduction of the production from small scale renewable generators, or increase in demand, resulting from the ODFM instructions, is replaced with units that can provide negative reserve and are accessible via the BM.
- Prior to proceeding with the ODFM service, NGESO looked into other potential alternatives like accessing existing DNO flexibility markets, instruct windfarms to demand, and Nuclear de-load contracts. We find that NGESO carried out a reasonable investigation to determine if there would have been other alternatives available.

Operational conditions that induced the ODFM instruction

ODFM was activated on days with forecasted low demand and high renewable generation. Due to the assumed energy mix, and depending on different requirements, the available negative reserve options were not sufficient to meet the imbalance, in addition to the negative reserve requirements for the specific time. In light of the lack of alternatives, and the fact that NGESO only activates ODFM if they see no other option to feel confident that EIs can be avoided, we consider the activation to be reasonable.

Decision process & service configuration

- Before the decision to activate ODFM, NGESO presented its strategy to representatives from different relevant groups within the company. The decision was also taken in steps with refined forecasts which would reduce uncertainty, and thus risk of overspending, as much as possible.

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6 Report - Summer Operability Review, DNV for NGESO, August 11th, 2020

- As per its published assessment principles,[7] NGESO calculates an effective price based on its estimates of load factors and ranks bids based on their effective price. We consider this method to be reasonable. The use of a day-ahead service entails certain levels of uncertainty induced by the accuracy of the forecast data and assumptions used for the decision of ODFM instruction, i.e. if the ODFM need is reduced due to higher demand or high availability of BM actions on real time, the contracted ODFM volume cannot be changed. The extent to which BM products could be more economic than ODFM cannot be directly compared and determined, as the payments for the two products have different bases and the forecast of BM costs lacks accuracy for events like COVID-19.
- It would be more suitable to have a service that is evaluated and instructed closer to real time. From the information provided by NGESO, we observe that they are aware of this and the ODFM service was meant as a temporary measure. NGESO expressed the idea that a product like ODFM, with availability in the same timescale as the BM actions, would be a more suitable configuration. NGESO is conducting a consultation to design an enduring service to provide negative reserves. This work is performed within the Reserve Reform and is testament to NGESO's desire to create a long-term solution.
- NGESO have advised that as ODFM was introduced and utilised, more information and data was readily and robustly available, to inform subsequent instruction decisions. This facilitates future review processes, as well as providing a more detailed view on the conditions that can result in a need for a service like ODFM.

Negative reserve margin requirement

- Regarding the margins chosen to facilitate downward flexibility, we consider that this reflects willingness to pay versus the risk of a material system failure. Given the fact that there was a lot of uncertainty related to the unprecedented lock-down situation and an energy mix, it is understandable that extra margins were added.
- We consider it sound that NGESO has performed internal retrospective analysis to evaluate whether the extra margin added for the negative reserve (the negative contingency) was necessary. Looking forward to the potential use of ODFM during the Summer 2021, a study including a more complete dataset for demand (lack of data was a known weakness for the 2020-analysis) was performed. Based on this study it was suggested that whilst 1 GW is still reasonable at a decision time about 48 hours ahead, the ESO internal Energy Steering Group may wish to consider reducing the negative contingency to 500 MW for a decision about 24 hours ahead of the actual activation of the negative reserve.
- We understood that as time went on, NGESO gained more confidence in how it would tackle the uncertainty, and which assumptions were reasonable regarding e.g. the availability of other negative reserve alternatives and thus, improved the process before decision. We find the process of improvement with experience to be commendable.

Overview

Given the time frames for finding a solution that could provide the capacity needed, we have not found any unduly high costs. We do, however, support NGESO's decision to continue improving the service towards an availability in the same timescale as BM actions and with similar commercial conditions. We

[7] ODFM Interactive Guidance Documents - https://data.nationalgrideso.com/backend/dataset/812f2195-4e96-4bfd-8bf0-06c3d0126c57/resource/890c4ac5-5513-4513-a7be-553ecc902ccf/download/odfm-interactive-guidance-version-1.1.pdf

encourage NGESO to continue its work to increase the participation from other flexibility resources, like flexibility from smaller customers via aggregators.

SIZEWELL DE-LOAD CONTRACT

- DNV considers the basis for NGESO to enter into the Sizewell de-load contract, as well as its execution of this contract, to be reasonable. The main driver for developing a commercial solution to the risks associated with the extraordinarily low system load at the height of COVID-19 measures was to avoid a significant risk of having to resort to emergency measures. DNV subscribes to this driver as a fundamental principle underpinning the duties of a system operator.
- Having established the need for a commercial solution, NGESO, in our view, undertook a reasonable process to assess the feasibility of alternative solutions, both existing and new, arriving at the conclusion that none were (reliably) feasible. We understand the basis for targeting Sizewell specifically was because not only would a Sizewell de-load meet the technical requirements, it would bring the added benefit of managing a significant large loss risk, as well as generating cost savings in the procurement and deployment of other operational measures. We do note that further economic benefits associated with avoidance of a large-scale outage were considered, but not evidenced, at this stage.
- DNV also considers that the basis for the initial contract with Sizewell is reasonable, since it was based on the principle that EDF would recover reasonable costs, employed break clauses to enable assessment of the ongoing need and feasibility of the service, and NGESO explored more flexible ways of contracting Sizewell (which were ultimately not technically feasible).
- The cost benefit analysis (CBA) initially performed covered the full contract duration and showed continued benefit for all phases of the Sizewell contract, although no further CBA was carried out at the points the contract was extended.

We conclude that in relation to the Sizewell contract NGESO has acted in accordance with its remit under Standard Licence Condition C16 and it has clarified the basis for future interventions through SQSS modification.