Network Options Assessment Report Methodology

Electricity System Operator

July 2019

Version	Final 5.1
Date	26/07/2019

About this document

This document contains National Grid Electricity System Operator (ESO)'s Network Options Assessment (NOA) report methodology established under the Electricity Transmission Licence Standard Condition C27 in respect of the financial year 2019/20. It covers the methodology on which National Grid ESO, will base the NOA which will be published by 31 January 2020. As the methodology evolves due to experience and stakeholder feedback, the methodology statement will be revised for subsequent NOAs as required by Licence Condition C27.

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Introduction

Purpose

1.1 The purpose of the Network Options Assessment (NOA) is to facilitate the development of an efficient, coordinated and economical system of electricity transmission consistent with the National Electricity Transmission System Security and Quality of Supply Standard and the development of efficient interconnection capacity.

1.2 This document provides an overview of the aims of the NOA and details the methodology which describes how the Electricity System Operator (ESO) assesses the required levels of network transfer requirement, the options available to meet this requirement and the ESO's recommended options for further development. It is important to note that whilst the ESO recommends progressing options in order to meet system needs, any investment decisions remain with the Transmission Owners (TOs) or other relevant parties as appropriate.

1.3 This methodology document describes the end to end process for the analysis and publishing of the NOA report and identifies the roles and responsibilities of the ESO and TOs.

1.4 Where this methodology refers to 'TOs', it means onshore TOs.

Key changes for 2019/20

1.5 We launched our Network Development Roadmap consultation[1] in 2018 and confirmed our direction of travel for the NOA for the following three years[2]. This focuses on developments that should drive additional value to consumers and includes extending the range of needs the NOA approach applies to and the participants and options that can be put forward. We are building the capability and testing the value through a number of pathfinding projects. Where relevant we intend to include any applicable options in the 2019/20 economic analysis. We report the pathfinding projects separately on our Network Development Roadmap website[3] and through the Electricity Networks Association (ENA) Open Networks Project[4].

1.6 We completed phase 1 of our high voltage regions pathfinding project in 2018/19 and the findings are published on the ENA website[5]. In this first step, we have identified the reactive requirements in the Pennines region and are working with relevant stakeholders to find the most cost effective way to meet those requirements. For the first time we now include the assessment of high voltage regions as part of the NOA methodology. This assessment is conducted on an annual basis and published independently of the NOA report.

1.7 The NOA 2018/19 recommended investment in two ESO-led commercial solutions. We are refining our requirements and assumptions for those solutions so they can be better represented in our assessment. The ESO is keen to encourage commercial solutions providers to support our obligations for operating the system.

1.8 We are also enhancing and evolving the way we undertake our analysis. We recognise that the most challenging system needs are no longer just at the winter peak demand background. This is mainly due to ever increasing level of interconnections and renewable energy resources which bring greater volatility and intermittency to generation and demand patterns. As the energy background evolves, using a deterministic approach based on winter peak conditions to identify year-round system requirements may result in an overly optimistic or pessimistic view of system needs. As such we have conducted a case study of the use of probabilistic analysis to identify year-round thermal requirements for a region of the network

[1] https://www.nationalgrid.com/sites/default/files/documents/Network%20Development%20Roadmap%20consultation.pdf

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

[3] https://www.nationalgrideso.com/insights/network-options-assessment-noa/network-development-roadmap

[4] https://www.energynetworks.org/electricity/futures/open-networks-project

[5] http://www.energynetworks.org/assets/files/ON-WS1-P1%202018%20Investment%20Planning%20Processes%20-%20Approach%20vFinal.pdf

where the system flows are considered volatile. This provided a comparison against our current approach. The report of the case study was published in the first quarter of 2019[6].

1.9 For the NOA 2019/20, we intend to use the probabilistic tool and techniques to assess the credibility of the network assumptions used in the boundary analysis and results provided by the TOs when year-round conditions are considered. To further develop our capability and experience in probabilistic network assessment, we intend to study all boundaries for the NOA year 1 analysis. We will also select one or several boundaries on which to perform year-round analysis for all NOA study years.

1.10 Following major changes to the SRF template in 2017/18, and subsequent feedback following use in the 2018/19 process we have refined the template. This takes into account the feedback received and aims to deliver a smoother handover process of information for this cycle.

1.11 For this year's NOA IC, we continue to evolve the methodology based on stakeholder feedback. We have refocused the work on the core iterative analysis and will revise the interconnector baseline level to provide a lower level of interconnection, as requested by stakeholders.

Key similarities to 2018/19

1.12 The overall NOA process and philosophy are the same as used last year. Our NOA Methodology review that we submitted to Ofgem in March 2017 concluded that single year regret analysis is the best way to evaluate the needs of the national electricity transmission system. You can find the review document at https://www.nationalgrid.com/sites/default/files/documents/NOA%20Methodology%20Review%202017.pdf.

1.13 For the NOA 2018/19, we continued to operate the NOA Committee to provide additional scrutiny throughout the NOA process. They brought expertise from different parts of the ESO to ensure that the NOA recommendations are robust and in the best interest of GB's consumers. You can find the minutes of the past NOA Committee meetings on the NOA webpage at https://www.nationalgrideso.com/insights/network-options-assessment-noa. The NOA Committee will continue for the NOA 2019/20.

Background

1.14 In order to recommend options, the ESO uses the established investment recommendation process. This ultimately leads to the selection of recommended options based upon their capital investment and constraint savings across a range of scenarios. Constraint costs are a factor of bid/offer prices and the amount of generation constrained. Both factors vary across the scenarios resulting in no one scenario necessarily seeing higher constraint costs than another.

1.15 The ESO performed seasonal validation checks for boundaries assessed in the first NOA report. The constraint cost modelling tool (ELSI at that time) used assumptions to scale the boundary capabilities across seasons. It scaled the capabilities from the winter reference values to values for other seasons and also for outages. The purpose of the seasonal validation checks was to see how the scaled values compared with the values from technical studies of the same boundaries. The validation checks showed that the assumptions were broadly correct and needed only slight adjustment. Appendix B gives a more detailed review of the seasonal validation checks.

1.16 This methodology describes the process and the headers used follow the flow diagram in Appendix C for clarity. Appendix D contains the SRF template; Appendix E is the cost checking process; and Appendix F is the form of the NOA report.

[6] https://www.nationalgrideso.com/document/140781/download

1.17 In accordance with Standard Licence Condition C27, the ESO has sought the input of stakeholders. Appendix G includes a summary of any views that the ESO has not accommodated in producing this NOA report methodology.

Differences between NOA and ETYS

1.18 The NOA process is the ESO's licence obligation as required by Electricity Transmission Standard Licence Condition C27 (The Network Options Assessment process and reporting requirements). Specifically, paragraph 15 defines the required contents of the NOA report, which are the ESO's best view of options for reinforcements for the national electricity transmission system together with alternatives and recommended options.

1.19 The Electricity Ten Year Statement (ETYS) is the ESO's licence obligation as required by Electricity Transmission Standard Licence Condition C11 (Production of information about the national electricity transmission system). Paragraph 3 defines ETYS's required contents which are the ESO's best view of the design and technical characteristics of the development of the national electricity transmission system and the system boundary transfer requirements.

1.20 In summary, ETYS describes technical aspects of the system and the system's development while NOA describes options for reinforcement to meet system needs.

The methodology

1.21 The Network Options Assessment (NOA) process set out in Electricity Transmission Standard Licence Condition C27 facilitates the development of an efficient, coordinated and economical system of electricity transmission and the development of efficient interconnection capacity. This NOA report methodology has been developed in accordance with Standard Licence Condition C27.

1.22 This document defines the process by which the NOA is applied to the onshore and offshore electricity transmission system in GB. The process runs from identifying a future reinforcement need, to assessing available options to meet this need, to recommending and documenting the option(s) for further development. It also defines the process of assessing the suitability of recommended options for competition in onshore electricity transmission. This assessment is against criteria defined by Ofgem in their document Guidance on the Criteria for Competition[7]. The ESO identifies and evaluates alternative options such as those based around commercial arrangements or reduced-build options in addition to those provided by the TOs. on page 17 covers these alternative options in more detail.

1.23 The ESO has engaged with the TOs to develop this methodology statement. Following publication of the NOA report, further stakeholder engagement is undertaken to inform the methodology statement for supporting subsequent NOA reports.

1.24 As background information changes and new data is gained, for example in response to changing customer requirements, both the recommended options and their timing will be updated, driving timely progression of investment in the electricity transmission system.

1.25 The ESO engages stakeholders on the annual updates to the key forecast data used in this recommendation process, and shares the outputs from this process through the publication of the NOA report.

1.26 Transmission Licence Standard Condition C27 Paragraph 15 sets out the contents of the NOA report. The licence condition is undergoing consultation and review[8] but this process will finish after the NOA methodology is submitted to Ofgem. We will take a view on reviewing the NOA methodology once the revised licence condition is published.

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[7] https://www.ofgem.gov.uk/system/files/docs/2019/02/criteria_guidance.pdf

[8] https://www.ofgem.gov.uk/publications-and-updates/statutory-consultation-modify-standard-condition-c27-electricity-transmission-licence

> Each NOA report (including the initial NOA report) must, in respect of the current financial year and each of the nine succeeding financial years:
>
> (a) set out:
>
> (i) the licensee's best view of the options for Major National Electricity Transmission System Reinforcements (including any Non Developer Associated Offshore Wider Works that the licensee is undertaking early development work for under Part D), and additional interconnector capacity that could meet the needs identified in the electricity ten year statement (ETYS) and facilitate the development of an efficient, co-ordinated and economical system of electricity transmission;
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> (ii) the licensee's best view of alternative options, where these exist, for meeting the identified system need. This should include options that do not involve, or involve minimal, construction of new transmission capacity; options based on commercial arrangements with users to provide transmission services and balancing services; and, where appropriate, liaison with distribution licensees on possible distribution system solutions;
>
> (iii) the licensee's best view of the relative suitability of each option, or combination of options, identified in accordance with paragraph 15(a)(i) or (ii), for facilitating the development of an efficient, co-ordinated and economical system of electricity transmission. This must be based on the latest available data, and must include, but need not be limited to, the licensee's assessment of the impact of different options on the national electricity transmission system and the licensee's ability to co-ordinate and direct the flow of electricity onto and over the national electricity transmission system in an efficient, economic and co-ordinated manner; and
>
> (iv) the licensee's recommendations on which option(s) should be developed further to facilitate the development of an efficient, co-ordinated and economical system of electricity transmission;
>
> (b) be consistent with the ETYS and where possible align with the Ten Year Network Development Plan as defined in standard condition C11 (Production of information about the national electricity transmission system), in the event of any material differences between the Ten Year Network Development plan and the NOA report an explanation of the difference and any associated implications must be provided; and
>
> (c) have regard to interactions with existing agreements with parties in respect of developing the national electricity transmission system and changes in system requirements.

1.27 References to 'weeks' in the NOA report methodology are to calendar weeks as defined in ISO 8601. Week 1 is at the start of January and is the same as the system used the Grid Code OC2.

Major National Electricity Transmission System Reinforcements

1.28 Standard Licence Condition C27 Section C refers to the term Major National Electricity System Reinforcements for the purpose of this NOA report methodology statement. The definition has been agreed from consultation with the onshore TOs and the Authority (Ofgem) as:

Major National Electricity Transmission System Reinforcements are defined by the ESO to consist of a *project or projects in development to deliver additional boundary capacity or alternative system benefits as identified in the Electricity Ten Year Statement or equivalent document.*

1.29 The intention of this definition is to maximise transparency in the investment decisions affecting the National Electricity Transmission System while omitting schemes that do not provide wider system benefits. Such as schemes for a user connection or to improve system reliability.

Eligibility criteria for projects for inclusion / exclusion

1.30 The NOA report presents projects as options to reinforce the wider network that are defined by Major National Electricity System Reinforcements (see definition above).

1.31 The ESO provides a summary justification for any projects that are excluded from detailed NOA analysis.

1.32 Once a Strategic Wider Work (SWW) Needs Case has been approved by Ofgem, the option is excluded from the NOA analysis although the report refers to it and it is included in the baseline. This is due to it being managed through the separate SWW process. Ofgem have agreed the approach of excluding options where they have already agreed the SWW Needs Case. The NOA report will include analysis of options under construction that are funded through the incremental wider works (IWW) mechanism.

Roles and responsibilities of ESO and TOs

1.33 The ESO role and responsibilities are based around its overview of the network requirements. Specific role areas are as follows:

- analysis of UK FES data
- devising and developing alternative options including operational options, commercial agreements and Offshore Wider Works (OWW)
- identifying boundary transfer requirements and issuing SRFs to TOs
- verification studies of some boundary analysis performed by the TOs to corroborate the TOs' analysis
- review of reinforcement options and their cost estimates that the TOs propose
- assessment of outages and other system access availability that might affect the options' Earliest in Service Dates (EISD)
- running cost-benefit analysis studies
- recommending options for further development
- assessing eligibility for competition
- advise on the performance of boundary reinforcement proposals in the cost-benefit analysis to facilitate further option development by the TOs
- providing an explanation of the NOA Committee recommendations
- recording details if a TO does not follow a NOA recommendation
- producing and publishing the NOA report.

1.34 The TOs' roles and responsibilities include:

- technical analysis of boundary capabilities of the base network and uplifts from reinforcement options
- proposing and developing reinforcement options and reduced-build options and providing their technical information to the ESO
- cost information for options
- outage and system access requirements for options
- environmental information for options
- consents and deliverability information for options
- EISD of options
- stakeholder engagement (following review of draft outputs of the NOA outcome)
- community engagement
- review of the draft NOA report and appendices relating to TO options.

Stakeholder consultation

1.35 The ESO has consulted with the TOs and Ofgem whilst preparing this NOA report methodology and used webinars and other meetings to seek other parties' inputs.

1.36 The key consultation areas are the NOA methodology, form of the NOA report and the NOA report outputs and contents.

1.37 This section shows the timescales for the ESO's consultation of stakeholders during the period of writing the NOA report.

Methodology review

1.38 The ESO seeks stakeholder views annually for consideration and where appropriate implementation before the NOA process starts its annual cycle.

1.39 Following the final publication of the NOA report, the ESO undertakes an internal review of the NOA process. This is completed within 18 weeks of the publication of the NOA report with the publication of an updated NOA methodology. This is then open for stakeholders' consultation where comments/feedback are invited. The consultation will close six weeks after the methodology is published for consultation. The ESO considers these comments for a revised NOA methodology and submits the methodology to Ofgem by 1 August of that year.

1.40 The ESO seeks approval from the Authority (Ofgem) on the NOA report methodology and form of the NOA report as part of the annual stakeholder engagement process.

Report output

1.41 The ESO makes available selected parts of the pre-release NOA report to key stakeholders, particularly the relevant TOs, on a bilateral discussion basis to ensure confidentiality obligations. This is as the NOA report is being written based on assessment data, particularly economic data, becoming available. These discussions will occur as results become available and the report is being drafted.

1.42 Further key stakeholder engagement occurs with release of drafts of the NOA report, three weeks ahead of publication. This provides a final opportunity for stakeholders to comment on the NOA report and raise any significant concerns. When a stakeholder expresses concern with the conclusions of the report, a comment is incorporated in the relevant section(s).

Provision of information

Engagement with interested parties to share relevant information and how that information will be used to review and revise the NOA methodology

1.43 The NOA methodology and NOA report adequately protects any confidential information provided by stakeholders or service providers, for example, balancing services contracts. For this reason, this methodology seeks to be as open and transparent as possible to withstand scrutiny and provide confidence in its outcomes, while maintaining confidentiality where necessary.

1.44 In accordance with Licence Condition C27 Part C, the ESO provides information to electricity transmission licensees, interconnector developers and to the Authority (Ofgem) if requested to do so. The ESO will assist TOs with cost-benefit analysis for SWW Needs Cases. Where appropriate the ESO can use the NOA results as part of a SWW initial Needs Case with the agreement of the relevant TO(s).

Future developments

1.45 The ESO expects the following changes and developments in the NOA report methodology and process as it evolves:

- Building on the pathfinding projects to test distribution solutions as NOA options including identifying non-MW requirements and the necessary cost-benefit analysis methodology.
- Further refinement of the process for ESO-led options building on our experience.
- Modification of the process for assessing eligibility for competition taking into account developments in the legislative framework and our experience with assessments to date.
- Probabilistic tools that would need a high level of automation and facilitate:
    i. Year-round (24/7/365) consideration of a wide range of possible patterns for demand and generation to ensure that potential operational issues are discovered and also understood on the basis of the likelihood of that condition occurring (such as varying mixes of renewable generators, for example, wind and solar PV on a regional basis)

ii. Automated optimisation of power flow controllable devices (e.g., Quad Boosters (QBs) and other similar Flexible AC Transmission System (FACTS) devices)

iii. Automation of study set-up and contingency analysis

iv. Automated data manipulation and results handling and filtering.

Our current work led to a thermal probabilistic case study to investigate the concept that aims to assess the viability of using probabilistic tools for thermal studies in the year 2019. This was published in March 2019. Having gained experience with thermal studies, which includes performance levels and validation, we envisage voltage and any other elements would follow in the subsequent two years.

2

The NOA report process

Overview of the NOA report process

2.1. gives an overview of the NOA report process. This methodology describes how the ESO, working with the TOs, carries out these activities. The process diagram in Appendix C gives more details. The headers in this methodology follow the stage names in the process diagram in Appendix C.

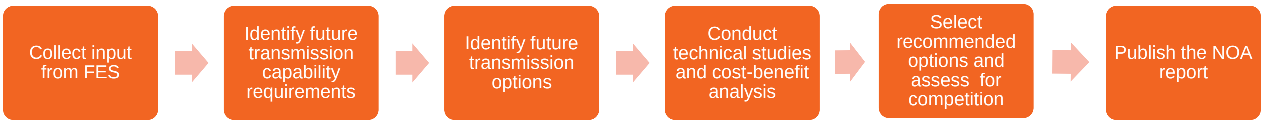


Figure 2. 1 Overview of the NOA report process

Collect input

Updated Future Energy Scenarios (FES)

2.2. The relevant set of scenarios as required by Electricity Transmission Standard Licence Condition C11, is used as the basis for each annual round of analysis. These provide self-consistent generation and demand scenarios which extend to 2050. The FES document is consulted upon widely and published each year as part of a parallel process.

2.3. The NOA process utilises the scenarios as well as the contracted position to form the background for which studies and analysis is carried out. The total number of scenarios is subject to change depending on stakeholder feedback received through the FES consultation process. In the event of any change, the rationale is described and presented within the FES Stakeholder Feedback Document[9] that is published each year.

2.4. FES 2019 will retain the scenario framework that was created following extensive analysis and consultation for FES 2018. We consider that this framework remains appropriate and that it also aligns with a call from our stakeholders for consistency to allow year-on-year comparison of our scenarios.

- We will therefore retain four scenarios in a 2x2 matrix structured around the axes of 'level of decentralisation' and 'speed of decarbonisation'.
- Two of the scenarios will meet the 2050 carbon emissions reduction target, with the other two showing slower progress, reflecting current obligations and highlighting the potential challenges.
- The scenarios will continue to reflect a mix of technology options, taking account of the rapid changes in the energy industry, markets and consumer behaviour.
- Security of supply for both gas and electricity will be achieved across all our scenarios for 2019.

2.5. The FES Scenarios are created by using a mix of data sources, including feedback from the FES consultation process. The scenario demands are then adjusted to match the metered average cold spell (ACS)[10] corrected actual outturns against which generation is applied to ensure security of supply can be met.

[9] See http://fes.nationalgrid.com/media/1397/2019-stakeholder-feedback-document-published-v10-010319.pdf for the FES Stakeholder Feedback Document and, for more general FES information, on our website http://fes.nationalgrid.com.

[10] The average cold spell (ACS) is defined as a particular combination of weather elements which give rise to a level of peak demand within a financial year (1 April to 31 March) which has a 50% chance of being exceeded as a result of weather variation alone.

2.6. Using regionally metered data, the “ACS adjusted scenario demands” are split proportionally around GB.

2.7. Based on the FES, there will be instances in the future where the available output of zero marginal cost generation such as nuclear and renewables will exceed demand, available storage and interconnection capacity. In these cases, the NOA economic model must choose which electricity source to be out of merit (referred to as ‘curtailment’ in the NOA economic model). We have set a merit order for zero marginal cost generation that aligns with the assumed subsidy level for each technology type. For example, onshore wind generation will be out of merit before offshore wind generation as it is assumed that offshore wind receives greater subsidies. There is currently no distinction made between different plants within a technology type and therefore if a technology is partially out of merit then the model will reduce the output of all plants within that technology type by the same factor.

Sensitivities

2.8. Sensitivities are used to enrich the analysis for particular boundaries to ensure that relevant boundary issues are captured, such as the sensitivity of boundary capability by the connection of particular large generator. The ESO and TOs use a Joint Planning Committee subgroup as appropriate to coordinate sensitivities. This allows regional variations in generation connections and anticipated demand levels that still meet the scenario objectives to be appropriately considered.

2.9. For example, the contracted generation background on a national basis far exceeds the boundary requirements under the four main scenarios, but on a local basis, the possibility of the contracted generation occurring is credible and there is a need to ensure that we are able to meet customer requirements. A “one in, one out” rule is applied: any generation added in a region of concern is counter-balanced by the removal of a generation project of similar fuel type elsewhere to ensure that the scenario is kept whole in terms of the proportion of each generation type. This effectively creates sensitivities that still meet the underlying assumptions of the main scenarios but accounts for local sensitivities to the location of generation.

2.10. The inclusion of a local contracted scenario generally forms a high local generation case and allows the maximum regret associated with inefficient congestion costs to be assessed. In order to ensure that the maximum regret associated with inefficient financing costs and increased risk of asset stranding is assessed; a low generation scenario where no new local generation connects is also considered. This is particularly important where the breadth of scenarios considered do not include a low generation case.

2.11. Interconnectors to Europe give rise to significant swings of power flows on the network due to their size and because they can act as both a generator (when importing energy into GB) and demand (when exporting energy out of GB). For example, when interconnectors in the South East are exporting to mainland Europe, this changes the loading on the transmission circuits in and around London and hence creates different boundary capabilities.

2.12. The ESO models interconnector power flows from economic simulation using a market model of forecast energy prices for GB and European markets. The interconnector market model was improved for 2016 and now covers full-year European market operation. The results of the market model are then used to inform which sensitivities are required for boundary capability modelling. Sensitivities may be eliminated for unlikely interconnector flow scenarios.

2.13. The ESO and TOs extend sensitivities studies further to test credible conditions that may cause constraints. FES data tends to produce boundary flows in one direction, such as north to south. In some circumstances, flows may be reversed. The ESO develops relevant sensitivities in consultation with stakeholders to produce boundary capabilities for these sensitivity cases.

Interconnectors

2.14. For the NOA for Interconnectors (NOA IC), the ESO undertakes analysis to assess and provide a view on the optimum level of interconnection to other European markets. The markets considered are Belgium, Denmark, France, Germany, Ireland (the combined market of Northern Ireland and the Republic of Ireland), The Netherlands, Norway and Spain. The NOA IC process will use the output from the 2019/20 NOA as the baseline network reinforcement assumptions. The proposed NOA IC approach for 2019/20 is presented in the NOA IC methodology which can be found in Section 3 of this document.

2.15. The main benefits of the potential further interconnection analysed will be consumer, producer and interconnector welfare benefit for GB and Europe, while costs captured will include locational impacts on the GB transmission system and capital expenditure of interconnectors and associated network reinforcements. The ESO anticipates the market will respond to this intelligence with potential projects aligned with the optimum level of interconnection recommended by the ESO.

2.16. The output from the NOA IC process will be presented as a chapter in the NOA report and hence be published in late January 2020.

Offshore Wider Works (OWW)

2.17. The ESO has written the NOA report methodology so that it treats all options for system reinforcement fairly. These options can include OWW and alternative options.

2.18. The licence condition gives the ESO the duty to devise and develop OWW. The ESO has written a methodology to explain how it develops OWW up to the point that it can use the options in its economic analysis. It has been published for consultation in April 2017. This methodology is the ESO Process for OWW and covers both Developer Associated and Non Developer Associated works and can be found in Section 5 of this document.

Latest version of National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS)

2.19. The existing version of the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) is used for each annual update. If amendments are active, the potential impacts of these amendments are also considered as part of this process.

Identify future transmission boundary capability requirements

National generation and demand scenarios

2.20. For every boundary, the future capability required under each scenario and sensitivity is calculated by the application of the NETS SQSS. The network at peak system demand is used to outline the minimum required transmission capability for both the Security and Economy criteria set out in the NETS SQSS.

2.21. The Security criterion is intended to ensure that demand can be supplied securely, without reliance on intermittent generators or imports from interconnectors in accordance with NETS SQSS section C.3.2. The level of contribution from the remaining generators is established in accordance with the NETS SQSS for assessing the ACS peak demand[11]. Further explanation can be found in appendices C and D of the NETS SQSS. To investigate the system against the Security criterion, the ESO and TOs identify key network contingencies (system faults) that test the system's robustness. The ESO and TOs do this by using operational experience from the current year and interpreting this in terms of network contingencies. These are not only used directly in studies but also used to identify trends or common factors and applied in the NOA report analysis to ensure that TO options do not exacerbate these operational issues. This may lead to investment recommendations.

2.22. The Economy criterion is a pseudo cost-benefit study and ensures sufficient capability is built to allow the transmission of intermittent generation to main load centres. Generation is scaled to meet the required demand level. Further details can be found in appendices E and F of the NETS SQSS.

2.23. The NETS SQSS also includes a number of other areas which have to be considered to ensure the development of an economic and efficient transmission system. Beyond the criteria above, it is necessary to:

- Ensure adequate voltage and stability margins for year-round operation.
- Ensure reasonable access to the transmission system for essential maintenance outages.

2.24. The ESO uses the scenarios and the criteria stated in the NETS SQSS to produce the future transmission capability requirements by using an in-house tool called 'Peak Y'. The ESO then passes these capability requirements to the TOs to identify future transmission options which are described in the following section.

2.25. The ESO is investigating the use of probabilistic tools to enhance the year-round assessment by incorporating background conditions which ought to reasonably rise in the course of the year. These conditions include demand cycles, typical power station operating regimes and typical planned outage patterns. They can assist to deliver year-round network analysis on system requirements, and further ensure that all sensitivities are covered. During our validation and/or shadowing of the NOA technical studies, we intend to use the probabilistic tool and techniques to assess the credibility of the background assumptions used and discuss where network capabilities are materially different when year-round conditions are considered. Experience gained from this year's work will be used to develop the tool for use in future NOA processes.

Identify NOA options

2.26. At this stage, all the high level transmission options which may provide additional capability across a system boundary requiring reinforcement are identified (against economic and security criteria), including a review of any options considered in previous years. The NOA options are based around choices for example:

- an onshore route of conventional AC overhead line (OHL) or cable
- an onshore route of (High Voltage Direct Current) HVDC
- OWW options, such as integration between offshore generation stations.

[11] Average Cold Spell Peak Demand is defined as unrestricted transmission peak demand including losses, excluding station demand and exports. No pumping demand at pumped storage stations is assumed to occur at peak times. Please note that other related documents may have different definitions of peak demand, e.g. National Grid's 'Winter Outlook Report' quotes restricted demands and 'Future Energy Scenarios' quotes GB peak demand (end-users) demands.

2.27. Variations on each of these choices may be presented where there are significant differences in options, for instance between different OHL routes where they could provide very different risks and costs.

2.28. In response to the data on boundary capabilities and requirements, TOs identify and develop multiple credible options that deliver the potentially required boundary capabilities. The ESO produces and circulates the SRF Part A to the TOs. In response to Part A, TOs provide high level details of credible reinforcement options that are expected to satisfy the requirement. These options could be subsea links as well as onshore. Appendix D of this document provides detailed information about the SRF template. The SRF is split into six parts with a guideline on when the TO is required to complete and return each part.

Table 2. 1 Description of the parts of the SRF template and when the TOs return them

SRF Part	Description	When TOs SRF part is returned
A	Boundary requirement and capability	Mid-August (draft) Mid-September (final)
B	TO proposed options	Mid-August (draft) Mid-September (final)
C	Outages requirements	Mid-August (draft) Mid-September (final)
D	Studied option combinations and their impacts on the network	Mid-September
E	Options' costs	Mid-September
F	Publication information	Late October

The ESO has the opportunity to suggest concepts to the TOs for options to achieve the boundary requirements.

2.29. The ESO considers options for Non Developer Associated Offshore Wider Works (NDAOWW) which would deliver offshore reinforcements capable of providing the desired improvement in a boundary capability. The ESO continues with the early development of NDAOWW in accordance with Standard Licence Condition C27 Part D. This is to provide high level initial inputs to the cost-benefit analysis. To achieve this, the ESO forms a view on the technical outline and estimates the capital costs of the NDAOWW. As it is an initial and desk top exercise the capital cost estimates are likely to change significantly as the option starts to mature with further evaluation. The ESO liaises with the relevant TOs in the development of NDAOWW options.

2.30. The options that the TOs provide are listed and described in the NOA report along with ESO alternative options such as operational options. The ESO alternative options might include liaison with TOs, distribution licensees or third parties. Each option's description includes the boundary that the option relieves, categorising the option into 'build', 'reduced-build' or 'operational' and a technical outline. The option description includes any associated aspects such as the nature of the area affected, related network changes etc. The ESO is undertaking pathfinding projects in 2019/20 to trial analysis of additional system needs and to include options from non-TO sources. Where relevant the ESO will include any applicable options in the 2019/20 economic analysis.

2.31. It is recognised that as options develop, their level of detail increases. Options at a very early development stage might lack detail due to uncertainty in detailed project design such as land and consents requirements.

2.32. All TOs return the draft SRF Parts A and B in mid-August and the final version in mid-September. The timing is to support the ESO's verification studies and cost checking process. All TOs provide draft Part C in mid-August and final Parts C to E in mid-September. These form the key inputs to the cost-benefit analysis process. Part F is the means for the TOs to advise the ESO of the descriptions of the options to be published in the NOA report. The exact date is agreed between the ESO and the TOs for the year's programme for the ETYS and NOA.

2.33. Where an option affects an adjacent TO, the TOs and ESO coordinate their views on the reinforcement options and produce an agreed set of options by Week 32. The ESO uses the agreed set of options in its economic analysis and might use the options in its verification studies. If there is no agreement, the ESO forms a view on which options it assesses.

2.34. Once the TOs have returned the SRF Part A to E the ESO reviews the data and understands the costs by discussing them with the TOs. Through engagement, the ESO presents the data that it plans to use in the economic studies.

2.35. The ESO and TOs agree the combinations of options that the ESO will use in the cost-benefit analysis.

2.36. A non-exhaustive list of potential transmission solutions is presented in Table 2. 2. A wide range of options is encouraged including, where relevant, any innovative solutions.

Table 2. 2 Potential transmission solutions

Category		NOA option	Nature of constraint: Thermal	Voltage	Stability	Fault Levels
Alternative Options	Operational Options	Availability contract *(contract to make generation available, capped, more flexible and so on to suit constraint management)*	✓	✓	✓	
		Reactive demand reduction *(this could ease voltage constraints)*		✓		
		Enhanced generator reactive range through reactive markets *(generators contracted to provide reactive capability beyond the range obliged under the codes)*		✓	✓	
		Demand side services (contracted for certain boundary transfers and faults). *These allow peak profiling which can be used to ease boundary flows*	✓	✓		
		Intertrip *(normally to trip generation for selected events but could be used for demand side services)*	✓	✓	✓	
		Generation advanced control systems *(such as faster exciters which improves transient stability)*		✓	✓	
	Reduced-build Options	Co-ordinated Quadrature Booster (QB) Schemes *(automatic schemes to optimise existing QBs)*	✓	✓		
		Automatic switching schemes for alternative running arrangements *(automatic schemes that open or close selected circuit breakers to reconfigure substations on a planned basis for recognised faults)*	✓	✓	✓	✓
		Dynamic ratings *(circuits monitored automatically for their thermal and hence rating capability)*	✓			
		Addition to existing assets of fast switching equipment for reactive compensation *(a scheme that switches in/out compensation in response to voltage levels which are likely to change post-fault)*		✓	✓	
		Protection changes *(faster protection can help stability limits while thermal capabilities might be raised by replacing protection apparatus such as current transformers (CTs))*	✓		✓	
		HVDC de-load Scheme *(reduces the transfer of an HVDC Intralink either automatically following trips or as per control room instruction)*	✓	✓	✓	
		'Hot-wiring' overhead lines *(re-tensioning OHLs so that they sag less, insulator adjustment and ground works to allow greater loading which in effect increases their ratings)*	✓			
		Storage *(contracted for certain boundary transfers and faults to allow peak profiling or could exploit shorter term circuit ratings or provide voltage support to relieve constraints in operational timescales)*	✓	✓		
Build Options		Overhead line re-conductoring or cable replacement *(replacing the conductors on existing routes with ones with a higher rating)*	✓			

Category	NOA option	Nature of constraint			
		Thermal	Voltage	Stability	Fault Levels
	Reactive compensation in shunt or series arrangements (MSC, SVC, reactors). *Shunt compensation improves voltage performance and relieves that type of constraint. Series compensation lowers series impedance which improves stability and reduces voltage drop.*		✓	✓	
	Switchgear replacement *(to improve thermal capability or fault level rating which in turn provides more flexibility in system operation and configuration. This would be used to optimise flows and hence boundary transfer capability).*	✓			✓
	OHL reconfiguration *(turn-in works at substations)*	✓	✓	✓	
	Uprating of circuits *(for higher voltage levels)*	✓	✓	✓	
	Power flow control devices *(a type of Flexible AC Transmission System device that can be used to alter power flows over a circuit)*	✓	✓	✓	
	New build (HVAC/HVDC) – *new plant on existing or new routes.*	✓	✓	✓	✓

2.37. It is intended that the range of options identified has some breadth and includes both small-scale reinforcements with short lead-times as well as larger-scale alternative reinforcements which are likely to have longer lead-times. The ESO applies a sense check in conjunction with the TOs and builds an understanding of the options and their practicalities. In this way, the ESO narrows down the options whilst allowing assessment of the most beneficial solution for consumers. Other than the application of economic tools and techniques, to refine a shortlist of options or identify a potential recommended option, the ESO relies on the TO for deliverability, planning and environmental factors. The ESO leads on operability and offshore integration matters ahead of the cost-benefit analysis.

2.38. In checking for the suitability of an option, the ESO reviews options for their operability and their effect on the wider system. As a result, the ESO checks for system access, ease of operation and the ability to adhere to operational policy and national standards. For system access, this means delivery of the option and the ability to manage outages to deliver future capital works and maintenance activities. In and affecting their areas, the TOs undertake part of this review of options in conjunction with the ESO. Because of their scale and complexity, some options may need more in-depth study work and involve an iterative approach with increasing detail added between NOA reports.

Basis for the cost estimate provided for each option

2.39. The forecast cost is a central best view. By Week 30, the TOs and ESO agree each year the cost basis to be used for NOA analysis. The information that will have to be agreed includes but is not limited to:

- price base, that is the financial year of the prices and should be current year prices.
- annual expenditure profile reflecting the options' earliest in service dates.
- any major risks for options costed appropriately.
- delay costs.

- the TO's Weighted Average Cost of Capital (WACC).

2.40. The TOs provide the individual elements of the investments that provide incremental capability.

2.41. For consistency of assessment across all options, the TOs provide all relevant cost information in the current price base.

Environmental impacts and risks of options

2.42. Using the SRF the TOs provide views on the environmental impact of the options that they have proposed. This includes consideration of the environmental effects on the practicality of implementing each option.

2.43. As the TOs design and develop their options, their understanding of the environmental impacts of options improves. The more mature an option, its impact on the environment is better understood. Where appropriate, the TO indicates options that are relatively immature, which helps to highlight where the environmental impact needs further development. The ESO gives a similar indication on options that it is leading, such as OWW. As the NOA is the first step in an economic analysis of the need for reinforcement of the national electricity transmission system, it is not intended to provide an environmental assessment of those options. The TO will take any appropriate and timely environmental considerations into account as part of their investment process and according to relevant planning laws.

2.44. Different planning legislation and frameworks apply in Scotland from those in England and Wales. Where reinforcements cross more than one planning framework, this is highlighted in the NOA report together with any implications. The TOs hold the specialist knowledge for planning and consents and provide the commentary.

Checks of the costs that the TOs submit

2.45. The ESO reviews the costs that the TOs submit with their options and checks that they are reasonable. This is to help ensure the highest quality data goes into the NOA report process. The TOs use SRF Part E template to submit the costs which are also used to assess eligibility for competition. Consenting costs are submitted through the same template but are made distinct from the construction costs.

2.46. The ESO checks the costs that the TOs submit against a range of costs for plant and equipment that the ESO has gained from recent experience. If any costs are outside of the range, the ESO discusses the costs with the TO. If following discussions the ESO still believes that the costs are outside of the expected range and will unduly affect the economic analysis, the ESO can omit the option from the economic analysis.

2.47. The ESO performed the costs check for the first time as part of the 2017/18 NOA report. The process the ESO uses for the costs check is described by appendix E. This process takes into account experience gained with previous checks.

Build GB model

2.48. The TOs submit power system models to the ESO for each year being modelled. The ESO uses these along with FES data to produce complete power system models of the GB network and shares these for analysis. Additional models and modelling information for different scenarios and network options are also submitted such that the ESO and TOs have adequate information to carry out the necessary option analysis.

Boundary capability assessment for options

2.49. The ESO and TOs complete boundary capability assessment studies to feed into the cost-benefit analysis process. The TOs submit the results of their boundary studies for their own areas with their SRFs. TOs study neighbouring areas to ensure TO coordination between base capabilities and options' uplifts for those that cross TO areas. The ESO also performs studies of some of the same boundaries as the TO for the purpose of verification. For studies prior to the new SRF submission, the ESO studies reinforcements using information that the TO submitted the previous year. This assumes that many reinforcement proposals are the same or very similar from one year to the next. The TO will endeavour to provide any updates to the ESO on adjustments they make to their options that will allow the ESO to modify its studies. The ESO performs studies concurrently with the TOs to be able to perform a cross-check of some of the capability results, to the extent that the information on the options and any adjustments is available before the start of the economic analysis process. The ESO can ask the TOs for additional SRFs in the period June to August if it finds that its studies highlight a need for further reinforcement.

2.50. Thermal loading, voltage and stability boundary limitations are assessed to find the maximum boundary power transfer capability. The boundary capability is the greatest power transfer that can be achieved without breaching any NETS SQSS limitation. Variations in background to represent different network conditions, such as generation patterns or time of the year that may cause critical variations in boundary capability are assessed separately from the traditional winter peak studies.

2.51. In order to minimise unnecessary repetition whilst maintaining robustness, winter peak network analysis is carried out under the scenario that will stress the transmission system the most (in 2019 this will be the Two Degrees scenario). This scenario has the highest electrical load and generation and therefore gives us the required stress on the system to test our boundary capabilities. Where there are significant differences in network conditions, either between scenarios or in time, additional sensitivity analysis is undertaken where appropriate to understand any network capability impact. For the purposes of any stability analysis (where required), year-round demand conditions are considered. The secured events that are considered for these assessments are N-1-1, N-1 and N-D as appropriate in accordance with the NETS SQSS.

2.52. The analysis is done in accordance with the NOA study matrix which describes the constraint type, scenario, season and the years for the network assessment. Selected ‘spot’ years (7 and 10) are used as adjacent years would be too similar. The detailed NOA study matrix is populated in Appendix A of this document.

2.53. For the purpose of the boundary capability assessment, the baseline boundary conditions need to be altered to identify the maximum capability across the boundary. To make these changes, the generation and demand on either side of the boundary is scaled until the network cannot operate within the defined limits. The steady state flows across each of the boundary circuits prior to the secured event are summed to determine the maximum boundary capability.

2.54. The factors shown in Table 2. 3 below are identified for each transmission solution to provide a basis on which to perform cost-benefit analysis at the next stage.

Table 2. 3 Transmission solution factors

Factor	Definition		
Output(s)	The calculated impact of the transmission solution on the boundary capabilities of all boundaries, the impact on network security		
Lead-time	An assessment of the time required developing and delivering each transmission solution; this comprises an initial consideration of planning and deliverability issues, including dependencies on other projects. An assessment of the opportunity to advance and the risks of delay is incorporated.		
Cost	The forecast total cost for delivering the project, split to reflect the pre-construction and construction phases.		
Stage	The progress of the transmission solution through the development and delivery process. The stages are as follows:		
	Project not started		
	Pre-construction	*Scoping*	Identification of broad Needs Case and consideration of number of design and reinforcement options to solve boundary constraint issues.
		Optioneering and consenting started	The Needs Case is firm; a number of design options provided for public consultation so that a preferred design solution can be identified.
		Design/ development and consenting	Designing the preferred solution into greater levels of detail and preparing for the planning process including stakeholder engagement.
		Planning / consenting	Continuing with public consultation and adjusting the design as required all the way through the planning application process.
		Consents approved	Consents obtained but construction has not started
	Construction		Planning consent has been granted and the solution is under construction.

2.55. In order to assess the lead-time risk described in Table 2. 3, the ESO will consider, for a project with significant consents and deliverability risks, both 'best view' and 'worst case' lead-times submitted by the TOs to establish the least regret for each likely project lead-time.

2.56. It is possible that alternative options are identified during each year and that the next iteration of the NOA process will need to consider these new developments alongside any updates to known transmission options, the scenarios or commercial assumptions.

2.57. If the TOs decide that there are insufficient options to cover all scenarios, they initiate further work to identify reinforcement options. The TOs aim for at least three options for each boundary requirement. The TOs can submit long-term conceptual options to ensure that there are enough options. The long-term conceptual options are high level and are developed only as far as their boundary transfer benefits and initial estimate of costs. Power system analysis is not conducted on the conceptual options.

2.58. Where there are boundaries affecting more than one TO, the TOs should arrange challenge and review meetings to determine the options for inclusion in the economic analysis and in the NOA report.

2.59. The TOs use their boundary capability results in the SRF Part D that they submit back to the ESO.

2.60. The ESO leads on operational options in cooperation with the TOs. The economic analysis tool needs a MW value for the boundary capability which this analysis of operational options must provide. In addition, the ESO must provide ongoing costs for the economic analysis such as intertrip arming fees as well as any capital outlay such as the cost of designing/installing the intertrip.

Cost-benefit analysis

Introduction

2.61. Cost-benefit analysis compares forecast capital costs and monetised benefits over the project's life to inform this investment recommendation.

2.62. The NOA provides investment recommendations based on the Single Year Regret Decision Making process. If the ESO's NOA recommendation is to proceed and triggers an SWW Needs Case, the ESO will assist the TO to produce an SWW Needs Case by undertaking a more detailed cost-benefit analysis.

2.63. The purpose of the Single Year Regret Decision Making process is to inform investment recommendations regarding wider transmission works for the coming year. The main output of the process is a list of recommended wider works reinforcement options to proceed with or to delay in the next year. A secondary output is an indicative list of which options would be proposed at present if each of the scenarios were to turn out.

2.64. The methodology for SWW cost-benefit analysis follows the **Guidance on the Strategic Wider Works arrangements in the electricity transmission price control, RIIO-T1** document published by Ofgem[12]. A Needs Case is submitted by the TO that proposes the option to the regulator, and which includes a cost-benefit analysis section that outlines the financial case for the option. The output of this process is a recommendation of an option for the option that is to be proceeded with.

Cost-benefit analysis methodology

2.65. Since the number of options proposed for the transmission system is quite large the country is split into regions and each option is allocated to one of the regions. The cost-benefit analysis process for each region is conducted in isolation. The year in which each of the options outside the region that is being studied will be commissioned is fixed to a pre-determined value, which may vary by scenario. This is usually based upon the recommendations of the

[12] https://www.ofgem.gov.uk/ofgem-publications/83945/guidanceonthestategicwiderworksarrangementsinriiot1.pdf

most recent NOA report. The size and extent of a region (that is where region dividing lines are drawn) may change from year to year. The criterion by which a region is defined is that an option may not appear in more than one region (this is to prevent an option being evaluated more than once, with the risk of two different answers).

2.66. All of the four scenarios are considered; furthermore, it is usual for sensitivities to be considered as described previously. Each scenario is studied in isolation; the following description refers to the study of one scenario, the process is repeated (in parallel since there is no dependency) for the other scenarios. The process is an iterative process that involves adding a single reinforcement at a time and then evaluating the effect that this change has had on the constraint cost forecast.

2.67. To begin the process all proposed options within the region are disabled, the output of the model is analysed to determine which boundaries within the region require reinforcement and when the option is required, this simulation is referred to as the base case. This information is used to determine which option(s) should be evaluated first. The option that has been selected to be evaluated next is then activated in the constraint cost modelling tool (see Table 2.4 for a description) at its EISD. If a number of potential options have been identified as being candidates for the next option then this process must be repeated with each option in turn. There are now two sets of constraint cost forecasts, the base case and the reinforced case, which are compared using the Spackman[13] methodology.

2.68. It is assumed that each transmission asset is to have a 40-year asset life. Since the constraint cost modelling tool only forecasts for the next 20 years the constraint costs for each year after that are assumed to be identical to the final simulated year (note that this limitation occurs because the scenarios do not contain detailed ranking orders beyond 20 years). Constraint cost forecasts are discounted using HM Treasury's Social Time Preferential Rate (STPR) to convert the forecasts into present values. The capital cost for the option is amortised over the asset life using the prevalent WACC and discounted using the STPR. This value is added to the constraint cost forecast for the reinforced case. The present value of the base case is then compared to the present value of the reinforced case plus the amortised present value of the capital costs to give the net present value (NPV) for this option.

2.69. This cost-benefit analysis process is carried out in a separate comparison tool which also automatically calculates the NPVs if the option being evaluated were to be delayed by a number of years. This list of NPVs allows the optimum year for the option, for the current scenario, to be calculated. If a number of alternative candidate options have been identified, then the option that has the earliest optimum year should usually be chosen. The chosen option is then added to the base case and another option is chosen for evaluation. The process is then repeated until further options produce a negative NPV (which would indicate that the capital cost of the option exceeds the saving in constraint costs). There may be an element of branching if it is not immediately obvious during the process which option should be chosen to be added to the base case at any given point.

2.70. The outcome of this process is a list of options, for the current region and scenario, and the optimum year for each. This is referred to as a 'reinforcement profile'.

[13] The Joint Regulators Group on behalf of UK's economic and competition regulators recommend a discounting approach that discounts all costs (including financing costs as calculated based on a Weighted Average Cost of Capital or WACC) and benefits at HM Treasury's Social Time Preference Rate (STPR). This is known as the Spackman approach.

2.71. Once the reinforcement profile for each scenario within a region has been determined the 'critical' options for that region may be chosen. The definition of a 'critical' option has some flexibility but the definition below must be considered.

2.72. An option's recommendation is critical if a decision to delay the option in the current year means that the optimum year, under any scenario or sensitivity, could no longer be met (note that outage availability may play a part in this decision).

Constraint cost modelling tool

2.73. The constraint cost modelling tool is used to forecast the constraint costs for different network states and scenarios. The high-level assumptions and inputs used in the tool are outlined in Table 2. 4.

Table 2. 4 Assumptions and input data for the constraint cost modelling tool

Input Data	Current Source	Description
Fuel price forecasts	FES	20-year forecast, varies by scenario
Carbon price	FES	20-year forecast
Plant efficiencies and season availabilities	Poyry (historic)	
Plant bid and offer costs	Historic data	See Long-term Market and Network Constraint Modelling[14]
Renewable generation	Poyry (historic)	Wind, solar, and tidal profiles for zones around the UK
Demand data	FES	Annual peak and zonal demand
Demand profile	Poyry	Within year profiles
Maintenance outage patterns	Historic data	Maintenance outage durations by boundary
System boundary capabilities	Power system studies	See text
Reinforcement incremental capabilities	Power system studies	See text

2.74. The model is set to simulate 8 periods per day for 365 days per year and is set to simulate 20 years into the future. The year in which an option is commissioned can be varied. The primary output from the tool for the cost-benefit analysis process is the annual constraint forecast; there are further outputs that help the user identify which parts of the network require reinforcement.

[14] See https://www.nationalgrideso.com/insights/network-options-assessment-noa

Selection of recommended option

2.75. At this point, all of the economic information available to assess the options is in place. The ESO then uses the Single Year Least Regret analysis methodology to identify the recommended option or combination of recommended options.

Single year least regret decision making

2.76. The single year least regret methodology involves evaluating every permutation of the critical options in the first year (the year beginning in April following publication of the NOA report). For each critical option, there are two choices, either to proceed with the option for the next year or to delay the option by one year (that is do nothing). It is assumed that information will be revealed such that the optimal steps for a given scenario can be taken from year two onwards – so only the impact of decisions in the first year are evaluated. If there is more than one critical option in the region then the permutations of options increase; the number of permutations is equal to 2^n, where n is the number of critical options.

2.77. Each of the permutations has a series of cost implications, these are either additional capital and constraint costs if the option were delayed (and further additional costs if the option were to be restarted at a later date) or inefficient financing costs if the project is proceeded with too early.

2.78. For each permutation and scenario combination the present value is calculated, taking into account operational and capital costs. For each scenario one of the permutations will have the lowest present value cost, this is set as a reference point against which all the other permutations for that scenario are compared. The regret cost is calculated as the difference between the present value of the permutation for a scenario and the present value that is lowest of all permutations for the scenario. This results in one permutation having a zero regret cost for each scenario.

2.79. The following section is a worked example of the least regret decision making process. Two options have been determined to be 'critical' in this region, the EISD for option 1 is 2020 and the EISD for option 2 is 2021. The optimum years for scenarios A, B and C are shown in Table 2. 5. Note that the scenarios are colour-coded; this is used for clarity in the following tables.

Table 2. 5 Example of optimum years for two critical reinforcements

Scenario	Option 1	Option 2
A	2020	2021
B	2020	2024
C	2027	N/A

Table 2. 6 Example decision tree

Permutation	Year 1 Recommendations	Completion Date	NPV	Regrets	Worst regret for each permutation
i	Proceed Option 1 & Delay Option 2	Option 1: 2020 Option 2: 2021	£149m	£51m	£51m
		Option 1: 2020 Option 2: 2024	£100m	£0m	
		Option 1: 2027 Option 2: Cancel	£145m	£5m	
ii	Delay Option 1 & Proceed Option 2	Option 1: 2021 Option 2: 2021	£98m	£102m	£102m
		Option 1: 2021 Option 2: 2024	£65m	£35m	
		Option 1: 2027 Option 2: Cancel	£140m	£10m	
iii	Proceed Option 1 & Proceed Option 2	Option 1: 2020 Option 2: 2021	£200m	£0m	£15m
		Option 1: 2020 Option 2: 2024	£98m	£2m	
		Option 1: 2027 Option 2: Cancel	£135m	£15m	
iv	Delay Option 1 & Delay Option 2	Option 1: 2021 Option 2: 2022	£47m	£153m	£153m
		Option 1: 2021 Option 2: 2024	£68m	£32m	
		Option 1: 2027 Option 2: Cancel	£150m	£0m	

2.80. Table 2. 6 is an example of a least regret decision tree, since there are two ‘critical’ options there are therefore four permutations. From Year 2 onwards for each of the permutations the options are commissioned in as close to the optimum year for each option for each scenario. For each scenario one of the four permutations is the optimum and therefore there is one £0m value of regret for each scenario. The table’s NPV column indicates the net present value for each of the permutations in each of the scenarios.

2.81. Studying Table 2. 6 shows us that it is largely scenarios A and C that are deciding the single year least worst regret. There is a large regret in scenario A from choosing any other permutation than permutation 3 (at least £51m), and scenario C is the scenario that generates the maximum regret for permutation 3. If we calculate the implied probabilities for the decision to proceed with permutation 3 rather than 1 or 4 we find that the implied probabilities are roughly 16% and 9% for A vs. C respectively. This shows us that in order to make the same decision under expected NPV maximisation we would need to believe that A is at least 16% likely and C is less than 84% likely to choose 3 over 1, and A is at least 9% likely and C is less than 91% likely to choose 3 over 4. As an example, 16% implied probability for scenario A vs. C when considering 3 vs. 1 was found by solving the following equation:

$$200p + 135(1-p) > 149p + 145(1-p)$$

where p is the probability of scenario A and (1-p) is the probability of scenario C. It is worth noting that implied probabilities must be kept to two scenario comparisons for a single choice (i.e. 3 vs. 1) since expanding the scenario and permutation space would make the implied probabilities intractable to interpret.

2.82. The causes of the regret costs vary depending upon what the optimum year is for the reinforcement and scenario:

- If the option is delayed and therefore cannot meet the optimum year, then additional constraint costs will be incurred.
- If the option is delayed unnecessarily then there will be additional delay costs.
- If the option is proceeded with too early, then there will be inefficient financing costs.
- If the option is proceeded with and is not needed, then the investment will have been wasted.

2.83. The regret costs for each permutation under all scenarios are then compared to find the greatest regret cost for each permutation. This is referred to as the worst regret cost. The permutation with the least 'worst regret' cost is chosen as the recommended option or combination of options to proceed in the coming year and appears in the report's investment recommendation. In the example shown above the least 'worst regret' permutation is to proceed with both options 1 and 2 which has a worst regret of £15m and is the least of the four permutations.

2.84. As the scenarios represent an envelope of credible outcomes it is possible that a reinforcement option is justified by just one scenario which doesn't always guarantee efficient and economic network planning if industry evolution were not to follow that particular scenario. In this event, the ESO would examine the single year regret analysis result to establish the drivers and then examine the scenario further. How we do this varies according to circumstances but an example would be considering the cost-benefit analysis's sensitivity to specific inputs. This in turn informs our view on the robustness of the outcome and thus whether to make a recommendation based upon this scenario. The ESO supports all the TOs in this manner to optioneer and develop their projects to minimise the cost such as reducing any frontloading of expenditure if there is doubt about the need for the reinforcement option or downgrading the importance of the investment completely. The ESO examines any sensitivity studies in the same way to ensure none skew the results unfairly. For example, if a change in policy were to occur after the publication of the FES document, significant amounts of generation in the scenarios may be affected and their connection may then be delayed or unlikely to go ahead. We would flag this kind of background update, and identify in the single scenario driven investments where this is likely to be creating a skewed outcome. The areas of sensitivity study are outlined in Appendix A. The ESO is investigating the development of probabilistic tools to deliver year-round network analysis on thermal and voltage network requirements, and further ensure that all sensitivities are covered. However, this is at an early stage and not yet ready for use with the NOA.

Process output

2.85. Following Single Year Regret analysis, for each region in the country a list of ‘critical’ options for the region is presented with the investment recommendation for each.

2.86. The ESO has introduced implied scenario weightings to provide additional insight into the single year regret analysis. The ESO does not assign probabilities to any of its scenarios, however it is useful to know what probability weights are consistent with the recommendations. This is particularly useful for options which are driven by a single scenario. The ESO identifies the scenario where the option brings the most benefit and the scenario where the option brings the least benefit. It then calculates the weightings between these two scenarios that would be required in order to justify the recommendation for investment in this option under expected net present value maximisation. This allows the ESO to reflect upon whether the implied probability of the driving scenario is reasonable to justify next year expenditure. For more information including examples, please see our NOA Methodology Review which can be found at www.nationalgrid.com/NOA .

2.87. The ESO has created the NOA Committee to challenge the single year regret recommendations. The Committee is designed to allow the ESO to review the investment recommendations that are marginal or risk being driven by a single scenario. This will seek to identify any ‘false-positive’ investment recommendations that could come about as a result of the single year regret process, and ensure that the single year regret analysis recommendations are justified. In addition, the Committee will ensure the recommendations are supported by the holistic needs of the system. The Committee consists ESO senior management who will challenge the robustness of the investment recommendations as well as provide holistic energy industry insight and take into account whole system needs to support or revise the marginal investment recommendations. Ofgem will also be present as observers to represent the consumers’ interests and provide regulatory oversight, as well as understand the driving factors behind recommendations. In preparation for the Committee meeting, the ESO will discuss the single year regret outputs with internal stakeholders and the TOs to ensure the final recommendations are robust. The TOs are invited to attend the NOA Committee to provide supporting evidence as the committee requires while maintaining the necessary commercial confidentiality.

2.88. The guiding principle behind the NOA committee is that, on the marginal decisions the Committee reviews, the members should advise the investment recommendation they believe is most prudent, on the balance of evidence. This means that they believe, on the balance of probabilities, the recommendation (to proceed or delay) is the best course of action for the GB consumer. This will take into consideration the many facets of the decision including, but not limited to: forecasted constraints in the scenario(s) advocating the option; the drivers behind the investment recommendation (e.g. specific generation build-up) and the latest market information on those drivers; what the regret is across the other scenarios; what next year’s expenditure is acquiring and what it will achieve (e.g. will the expenditure allow the TO to learn more about the option); what effect a delay decision will have on the earliest in service date (e.g. more than one year postponement in the earliest in service date); what the implied scenario weight of the decision is (that is what probability would have to be placed on the driving scenario to make the same decision under expected net present value maximisation); and wider system operability considerations including the availability of commercial solutions to congestion issues. The committee members should seek to have a risk-neutral outlook in their deliberations, that is they should seek to make decisions dispassionately, and on the balance of evidence, bearing in mind as much as possible the likelihood of future events.

2.89. After deliberation committee members will conclude on the marginal options. The Committee’s aim is to reach a consensus. The outcomes will be minuted and these minutes will show the rationale behind the recommendations as well as highlight the challenges raised. The minutes will be made available to Ofgem and the TOs and published on the NOA webpage.

2.90. The ESO uses the output from the single year regret analysis for the recommendation on whether a reinforcement option should proceed under the England and Wales NDP framework.

2.91. If the investment signal triggers the TO's Needs Case, the ESO will assist the TO in undertaking a more detailed cost-benefit analysis. The ESO reconciles the economy and security results (in accordance with NETS SQSS Chapter 4) as mentioned previously in the section on sensitivities before making a final recommendation.

2.92. If a TO does not follow a NOA recommendation, it must inform the ESO at the earliest opportunity and tell the ESO about the effect on the option's EISD. If the TO has discretion over the change, it should fully involve the ESO in the decision process. The NOA Committee will monitor the process and the outcome.

Cost bands

2.93. The ESO sorts reinforcement options with a 'Proceed' recommendation after economic analysis and connections into cost bands which it then includes in the NOA. The assumptions are that land costs are included in the costs but the cost of consents is excluded. The costs apply for new and separable elements only. Table 2. 7 shows the cost bands that have been agreed.

Table 2. 7 Table of cost bands

Cost bands
£100m - £500m
£500m - £1000m
£1000m - £1500m
£1500m - £2000m
Greater than £2000m

Report drafting

2.94. The ESO drafts the NOA report but the responsibility for the content varies between the ESO and TOs. The form of the report is subject to consultation and also to Ofgem approval. Appendix F gives more detail on the form of the NOA report.

Chapters 4 and 5 cover the options and their analysis. The component parts of these chapters and the responsibilities for producing the material are in

2.95. Table 2. *8*. Appendix F gives more detail on the form of the NOA report.

Table 2. 8 Areas of Responsibility

NOA report Options topic	Build options	Alternative options	Offshore	Comments
Options: Status of the option (scoping, optioneering, design, planning, construction)	TO	ESO/TO	ESO	
Options: Technical aspects – assets and equipment	TO	ESO/TO	ESO	
Options: Technical aspects – boundary capabilities	TO	ESO/TO	ESO/TO	
Options: Economic appraisal	ESO	ESO	ESO	Leads to investment recommendations for TOs
Options: Comparison of the options	ESO	ESO	ESO	
Options: Competition assessment	ESO	ESO	ESO	Includes competition criteria and how options were categorised

2.96. The report presents the relevant information to communicate the investment recommendations whilst maintaining appropriate commercial confidentiality. Information is therefore presented to demonstrate the relative benefits of options while protecting commercial confidentiality. This is in consultation with stakeholders. The ESO passes outputs to the TOs to support its view of investment recommendations.

2.97. Report drafting is undertaken in the period late July to mid-December.

Report publication

2.98. The ESO publishes the NOA report by 31January of each year or as instructed otherwise by Ofgem.

2.99. On publication, the report is placed on the National Grid website in a PDF form that is widely readable by readily available software. The ESO also prints copies such that it can provide on request and free of charge a copy of the report to anyone who asks for one.

2.100. Standard Licence Condition C27 Paragraph 12 provides for delaying publication if the Authority (Ofgem) delay their approval of the NOA report methodology or form of NOA report.

2.101. The Licence Condition allows for the omission of sensitive information.

3

Network Options Assessment for Interconnectors

Overview

3.1 This chapter provides an overview of the aims of the NOA with respect to interconnectors and details the methodology which the ESO will adopt for the analysis and publication within the fifth NOA report (to be published by 31st January 2020).

3.2 We have continued to develop the NOA for Interconnector methodology. This chapter represents our latest thoughts. We received valuable feedback on the draft methodology which has resulted in further improvements to the methodology. We will continue to develop the NOA for Interconnector methodology by actively consulting, listening and responding to feedback from our customers and stakeholders. This will enable us to revise and improve the methodology, resulting in a NOA for Interconnectors analysis that continues to be of increasing value for our stakeholders.

3.3 For reference, below is a summary of the key features and developments of the previous NOA for Interconnector methodologies.

NOAIC 1 (2015/16)	**NOAIC 2 (2016/17)**	**NOAIC 3 (2017/18)**	**NOAIC 4 (2018/19)**
- Modelled through ELSI - GB consumer surplus only - Price data procured from industry - Only considered existing interconnectors and those applied through C&F - Copper plate model with no transmission constraints	- Modelled through Pan European Market Model (BID3) - SEW as sum of producer and consumer surplus as well as interconnector revenue - Consideration of benefit of additional capacity - Copper plate model with no transmission constraints	*(As per NOAIC 2 plus…)* - Use of FES 2017 backgrounds - Used optimised network found through NOA3 as baseline - Combination of interconnectors and potential reinforcement - Single optimal path generated through a least worst regret approach	(As per NOAIC 3 plus…) - Use of FES 2018 backgrounds, including European FES - Provide a range of solutions by not undertaking least worst regret - Analysis of the impact of interconnectors on system operability

Structure of this section

3.4 This section consists of the thirteen sub-sections listed below:

- **Key changes to 2019/20 methodology -** A summary of the major changes made to the NOA for Interconnector methodology for 2019/20.
- **Key similarities to the 2018/19 methodology -** A summary of which areas of the methodology have remained the same from 2018/19 to 2019/20.
- **Factors for the assessment of future interconnection -** A justification of the factors to be considered in determining whether additional capacity would be beneficial.
- **Cost estimation for interconnection capacity** – The costs associated with an interconnector and how these will be calculated.
- **Cost estimation for network reinforcement** – The costs associated with network reinforcements and how these will be calculated.
- **Components of welfare benefits of interconnection** – This sub-section outlines the concept of Socio-Economic Welfare in relation to interconnection and the components of the calculation.
- **Constraint cost implications** – An outline of how interconnectors could impact the operational costs on the network.
- **BID3 model** – A description of the ESO’s current market modelling capabilities
- **Options included within the assessment** – A listing of the options that will be assessed within the modelling.
- **Interconnection assessment methodology** – A description of the method by which the ESO proposes to meet the aims of the NOA in relation to optimal interconnection capacity.
- **Further Output** – Additional results that may be of benefit to stakeholders.
- **Process Output** – How the NOA IC output will be delivered.

Key changes for 2019/20 methodology

3.5 This year we will continue to improve the NOA for Interconnectors analysis by acting on feedback from our stakeholders.

3.6 We will refocus on providing additional value from the main iterative analysis on social economic welfare, capital costs and constraint costs, by drawing greater insights from the use of the European FES, which improve the quality and range of interconnector modelling that drives the NOA IC analysis, as well as improving the GB-specific constraint and network analysis.

3.7 We will revise the method used for setting the interconnector baseline level to ensure that the baseline level of interconnection represents a solution that cannot inadvertently be seen to be favouring specific projects.

3.8 We will use the NOA IC as a signpost to other system operability work being undertaken within the System Operability Framework, rather than attempt to undertake an analysis of the impact of interconnectors on system operability within the NOA IC analysis.

Key similarities to 2018/19 methodology

3.9 We will continue to take into consideration the locational impacts on the GB transmission network in addition to the welfare and capital cost implications, and provide greater insight to ourstakeholders of the effects of interconnection on the network.

3.10 We will continue to focus on Social Economic Welfare, capital costs and reinforcement costs.

3.11 We will use the output from the 2019/20 NOA as the baseline network reinforcement assumptions for the NOA IC analysis: this provides greater consistency between the NOA and NOA IC analysis which we believe is of added value to our stakeholders.

3.12 We intend to use essentially the same iterative method used last year. The studies will involve a step-by-step process, where the market is modelled with a base level of interconnection, including current interconnection levels and projects with regulatory certainty. Four separate solutions will be created and hence a range for the optimal level of interconnection, as in NOA IC 2018/19, which stakeholders felt was more realistic and useful.

3.13 We will continue to calculate Social Economic Welfare for all EU countries as well as for GB and the connecting country. We will investigate whether there is any benefit in calculating the optimal path based on the Social Economic Welfare of GB and the connecting country only.

3.14 We will continue to highlight the impact of interconnection on carbon costs and renewable energy curtailment. Greater focus and value.

3.15 We will provide a similar level of detail to that provided in NOA IC 2018/19, but continue to provide greater insight and explanation into what is driving the results and also improve graphical representation of results. Transparency

3.16 We will continue to develop NOA IC based on stakeholder recommendations.

Factors for the assessment of future interconnection

3.17 There are multiple factors which could be considered when evaluating interconnector projects. The foremost are social economic welfare, capital costs and impact on constraint costs. Constraint costs refer to GB network congestion costs borne by GB consumers as a result of interconnection.

3.18 SEW, CAPEX and Attributable Constraint Costs (ACC) are the most significant criteria for identifying the optimal level of interconnection. Therefore, these factors will be used in the analysis to determine the economically optimal level of interconnection.

3.19 Two further factors that will be analysed and have some accompanying commentary in the NOA report are changes in carbon emissions and use of Renewable Energy Sources (RES). These indicators are intended to aid understanding of interconnection's potential impact to meeting GB's climate change goals. They will not be used to optimise the interconnection presented. This is due to the complexity of combining Carbon/RES estimates with welfare and cost, especially where modelled welfare is already influenced by such factors through RES incentives and the European Trading System capping carbon emissions.

3.20 **Carbon costs**: modelling facilities allow for the extraction of total carbon emissions resulting from particular market states under different scenarios, thus the carbon savings or increases associated with various levels of interconnection can be presented with commentary.

3.21 **RES integration:** modelling facilities allow for the investigation of impact of interconnection on renewable generation. This can be reviewed through investigating the reduction or increase in renewable generation curtailment driven by the optimal level of interconnection being in place in future years, rather than the currently forecast level.

3.22 Last year, due to the inclusion of the ancillary services analysis, we provided less analysis of carbon costs and RES integration. This year, our stakeholders have stated that they would prefer a renewed focus on environmental factors, with an expanded output on the impact of increased interconnection on carbon costs and RES curtailment, as the debate on what path GB will pursue to transition to a low carbon future continues to increase.

Factors outside the methodology scope

3.23 There are further benefits and costs that could be considered, which are briefly outlined below; they are outside the scope of this methodology:

3.24 **Operational costs:** Various costs associated with the day-to-day operation of the interconnector, and the maintenance of its components, are omitted from the analysis. This is driven by the complexity of defining these costs, per market. There is a high correlation between capital spend (which is included) and these operational costs. Moreover, there is unlikely to be a substantial variation in the ‘standard’ operational costs per European market under consideration, meaning it is equitable to remove them from consideration for all markets. One may argue that the operational costs may cause the end of the optimal path to be reached sooner however a decision has been made to omit this factor from the analysis due to the insignificance in relation to SEW over 25 years.

3.25 **Environmental/social costs:** In any large scale construction project, the local environment may potentially suffer damage. This affects local stakeholders, as well as disruption associated with the construction (traffic, noise etc.). The severity varies with the site chosen and the construction methods used. These are not considered here as they are more relevant to the choice of sites for individual projects.

3.26 **Social benefits:** Depending upon the procurement for the construction, the project may offer a boom to the local economy. This again is a project specific benefit, so is not estimated in this work.

3.27 **Ancillary Service costs:** We will not attempt to model the potential impact of interconnectors on services which support system operability. Initial feedback on the system operability analysis undertaken for NOA IC 2018/19 was mixed. The results were complex and difficult to draw high level conclusions from. Some stakeholders felt the analysis placed an inappropriate focus on the benefit or disbenefit of interconnectors on system operability, and that a wider lens would be more appropriate. There were also concerns with the robustness of analysis so far into the future.

3.28 A more detailed analysis of system operability as part of NOA for Interconnectors does not fit well with the high-level market signal approach of other NOA for Interconnectors market analysis work. In addition, the time available for the NOA for interconnectors modelling, which can only commence after the NOA reinforcement recommendations are available and must be complete before the end of January, makes this infeasible.

3.29 We believe a more appropriate solution is to undertake this type of analysis as part of the System Operability Framework which takes a holistic view of the changing energy landscape to assess the future operation of Britain's electricity networks. Interconnectors may be one of a range of potential service providers or may be one of a range of assets that may result in system operability issues. The NOA for Interconnectors analysis can be used as a means of highlighting this work.

Cost estimation for interconnection capacity

3.30 The cost of building interconnection capacity varies significantly between different projects - key drivers are convertor technology, cable length and capacity of cable. Estimating costs for generic interconnectors between European markets and GB is therefore challenging. An exercise of a similar nature has been undertaken by various industry bodies to allow the generation of ‘Standard Costs’. These are generic values that can be applied to estimate the cost of generic projects. A report by ACER[15] provides sufficient granularity to differentiate between standard costs of connection to different markets. There are three elements to the capital costs; subsea cable, onshore connection costs and wider reinforcement costs. We will continue to review and investigate alternative robust sources for generic interconnector cost estimates.

[15] http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/UIC%20Report%20%20-%20Electricity%20infrastructure.pdf

3.31 Subsea cable costs will be identified by estimating the furthest and shortest realistic subsea cable length and taking the average distance for each market to GB zone permutation. Suitable substations have been identified using the ENTESO-E Transmission System Map. The length of the cable will vary with the GB zone it is connecting to and the measurements will be taken between these to the nearest 5km and are shown in the following table.

Table 3. 1 Route distances

Country	GB Zone	Distance (Km)
Norway	1	705
Norway	2	795
France	5	175
France	6	100
Netherlands	4	215
Netherlands	6	210
Denmark	4	620
Denmark	7	660
Ireland	2	220
Ireland	3	220
Germany	4	520
Germany	7	590
Belgium	4	185
Belgium	6	140
Spain	5	810

3.32 Onshore connection costs will be excluded as the interconnector study cases are zone specific but not substation specific.

3.33 Wider reinforcement costs will be included in capital costs for options where applicable.

3.34 The convertor station assumed value is drawn from an averaging of known HVDC projects performed by ACER. The ACER cost estimates are shown in the table below (these costs include the cost of installation):

Table 3. 2 Standard costs

Total cost per route length (km)	Rating	Mean (€, 2014)
DC cables[16]	250-500kV	757,621
OHL[17]	380-400kV (2 circuits)	1,060,919

[16] The DC cable cost provided is for a 500MW cable. An assumption has been made that for a 1000MW interconnector the cost per km will be double.

[17] The rating on the figures above is sufficient to accommodate an additional 2000MW of interconnection. Therefore, the figures will be adjusted to incur 70% of the total cost for the first 1000MW of capacity required and 30% for the second 1000MW of reinforcement capacity on the same boundary.

Underground cables[21]	380-400kV (2 circuits)	4,905,681

Total cost per rating (MVA)	Mean (€, 2014)
HVDC convertor station	87,173

3.35 At the start of the analysis, the suitable rate of conversion from 2014 euros to present day sterling will be drawn from a credible source available to the ESO (Bloomberg). The table can then be used to generate a generic cost for a given increase in capacity for each market. As connection can occur across a range of years, discounting is employed to standardise each cost in Present Value. This is done with the Social Time Preference Rate (STPR) of 3.5%. Additionally, the cost of capital is taken account of through the use of a Weighted Average Cost of Capital (WACC) of 6.8% for interconnectors, drawn from a publicly available Grant Thornton report.[18]

Cost estimation for network reinforcements

3.36 The network has been divided into seven high level zones which have been determined by areas of significant constraints on the network or areas of high interconnection as illustrated in Figure 3. 1.

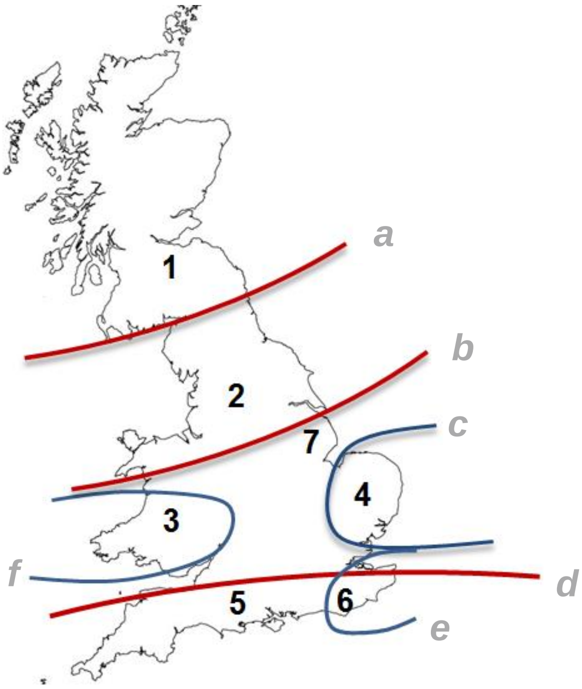


Figure 3. 1 Illustration of Network Zones

3.37 The baseline boundary capabilities will be determined by using the outputs from the main NOA 2019/20 analysis. Additional boundaries, and hence zones may be added if their addition may increase the value of the analysis.

3.38 Generic reinforcements will be created for each boundary. These will be based on where there are high levels of congestion on the network and provide an indication of the level of reinforcements required.

[18] https://www.ofgem.gov.uk/ofgem-publications/51476/grant-thornton-interest-during-construction-offshore-transmission-assets.pdf

Components of welfare benefits of Interconnectors

Introduction

3.39 This section outlines the definition of Social Economic Welfare. The purpose of this section is to give the theoretical background of assessing the impact of connected importing and exporting markets on consumers, producers and interconnectors triggered by another interconnector.

Social and Economic Welfare

3.40 Social and Economic Welfare (SEW) is a common indicator used in cost-benefit analysis of projects of public interest. It captures the overall benefit, in monetary terms, to society from a given course of action. It is important to understand it is an aggregate of different parties' benefits - so some groups within society may lose money as a result of the option taken. The society considered may be a single nation, GB, or the wider European society, in which case the benefits to European consumers and producers would be a part of the calculation. For the case of GB interconnectors, it is most informative to show both GB and the connected market's SEW values, and the components which make up each.

3.41 SEW benefits of an interconnector includes the following three components:

a) Consumer surplus, derived as an impact of market prices seen by the electricity consumers

b) Producer surplus, derived as the impact of market prices seen by the electricity producers

c) Interconnector revenue or congestion rents, derived as the impact on revenues of interconnectors between different markets.

3.42 Interconnectors could help to provide ancillary services (including black start capability, frequency response or reserve response), facilitate deployment of renewables, reduction in carbon emissions and displace network reinforcements. Interconnectors also provide benefits of being connected to more networks giving access to a more diverse range of generation which could lead to reduction in carbon emissions. Such benefits will not be a part of the main NOA IC assessment, as discussed in the previous section.

Effects on Interconnected markets

3.43 Power flow between two connected markets is driven by price differentials. Figure 3. 2 shows the effects of such price differentials for two markets, A and B with variable prices over time. When the price is higher in market A, power will be transferred from B to A. When the price in A is lower than B power will be transferred from A to B.

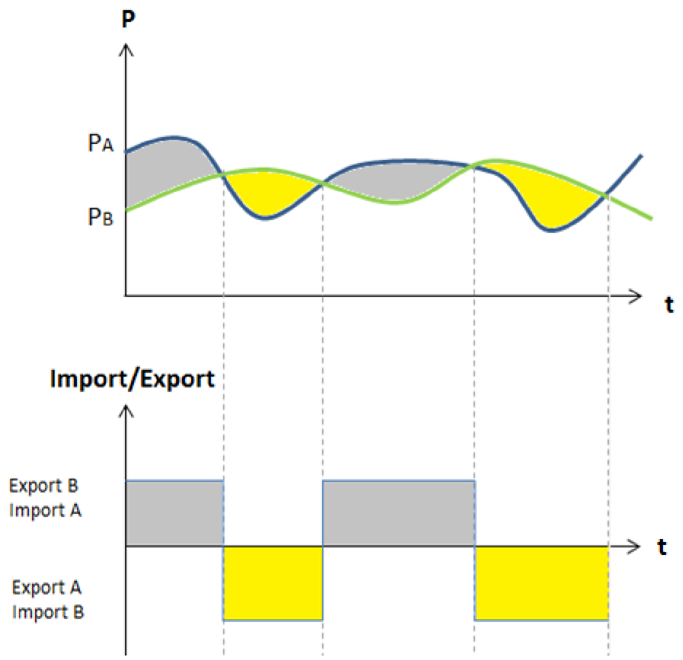


Figure 3. 2 Price difference as import and export driver

3.44 Figure 3. 3 shows the impact of an interconnector (+IC) linking two markets on consumer (Demand D) and producer (Supply S) costs. When two competitive markets with different price profiles are interconnected, price arbitrage drives power flow from the low price market (B) to the high price market (A). Consumers in market A are likely to gain (a + b) as they benefit from access to cheaper power. Consumers in market B are likely to lose (d). Generators in market A must now also compete with generators in B and are likely to be forced by competitive pressures to reduce their costs. This may lead to a reduction in their profits (a). Producers in market B are likely to gain (d + e). Interconnector revenue (c) is derived from the remaining price difference.

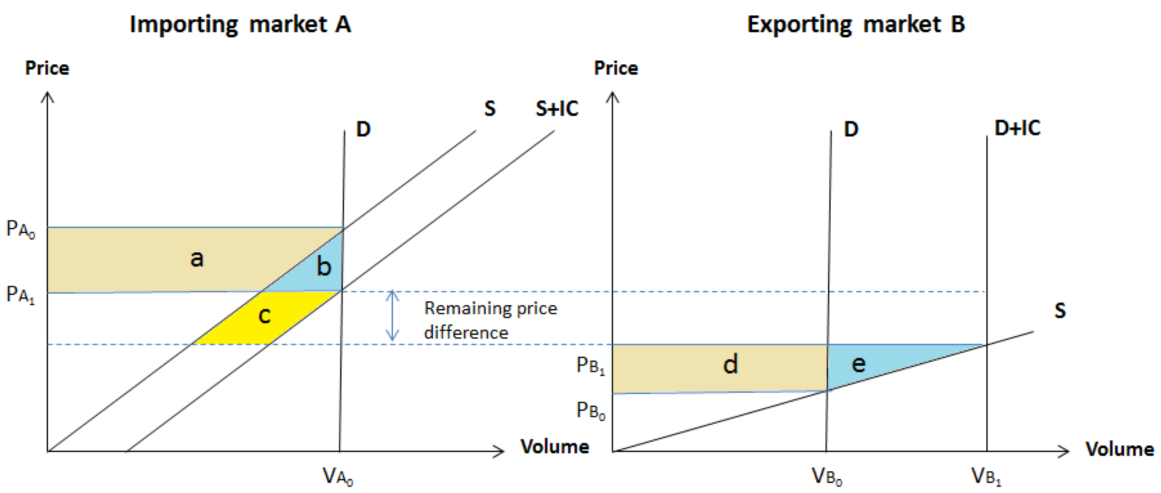


Figure 3. 3 Consumer and Producer Surplus of connected markets

3.45 With greater interconnection, the price difference between markets will decrease thus the revenue of the interconnector will be reduced as well. This phenomenon is known as 'cannibalisation'. There is an optimal level of interconnection between any two markets because price differential reduces as capacity increases, i.e. area c in Figure 3. 3 shrinks.

3.46 Forecasts of all components of SEW benefits will be key drivers to ascertain the optimum level of interconnection between GB and other European states. The outputs of this process will include monetised impacts on consumers, producers and considered interconnectors.

3.47 The Global SEW is the sum of the welfare of 5 parties (GB consumers, Europe consumers, GB producers, Europe producers and Interconnector owners). The British SEW is the sum of the welfare of all British parties. Using the ownership structure of existing GB interconnectors, assuming 50% of interconnector owner welfare remains in the GB economy is plausible.

3.48 Where the market is modelled with and without some additional interconnection capacity added, SEW is modelled in each year of a generic asset's lifetime (25 years is the standard assumption used here). As connection can occur across a range of years, discounting is employed to standardise each year's benefit in Present Value, also allowing comparison with the discounted capital spend. This is done with the Social Time Preference Rate of 3.5%.

Constraint cost implications of interconnection

3.49 The impact on constraint costs is dependent on the location of the interconnector on the GB network and the level of onshore reinforcement built to accommodate the interconnector. Further detail regarding optimal locations to connect will be output based upon the constraint costs calculated on the network with the interconnectors under consideration.

3.50 Constraint costs are incurred on the network when power that is economically "in merit" is limited from outputting due to network restrictions. In this event, the ESO will incur balancing mechanism costs to turn down the generation which is not able to output and offer on generation elsewhere on the system to alleviate the constraint.

3.51 The output of the ETYS and NOA reports provides information on the current state and ongoing developments of the onshore network. This will be used to provide a general picture of the optimal network areas for accommodating interconnectors from certain countries. This will be based on constraint costs attributable to the interconnector under review. ETYS and NOA quantify the boundary limitations and present recommended options for reinforcement of the grid. This is intrinsically linked to the increasing presence of interconnection in the UK which can cause further strain on boundaries and potentially trigger investment in further reinforcements if the NOA process determines that to be the most economic and efficient course of action.

BID3 model

3.52 BID3 is the tool which will be used to perform the NOA IC 2019/20 and employed by the ESO to carry out a range of economic analysis.

3.53 BID3 is a Pan European Market Model created by Pöyry Management Consultants. BID3 will be used by National Grid to forecast the Socio-Economic Welfare (SEW) and the Attributable Constraint Costs (ACC).

3.54 A comprehensive guide to how National Grid uses BID3 for calculating constraints is available on our website[19]. It is an economic dispatch model which can simulate all ENTESO-E power markets simultaneously from the bottom up i.e. it can model individual power stations for example. It includes demand, supply and infrastructure and balances supply and demand on an hourly basis. BID3 models the hourly generation of power stations on the system, taking into account fuel prices, historical weather patterns, socio-economic welfare and operational constraints.

3.55 The GB electricity system in BID3 is represented by a series of zones that are separated by boundaries. Generators are allocated to their relevant zone based on where they are located on the network, and then the appropriate demand is allocated to that zone. The boundaries, which represent the actual transmission circuits facilitating the zonal connectivity, have a maximum capability that restricts the amount of power which can be securely transferred to across them.

3.56 The socio-economic welfare is calculated by summing the producer surplus, consumer surplus and interconnector revenue. The consumer surplus is the difference between the

[19] https://www.nationalgrid.com/sites/default/files/documents/Long-term%20Market%20and%20Network%20Constraint%20Modelling.pdf

value of lost load and the wholesale price. The producer surplus is calculated and summed per plant based upon their Short Run Marginal Cost and the wholesale price.

3.57 Case collections are used for hourly generation and demand profiles as well as solar and wind profiles. An extensive study has identified the average historic year in terms of Generation, Demand, Wind output, Solar Output, interconnector flows and hydrological year. This is an approved approach but has limitations and could potentially undervalue countries with a high level of renewable generation such as Nordic countries with significant levels of hydro power.

Options included in the assessment

3.58 As there are infinite combinations of markets and reinforcements, applying engineering judgement, the number of options has been reduced to 29 credible study cases. These 29 study cases will be assessed in all iterations across all four scenarios.

3.59 The options which will be assessed are included in Table 3. 3 below. The boundary reinforcements and zones refer to Figure 3. 1.

Table 3. 3 Options to be considered in the analysis

Market and Zone	Boundary Reinforcements	Market and Zone	Boundary Reinforcements
Belgium Zone 4	c	**Ireland Zone 2**	b
Belgium Zone 4	None	**Ireland Zone 2**	None
Belgium Zone 6	None	**Ireland Zone 3**	None
Belgium Zone 6	d + e	**Netherlands Zone 4**	c
Denmark Zone 4	c	**Netherlands Zone 4**	None
Denmark Zone 4	None	**Netherlands Zone 6**	None
Denmark Zone 7	None	**Netherlands Zone 6**	d + e
France Zone 5	None	**Norway Zone 1**	a + b
France Zone 5	d	**Norway Zone 1**	None
France Zone 6	None	**Norway Zone 2**	b
France Zone 6	d + e	**Norway Zone 2**	None
France Zone 6	d	**Spain Zone 5**	None
Germany Zone 4	c	**Spain Zone 5**	d
Germany Zone 4	None		
Germany Zone 4	f		
Germany Zone 7	None		

Interconnection Assessment Methodology

Optimisation of GB-Europe Interconnection Process

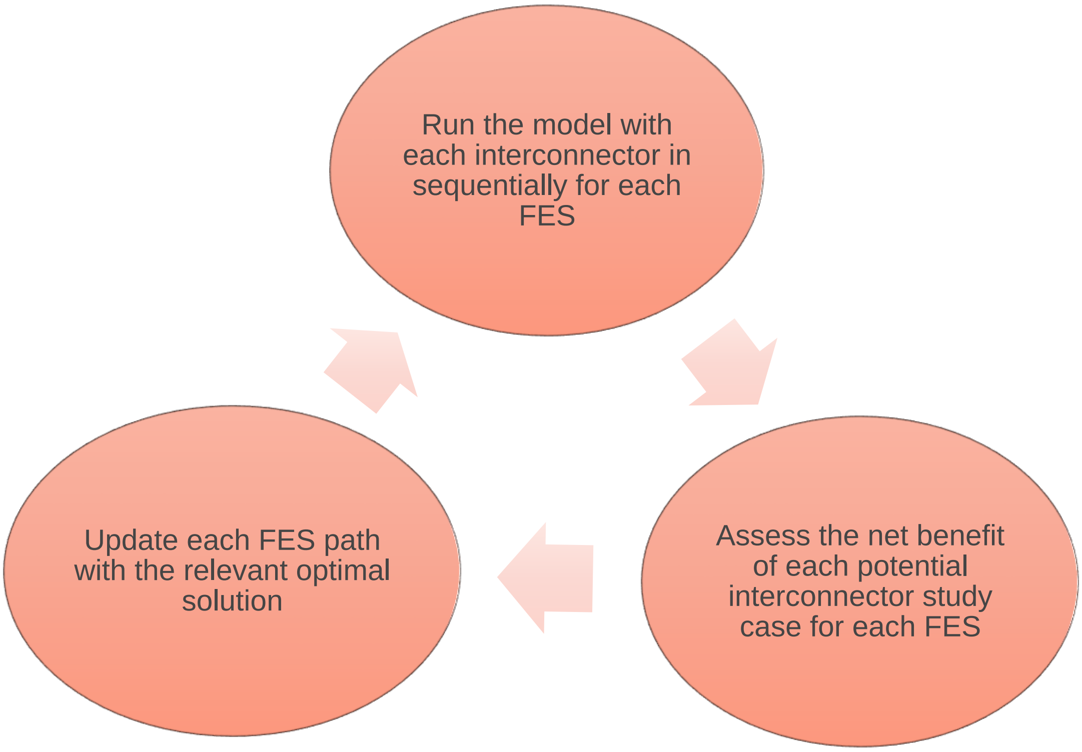


Figure 3. 4 Process summary

3.60 The optimisation of future interconnection capacities is a multivariable search, maximising the SEW less CAPEX less Attributable Constraint Costs (ACC) value. The decision variables are the total MW capacities (the sum of all interconnector transfer capacities) between GB and 8 adjacent markets, for both importing and exporting. These markets are national electricity markets- there is some level of coupling between many of them, however price areas (areas with the same electricity price throughout) generally align with nations. Where some nations have multiple price areas, such as Norway, interconnector projects will be assumed to be in the coastal price area deemed most likely for interconnection to the UK. The countries in question are: Norway; Denmark; Germany; The Netherlands; Belgium; France; Spain; and Ireland (which includes the Republic of Ireland and Northern Ireland). For each country's additional interconnector capacity, there will be a small number of zones and reinforcement combinations studied. The number of variables makes an exhaustive search within a useful timeframe infeasible - a search strategy must therefore be defined.

3.61 Due to the unique properties of the Icelandic market, any interconnection to Iceland which appears in the Future Energy Scenarios (FES) will remain in the background. Further Icelandic interconnection will be removed from the iterative process.

3.62 The search is just for interconnection to the UK. The level of interconnection between European markets will remain fixed throughout the scenarios (though could vary across future years). These levels are defined by the FES European scenarios.

3.63 The market studies, which model the physical limitations of transmission between markets (but not within markets) start from the baseline level interconnection. The interconnection capacities are then adjusted sequentially to search for improvements on this initial point, represented by an increase in the total SEW - CAPEX - ACC following the alteration of the capacity values. This total SEW-CAPEX-ACC value takes into account the whole asset life, such that the overall timing of connection is assessed in addition to the capacities per market.

Modelling inputs

3.64 The starting point of the process is National Grid's FES 2019 which includes generation plant ranking orders and demand forecasts across Europe for each scenario. FES 2019 will be the second time European markets are being varied by GB scenario to achieve more coherent, higher quality modelling. Output from NOA 2019/20 will be used to determine the high level boundary capacities which form the 7 zones included in the analysis. All interconnectors which are in the NOA IC baseline will be included in the model from 2027 (the first year of study).

3.65 The FES make forecasts of the future interconnection capacities in GB, per scenario. The FES level of interconnection is calculated on a project by project basis, reviewing all axioms from economic, political, environmental etc. An important distinction between the FES and this process, therefore, is that the NOA IC aims to find what would be economically optimal rather than being based on specific projects. A shortfall of interconnection baseline capacity relative to FES level of interconnection will then drive further interconnection in the results.

3.66 We have received feedback from several parties that we should revisit the approach of setting the baseline level of interconnection. It is important to state that NOA IC does not assess the viability of specific future projects: it does not “pick winners or losers” of actual projects. In NOA IC 2018/19 the interconnection baseline was based on all current interconnector projects and those with a high degree of regulatory certainty. We intend to set a baseline level of interconnection that avoids any unintended perceived project discrimination, and also allows a successful modelling output within defined modelling timescales. One option is to include within the baseline all projects currently under development, or all those with Project of Common Interest status, or all those on the National Grid ESO Interconnector Rregister. This on its own would result in too high a baseline intertconnection level, hence an “uncertainty factor” could be added equally to all of the projects included under development to produce a credible level of baseline interconnection. We will investigate this approach before commencing the NOA for Interconnectors 2019/20 and will provide additional information to our stakeholders.

3.67 The time period considered in the studies extends from the present to 2038. This is to match the FES, which will forecast up to 2039 in detail. For the timing analysis, only capacity in years 2027, 2029 and 2032 will be investigated. The reason for not starting to analyse additional capacity until 2027 is this is deemed the earliest an entirely new interconnector project could realistically be connected. Studying every year thereafter is infeasible, as each additional year studied requires a further set of model runs in the optimisation. This would lead to an unachievable number of required market simulations as constrained by time limitations.

Market modelling

3.68 The selected method of arriving at a recommendation for capacity development is an iterative optimisation per scenario. The iterative optimisation approach attempts to maximise present value, equal to SEW less CAPEX less Attributable Constraint Costs (ACC), using a search strategy. The whole process is repeated four times to arrive at an optimal development of capacity in each of the four FES. This year, like last year, based on strong stakeholder feedback, there will be no Least Worst Regret calculation at the end of each iterative step, resulting in four optimal paths: one per FES and hence a range for the optimal solution will be produced. A balance between computing resource and rigour in each step of the process must be found. An example step is outlined below, wherein multiple capacity changes are evaluated for SEW in each step.

3.69 Timing of capacity increases can affect the SEW generated and Attributable Constraint Costs (ACC) by the interconnection across the study window. Within each search step, therefore, timing combinations will be considered. The use of spot years will be necessary to allow a solution to converge, wherein the commissioning of additional projects would be evaluated only in future years 2026, 2028 and 2031. This means for each iteration, the welfare of the interconnectors in every spot year will be calculated.

3.70 The example below is based on a hypothetical situation, optimising the capacities and optimal timing of connection for potential interconnection to 4 markets. It shows a sample of the options of market, connecting year, FES scenarios, GB zone and reinforcement that need to be considered for each iterative step.

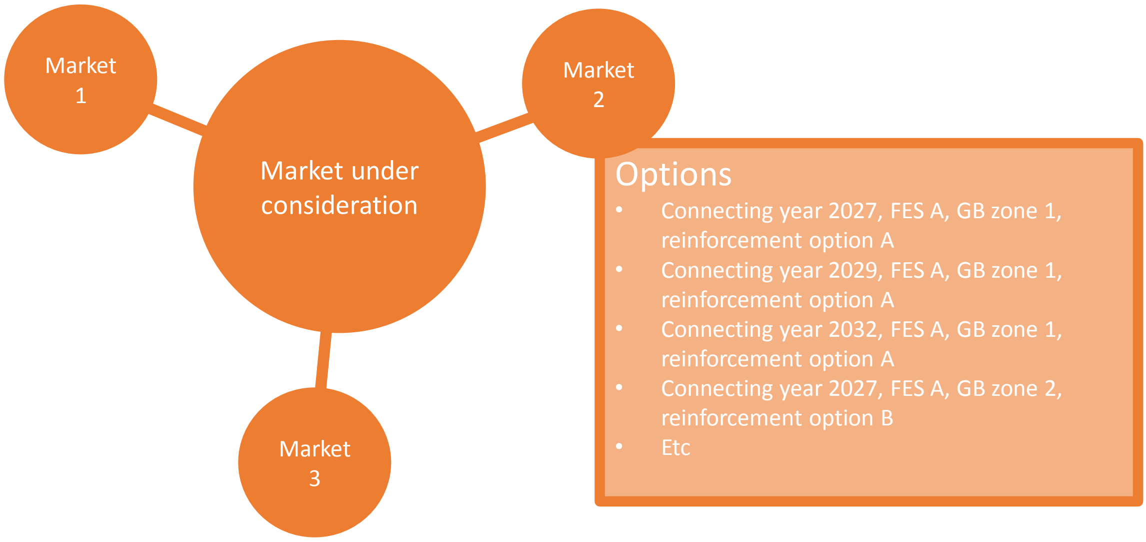


Figure 3. 5 Example Markets

Table 3. 4 Example of iteration 1 search step

	Iteration 1 Transfer Capacities (MW)						
	Baseline	Study case 1		Study case 2		Study case 3	
		Increment	Simulated capacity	Increment	Simulated capacity	Increment	Simulated capacity
FES A Market 1	2000	+1000	3000	0	2000	0	2000
FES A Market 2	1000	0	1000	+1000	2000	0	1000
FES A Market 3	1000	0	1000	0	1000	+1000	2000
FES A **CHANGE IN SEW-CAPEX-ACC**	**0**	**+ £12M**		**+ £5M**		**+ £8M**	

3.71 Table 3. 4 gives an example of the iteration search step 1, whereby an additional 1000 MW of capacity is added sequentially to each option. The option that produces the highest change in SEW-CAPEX-ACC for each FES (in this example study case 1, with an additional 1000MW interconnector to market 1) is then added to the baseline for the iteration search step 2 for that particular FES, as shown in Table 3. 5.

Table 3. 5 Example of iteration 2 search step

	Iteration 2 Transfer Capacities (MW)						
	Baseline	Simulation 1		Simulation 2		Simulation 3	
		Increment	Simulated capacity	Increment	Simulated capacity	Increment	Simulated capacity
FES A Market 1	3000	+1000	4000	0	3000	0	3000
FES A Market 2	1000	0	1000	+1000	2000	0	1000
FES A Market 3	1000	0	1000	0	1000	+1000	2000
CHANGE IN SEW – CAPEX-ACC	**0**	**+ £7m**		**+ £5M**		**+ £5M**	

FES A Market 1 Increased by 1000MW following the result of iteration 1 for FES A

3.72 The search finishes when it is deemed to have converged - that is, no further capacity alterations yield a higher overall present value for the whole study window for each scenario. The optimal capacity profiles will then be presented in the NOA report, providing the industry with a range, that is one for each FES.

3.73 To improve efficiency of arriving at the end of the optimal path, the incremental steps will be of 1000MW of capacity. Once there is no additional benefit from any interconnectors, the incremental capacity will be reduced to 500MW to analyse whether there is any benefit of a further 500MW.

Further Output

3.74 Accompanying the output of the optimal path market and network analysis, additional results will be provided illustrating the benefit each interconnector would potentially provide. This is to overcome this possibility of misinterpretation of the results, as many interconnectors which don't appear in the optimal path individually have a positive net benefit to consumers and therefore development should continue to be pursued.

Process Output

3.75 The above methodology will be employed to create a chapter of the NOA 2019/20 report. This chapter will present the main findings of the analysis – a range for optimised interconnection capacity level by market, and the best timing for capacity increases across all scenarios. It will include commentary on these results and other impacts of interconnection excluded from the optimisation. The analysis aims to provide stakeholders with a quantified assessment of the potential benefits of interconnection. The output from the 2019/20 NOA is used as in input into the NOA IC analysis for setting the baseline network reinforcement assumptions. The output of NOA IC does not feed directly into the creation of the next set of FES. The FES level of interconnection is calculated on a project by project basis, whereas NOA IC aims to find what would be economically optimal rather than being based on specific projects. Our stakeholders have restated that they want us to keep the level of detail similar to that within NOA IC 2018/19, but with greater insight. The results will be delivered by 31st January 2020.

4

Suitability for third party delivery and tendering assessment

Overview

4.1 The ESO has a clear role to play in facilitating the introduction of competition and supports competition where it is in the interest of consumers. As part of their licence change consultations[20] Ofgem have made clear their intention and applicability of the criteria for competition assessment. The ESO therefore believes it is sensible and pragmatic to continue to include an assessment for competition for major network reinforcements against these criteria of new, high value and separable as the timescales for delivery of many investments now fall in the RIIO-T2 timeframe, where any projects meeting the criteria could be subject to competitive tendering. As Ofgem develops the proposed competitive delivery frameworks and timing the ESO will continue to extend the assessment against the criteria for competition into connections where the enabling works meet the relevant criteria. This methodology describes the process for the assessment for both wider network reinforcement and connections. It should be noted that, in the current NOA, the time for the competitive tendering process is not considered when the TOs submit the EISDs or delivery dates for their wider transmission reinforcements or enabling works[21] for connection projects.

4.2 The ESO assesses the suitability of projects for competition in accordance with published tendering criteria[22]. The single year regret analysis process identifies the recommended options. For each set of options, the ESO identifies the most relevant options and assesses these options against the tendering criteria, which are options that are:

- new,
- separable,
- high value.

In order to undertake the assessment, the TOs will provide information to the ESO via the SRF form (see appendix D) for wider works. The ESO then carries out the following process:

- Reviews the information provided for each option.
- Assesses the most relevant options against the criteria for competition.
- Provides a recommendation for the options on how they meet or do not meet the criteria for competition and hence the options' suitability for competition.

Note that some options will clearly not meet the criteria for competition, for instance because their value is far below the threshold. As a result, not all options are assessed for competition.

4.3 In addition to wider network reinforcement, the NOA also examines connections for eligibility for competition. For each NOA, the ESO assesses transmission connections against the same criteria as wider work options (described above) and publishes the conclusions in the NOA. The assessment against the criteria does not mean that investments meeting the criteria will be subject to competitive tendering. Any decision for competitive tendering lies with Ofgem.

Connections

4.4 Prospective users can make connection applications and modification applications at any time of year whereas the NOA process works on an annual cycle. As a result the ESO assesses connection projects when it receives them. Few connection projects meet the value criteria of £100m and of those that do, many provide wider network benefits and hence are of interest and already included in the NOA process. The ESO uses the connection contract between the ESO and the prospective user to take a view of the likelihood of meeting the value criteria.

4.5 For a new connection, the ESO identifies the projects where there is the possibility of the required enabling works (not including works already covered in the NOA) meeting the value

[20] https://www.ofgem.gov.uk/publications-and-updates/statutory-consultation-modify-standard-condition-c27-electricity-transmission-licence

[21] For the definition of 'enabling works', please refer to section 13 of the Connection and Use of System Code (CUSC) https://www.nationalgrid.com/sites/default/files/documents/Complete%20CUSC%20-%20%201%20April%202018.pdf

[22] https://www.ofgem.gov.uk/system/files/docs/2018/01/competition_update.pdf and https://www.ofgem.gov.uk/system/files/docs/2018/01/draft_criteria_guidance.pdf

criteria. The ESO informs the relevant TO(s) of the projects and provides a summary of the work proposed and the costs. This is in time for the ESO to perform the assessment in October.

4.6 If the TO states that a project has wider network benefits, it can use the SRF at the usual time in the NOA process to submit the information for the competition assessment process.

4.7 The TO(s) responds to the ESO's summary of the projects and the ESO then uses the summary together with any input from the TO(s) for the process to assess eligibility for competition.

Bundling/splitting of work packages

4.8 The first step in the ESO's competition assessment of larger projects, is to provide an opinion on bundling projects into larger packages, or splitting projects into smaller packages, to form a recommendation in the NOA. There are two aspects to the ESO's consideration of bundling and splitting as follows:

- The costs and size of the component aspects of projects to ensure that they can be most appropriately packaged.
- Where the ESO can identify opportunities or benefits from repackaging of projects.

Bundling

4.9 The ESO considers whether combining one or more projects into a single tender could be appropriate (if they have common needs/drivers or it makes technical or commercial sense) and whether it is in the interests of consumers (e.g. economies of scale for procuring large quantities). If the ESO believes that there is benefit from bundling (and where the constituent projects have not been challenged or corrected), then each constituent project should meet the high value threshold. Where work is bundled as part of this process, the component parts must each meet the competition criteria to be eligible.

Splitting

4.10 The ESO is expected to recommend splitting a project into more than one tender package if it is in the interest of consumers (for example if a project constitutes new assets and refurbishment of existing assets these could be split so new assets could be competed). When it considers splitting a project, the ESO will consider the impact this could have on project delivery. Each resultant package should meet the high value threshold, if these are to be competed.

Competition criteria

4.11 Ofgem has stated that there are significant benefits to consumers in introducing competition into the delivery of transmission projects that meet defined criteria. These criteria are:

- **New** – completely new transmission assets or complete replacement of transmission assets.
- **Separable** – ownership between these assets and other (existing) assets can be clearly delineated.
- **High value** – at or above £100m in value of the expected capital expenditure of the project.

Figure 4. 1 shows the process for assessing whether reinforcement projects meet competition criteria.

4.12 Note that there are two stages in the high value assessment (red outline) and two stages in the separability assessment (green outline).

4.13 Process stages - the names of the process stages below match those on the diagram. The numbered stages below correspond to the boxes on the left side of the diagram.

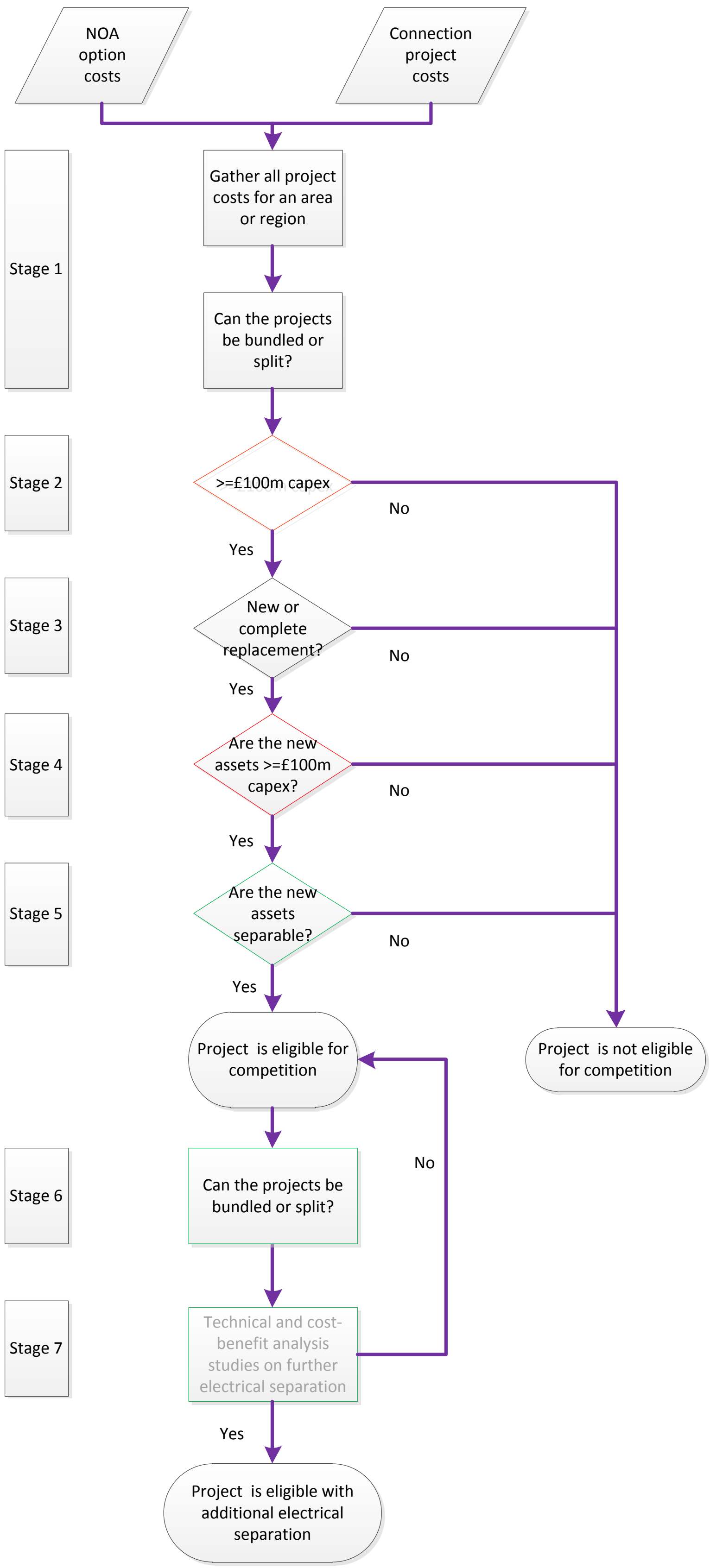


Figure 4. 1 The process for assessing suitability for competition

Stage 1

Can the projects be bundled or split?

Aim – to carry out a first check to ensure that sensible packages of work are developed together by assessing the proposed work to see if it should be split (broken into more than one smaller bundle) or whether work across more than one project should be bundled together.

Considerations when assessing potential for splitting:

- Does the project involve different technologies that suggests different skills and procurement are needed for the separate elements?
- Is there a variety of works involved? For example:
- Are there one or more new substations?
- Does the proposed project comprise OHL and cable sections and how do they affect existing networks?
- Are there one or more cable tunnels?
- Are the project phases adjoining or in naturally separate timeframes?
- Could the resulting work package lead to stranded investments?

Considerations when assessing the potential for bundling:

- Are there multiple projects with common needs / drivers?
- Are there several individual projects in a relatively self-contained area or corridor?
- Are there scheme works that are very similar?
- Is it one of several smaller projects that could be efficiently or more efficiently developed with other projects?

Stage 2

>=£100m capex

Aim – to assess whether the project or bundle of projects meets the high value criteria and include only projects that exceed the threshold within a 10% margin for consideration at the next stage.

Table 4. *1* lists the factors that affect the high value figure.[23]

Criteria – this is the first of a two-stage process (the second, stage 4 is below). The ESO uses the costs that the TO(s) have provided and that have undergone cost checking or that appear in the connection contract to calculate the cost (or where we are looking to create a bundled package the total costs) of the project. The ESO might seek advice from the TO if it has queries. The trigger threshold is set at £90m to highlight projects that are marginally below the £100m figure. This produces a straight yes/no output.

Table 4. 1 List of factors that the high value figure includes or excludes

The £100m capex 'high value' figure	
includes	**excludes**
• Costs of acquiring land • Costs of complying with consents conditions	• Costs of gaining consent

[23] As applied to the current framework for cost allocation under the RIIO-T1 framework

Stage 3

New or complete replacement

Aim – to test the projects against whether they are new assets or complete replacement assets rather than, say, refurbished assets. This test has the practical benefit of checking for complicated examples. For example, where a new double circuit crosses an existing double circuit and because of routing and the existing circuits, the existing circuits need modification leading to new assets integrated into existing circuits. Thus, the affected existing circuits would become a mix of old and new assets. The consenting process might also change a simple double circuit route into a complicated one that includes mixed ownership because of old and new assets being integrated. As the project, will be assessed annually in the NOA process this might lead to a change in the project’s eligibility, from one year’s assessment to another.

Criteria – is a project delivering completely new assets or complete replacement assets that fulfil the same function of the assets to be removed or replaced? This produces a straight yes/no output.

Stage 4

Are the new assets >=£100m value?

Aim – to test whether the new assets reach or exceed the high value threshold.

Criteria – this is the second part of a two-stage process (the first, stage 2 is above). If the project has a very high proportion of new assets and high value, the project will pass this stage. For more marginal projects, the ESO uses the breakdown of costs from the TO to calculate the value of the new assets. This produces a straight yes/no output.

Stage 5

Are the new assets separable?

Aim – to test whether the project details indicate that the new assets are readily separable from the existing assets.

Criteria – this is to check if the project already has points of connection to existing assets that can be clearly delineated, in other words, clearly identified. Disconnectors are obvious points that can be delineated but Ofgem suggest that other points such as clamps on busbars would also be acceptable as long as the point can be clearly identified. This produces a straight yes/no output.

Stage 6

Can the projects be bundled or split?

Aim – having gone through the process to check for eligibility, this stage is a recheck that sensible packages of work are developed together.

Criteria – these are the same as for stage 1 (above). Note that projects that are split must have component parts that meet or exceed the £100m value threshold.

Stage 7

Based on technical and cost-benefit analysis studies, is it appropriate for the ESO to recommend additional electrical separation for the projects that have met the competition criteria?

If the ESO concludes that the project proposals already have adequate electrical separation, it is not necessary to carry out this stage.

Aim – use cost-benefit analysis studies to test technical solutions and determine if it is worth extra investment in assets or amending the design to further delineate ownership boundaries to provide adequate electrical separability.

The ESO is considering ways of conducting this assessment with the most likely being a study against some criteria to provide consistency. The ESO believes that the assessment will be needed by exception only.
The ESO maintains a log of connection projects that meet the competition criteria and liaises with the TOs about the outcomes of the competition eligibility assessments. This log forms the basis of the list that is published in the NOA.

5

ESO process for Offshore Wider Works

Foreword

5.1 This section contains National Grid ESO's proposed processes for Offshore Wider System Works in the following two areas:

5.2 **Offshore Wider Works – Developer Associated** describes the process for investment in transmission capacity to provide wider network benefit, which is led by developers (whether generator builds or OFTO build). It includes investment in offshore transmission assets or capacity that goes beyond that needed by a single developer and is for the purpose of supporting the reinforcement of the GB transmission network (the wider network). This could include investment providing for, or creating the potential for, increased boundary transfers between different zones of the wider network via offshore links.

5.3 **Offshore Wider Works – Non Developer Associated** describes the process for investment that would support reinforcement of the wider transmission network, but where developers are unwilling or unable to take forward the offshore wider works. Offshore Wider Works Non Developer associated Needs Case is in many cases a substitute for onshore wider works.

Offshore Wider Works – Developer Associated overview

5.4 Current offshore transmission assets have been developed as standalone connections to shore known as radial connections. However, the Round 3 offshore wind projects are larger, more complex and at a greater distance from shore than those that have been developed so far. As a result there is likely to be the potential for efficiencies from greater coordination of offshore transmission infrastructure. This could include coordination between connections, and coordination of the strategic development of the wider network through offshore reinforcement projects.

5.5 Developer Associated Offshore Wider Works is investment in transmission capacity to provide wider network benefit, which is led by developers (whether generator builds or OFTO builds). It includes investment in offshore transmission assets or capacity that goes beyond that needed by a single developer and is for the purpose of supporting the reinforcement of the GB transmission network (the wider network). This could include investment providing for, or creating the potential for, increased boundary transfers between different zones of the wider network via offshore links.

5.6 The offshore connection offer process has a key role in the development of a coordinated offshore transmission network. Where it is economic and efficient, Offshore Wider Works may form part of a developer's connection offer and subsequent bilateral connection agreement (BCA)[24].

5.7 In the December consultation, Ofgem proposed high level roles and responsibilities to support a gateway assessment process for Offshore Wider Works. In responding to the Ofgem proposals, stakeholders broadly agreed that the ESO should support the Needs Case for Developer Associated Offshore Wider Works at the gateway assessments. Ofgem maintains the position that the developer should lead in triggering and making submissions to the voluntary gateway assessments, and that the ESO (drawing on relevant Transmission Owners (TOs) as necessary) should assist with developing the Needs Case for the Offshore Wider Works for any Ofgem gateway assessments. Further, both parties will have a role in monitoring the Needs Case for the Offshore Wider Works, with the developer reviewing their design where this is an appropriate response to a change in the Needs Case.

5.8 Ofgem at this stage, consider that offshore developers should retain the choice to undertake preliminary Offshore Wider Works for the development of coordinated offshore transmission assets under a Developer Associated Needs Case.

[24] In planning and developing offshore transmission assets under the generator build option, developers are required under the Grid Code (Planning Code) to take into account reasonable requests from the NETSO where it is reasonable and practicable to do so (PC.8.3)

Offshore Wider Works – Developer Associated: the ESO's role

5.9 Based on the consultation document from December 2013 a majority of the respondents agreed that the ESO should support the Needs Case for Developer Associated Offshore Wider Works. It was also very clear from the consultation that affected TO and offshore developer's contribution and cooperation would be also required. The following text is explaining each point of the ESO process for Developer Associated Offshore Wider Works.

5.10 Step 1: Identification of System Need. The Offshore Wider Works can be identified in two ways:

a. The ESO assess the system need through the annual Electricity Ten Year Statement (ETYS) process. Some of the system reinforcement options will be Offshore Wider Works options and will be subsequently included in the NOA document.
b. Offshore Wind Farms Connection offers will also identify the investment need for the Offshore Wider Works.

5.11 Step 2: Offshore Wind Farm Connection Application and CION

a. As part of the connection offer process, the ESO is required to provide details to the developer of the preliminary identification and consideration of the connection options available. This includes the preliminary costs used in assessing such options and the offshore works assumptions, including the assumed interface point identified. The ESO fulfils these requirements by the production of the Connections Infrastructure Options Note (CION). The CION sets out the offshore works assumptions and consideration of options available and is provided to the developer during the connection offer process.

5.12 Step 3 & Step 4: The ESO and offshore developer are working together on development of the Offshore Wider Works Options

a. In collaboration with the offshore developer, the ESO develops the Offshore Wider Works options.
b. In developing Offshore Wider Works, the ESO will take into consideration two major transmission system design criteria: network capacity availability of the local boundary and shortfall of the wider system boundaries.
c. According to Chapter 2 of the NETS SQSS – Generation Connection design, the transmission system is designed to accommodate 100% of the transmission entry capacity at the connection point within a local boundary (e.g. for a 1GW wind farm connection, the onshore system is designed to accommodate the complete 1GW generation and the offshore assets are sized to provide this full transmission entry capacity.)
d. In planning the Main Interconnected Transmission System (MITS) however, different scaling factors are applied to different types of generating. In the case of wind, this implies that the assets are not assumed to be 100% utilised by the wind generated. Taking into account all these scaling factors, the offshore infrastructure is allowing some spare capacity in the assets. It is this 'spare' capacity that provides the opportunity for offshore wider works to be utilised as one of the options to provide boundary capability. In providing the Offshore Wider Works design it is crucial the ESO and offshore developer work together and agree on the generation background, scenarios and sensitivities which will be used as a basis for the Offshore Wider Works Design. In this stage the ESO will inform Ofgem on the agreed background and scenario between ESO and offshore developer.
e. The benefits of the Offshore Wider Works will also be assessed by utilising a combination of operational actions to maximise the capability across the boundaries (e.g. actions included QB optimisation and redirection of flows in HVDC links).
f. Once the ESO and the offshore developer agree on Offshore Wider Works options, the agreed Offshore Wider Works options are progressed into the cost-benefit analysis.

5.13 Step 5: Cost-benefit analysis. The ESO, supported with information from the offshore developer, perform the cost-benefit analysis on the agreed Offshore Wider Works options from Step 3 & 4. The rationale behind the Cost-benefit analysis is explained in the following text:

a. The key economic objectives for cost-benefit analysis for Offshore Wider Works are:

v. Ensure value for money for the consumers by delivering cost effective reinforcements to ensure economically efficient design and operation of the network.

vi. Timely delivery of necessary reinforcement(s) to minimise any cost exposure for consumers to either early investment or delayed implementation.

b. The objectives for Offshore Wider Works cost-benefit analysis are:

i. To be consistent with Licence obligations and National Electricity Transmission System (NETS) Security and Quality of Supply Standards (SQSS); the analysis promotes economic and efficient investment.
ii. To present economic justification for the preferred Offshore Wider Works designs and an explanation of how they compare with the alternative counterfactual case.
iii. To present evidence on expected long-term value for money for consumers considering a range of sensitivities
iv. To present evidence on optimal timing of the preferred reinforcement option.

c. Driven by these objectives the scope of the cost-benefit analysis is:

i. To establish the reference case position in terms of constraint costs forecasts associated with the 'do minimum' network state, across different generation background scenarios.
ii. To model the economic impact, measured as constraint cost savings, for a range of designs, across a range of scenarios.

d. To undertake a cost-benefit analysis by:

i. Appraising the economic case of the options by adopting the Spackman[25] approach and determining respective Net Present Values (NPVs) across the studied generation scenarios and sensitivities.
ii. Establishing worst regrets associated with each design/technology appraised.
iii. Identifying the Least Worst Regret option overall
iv. Assessing the impact of key sensitivities: increase in capital expenditure, and delays in delivery timeframes.
v. Make recommendations for the preferred option i.e. the Least Worst Regret solution, taking into consideration the impact of sensitivities.

5.14 Step 6: The ESO discusses the preferred Offshore Wider Works option from cost-benefit analysis (Step 5) with the offshore developer and affected TO

5.15 Step 7: Offshore Wider Works Needs Case submission through the voluntary gateway process

a. The ESO makes a recommendation on preferred option for Developer Associated Offshore Wider Works. The ESO supports the offshore developer in its submission of the Offshore Wider Works Needs Case to Ofgem via voluntary gateway process
b. Based on the last consultation in December 2013 offshore developers will have the option to go through one or two Ofgem gateway assessments, timed broadly ahead of the commencement of preliminary works and ahead of construction works. Where a developer is comfortable that it can support its decision to develop the Offshore Wider Works as part of a cost assessment during a tender exercise, the developer can choose not to go through one, or both, of the gateway assessments. In general, Ofgem is expecting that two voluntary gateway assessments would be sufficient. However, if a developer considers that there are substantial benefits to passing through more than two gateway assessments in a particular case (for example in the case of particularly large, complex projects) Ofgem would look to engage with the developer to understand these benefits and consider the best way forward.
c. At the first gateway assessment, Ofgem will review the rationale for including the Offshore Wider Works in a developer's design solution at the preliminary works stage.

[25] The Joint Regulators Group on behalf of UK's economic and competition regulators recommend a discounting approach that discounts all costs (including financing costs as calculated based on a Weighted Average Cost of Capital or WACC) and benefits at the Social Time Preference Rate (STPR). This is known as the Spackman approach. Further details of our assumptions regarding WACC and STPR are presented later in this document.

This is the case for developers following both the generator build and OFTO build option. Where Ofgem is convinced by the developer's rationale for undertaking certain preliminary works associated with the Offshore Wider Works, Ofgem would not reassess this rationale during the tender exercise.

d. At the second gateway Ofgem will review the rationale for constructing the Offshore Wider Works. Where the developer chooses the generator build option, the Ofgem assessment at the second gateway will inform the cost assessment process undertaken during the subsequent tender exercise. Where Ofgem is convinced by the developer's rationale for including specific additional, or oversized, transmission assets associated with the Offshore Wider Works, Ofgem would commit to not reassessing this rationale during the tender exercise. Where a developer is following the OFTO build option, the Ofgem assessment will help to inform the scope of the OFTO build tender exercise.
e. Any Ofgem commitment regarding not re-assessing the rationale for the Offshore Wider Works at the first or second gateway, would be conditional on the ESO and the offshore developer continuing to engage and monitor the Needs Case for the Offshore Wider Works. Where the Needs Case changes, Ofgem expects these parties to review the design of the offshore assets and make any necessary changes where this would be economic and efficient. Ofgem is expecting that this process would take into account both the needs of the wider network and the impact of any changes on the cost and timing of an offshore developer's connection. In some instances, a change in the Needs Case for the Offshore Wider Works may mean that the Offshore Wider Works is no longer taken forward.
f. All the costs incurred in connection with development and construction of the agreed scope of the transmission assets, including the Offshore Wider Works elements, would remain subject to the economic and efficient test as part of Ofgem's cost assessment.

5.16 Step 8: Voluntary Gateway Process Assessment

a. 1st gateway assessment (preliminary works): The developer, supported by the ESO, may submit a Needs Case for the Offshore Wider Works to Ofgem. Where a robust Needs Case is submitted, Ofgem makes commitments on approach to cost assessment on the rationale for Offshore Wider Works preliminary works.
b. 2nd gateway process: The developer, supported by the ESO, may submit a Needs Case to Ofgem. Where a robust Needs Case is submitted, Ofgem make commitments on approach to cost assessment on the rationale for Offshore Wider Works construction works.
c. Tender Exercise: The developer triggers a tender exercise Ofgem conducts a cost estimate and assessment, taking into account commitments at the 1st and 2nd gateway assessments.
d. In the 2013 December consultation Ofgem proposed a number of high level criteria that would be used to evaluate gateway assessment submissions. These criteria included:
    i. the (economic) Needs Case for investment
    ii. the timing and scope of the project and its technical readiness
    iii. proposals for ongoing ESO-developer engagement
e. Gateway assessments will, in general, be expected to take place before a tender exercise has commenced. As the purpose of the gateway assessment is to inform a resulting tender exercise cost assessment, Ofgem expect the developer to be able to show their commitment to triggering a tender exercise for those assets before Ofgem undertake a gateway assessment.
f. Timing of the Gateway process
    iv. In 2013 consultation Ofgem proposed providing flexibility in the timing of gateway assessments, driven by the needs of individual projects. The identified flexibility applied to the point at which the developer would trigger the gateway assessment, based on the developer's ability to provide sufficient information to enable Ofgem to conduct an informed assessment. Ofgem expect that early engagement between developers and Ofgem would inform the point at which the gateway assessment would be triggered.
    v. Developers and the ESO will need to undertake analysis to provide an evidence of the feasibility and Needs Case for taking forward the Offshore Wider Works before considering triggering the first gateway assessment. Ofgem is considering that

developers will generally only be able to satisfy the assessment criteria for the first gateway assessment after they have signed a BCA. Ofgem expect that in most cases there may need to be significant further engagement on connection optioneering between the developer and the ESO in order to inform a Needs Case submission. Ofgem also expect early engagement between developers and Ofgem will help inform when the gateway assessment should be triggered.

vi. Similarly, for the second gateway assessment, developers will be able to trigger the gateway assessment when they have sufficient information to enable Ofgem to conduct an informed assessment. Under the generator build option, Ofgem expect the timing of this gateway assessment to be as late as possible, to help ensure that the evidence provided in an offshore developer's submission remains up to date at the point at which significant final procurement decisions for the Offshore Wider Works are made.

5.17 Step 9: The ESO and offshore developers are providing support to Ofgem in the Gateway Assessment Process

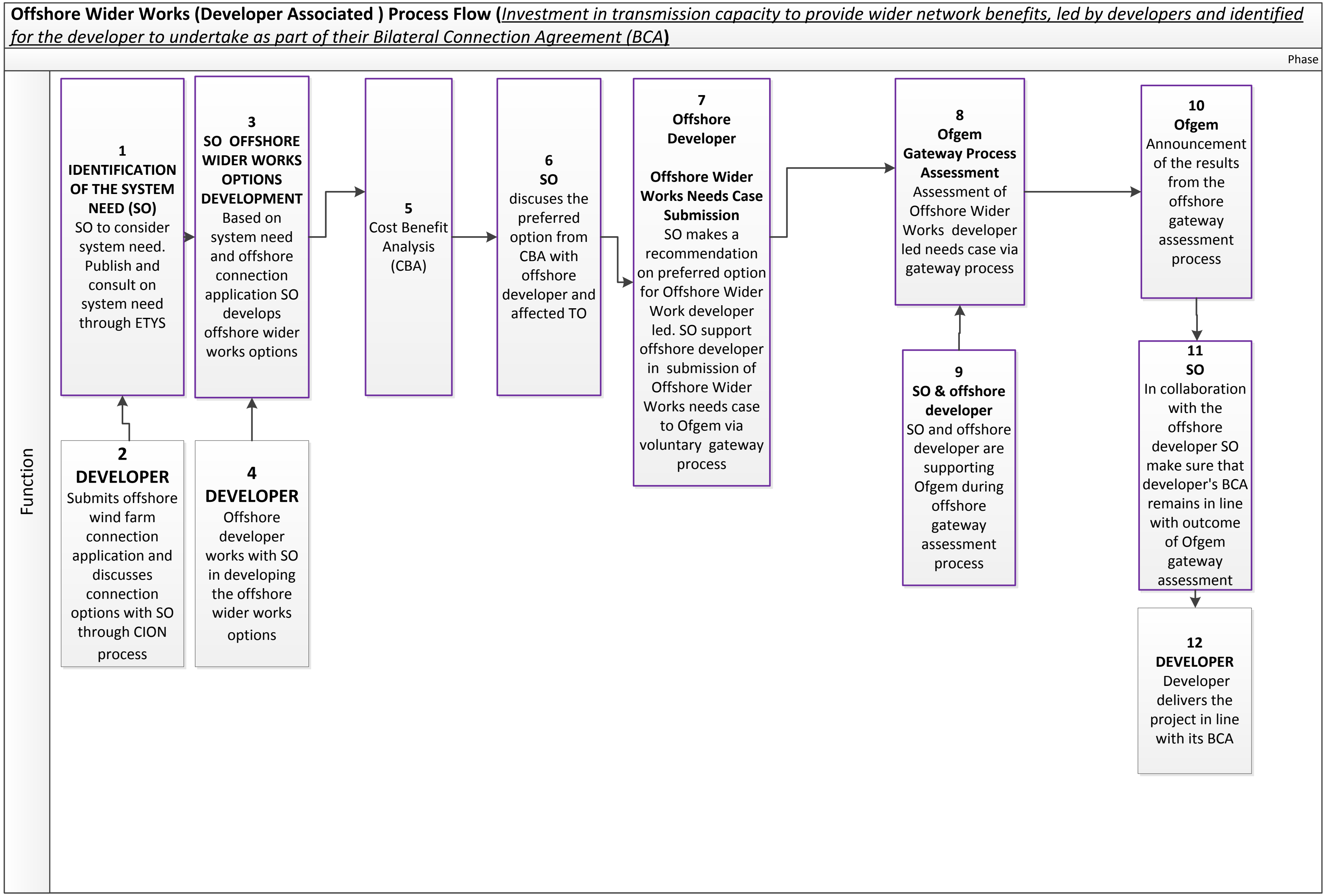
i. Ofgem will be working with the ESO and offshore developer to further develop what information for the gateway assessment process is required. The criteria and Needs Case requirements will be applicable to all projects, ensuring transparency of approach. However, given the unique technical requirements of offshore transmission and variation between projects, early engagement with developers ahead of a gateway assessment submission will provide an opportunity for Ofgem to provide further details on what information will need to be contained within an individual gateway assessment submission

5.18 Step 10: Ofgem approves the Developer Associated Offshore Wider Works project

5.19 Step 11: In collaboration with the offshore developer, the ESO makes sure that the developer's BCA remains in line with the outcome of Ofgem's gateway assessment process

5.20 Step 12: The Offshore developer delivers the project in line with the BCA.

Offshore Wider Works – Developer Associated process flow diagram



This diagram shows the overall Offshore Wider Works process. The text in each box corresponds to the descriptions of the stages explained in general process above. The numbers correspond to the step numbering in the text.

Offshore Wider Works – Non Developer Associated overview

5.21 Current offshore transmission assets have been developed as standalone connections to shore known as radial connections. However, the Round 3 offshore wind projects are larger, more complex and at a greater distance from shore than those that have been developed so far. As a result there is likely to be the potential for efficiencies from greater coordination and integration of offshore transmission infrastructure. This could include coordination between offshore connections, and coordination of the strategic development of the wider network through offshore reinforcement projects.

5.22 Existing offshore transmission assets are designed as a radial links to allow the transfer of the power from the offshore generator to the onshore network, and are therefore the offshore asset rating is equal to the size of the wind farm. The Non Developer Associated Offshore Wider Works is investment that would support reinforcement of the wider transmission network, but where developers are unwilling or unable to take forward the offshore wider works. An Offshore Wider Works Non Developer associated Needs Case is in many cases a substitute for onshore wider works, and therefore is some way very similar to onshore wider works investment.

5.23 Currently there is no clear route for Offshore Wider Works to be taken forward where works are not being undertaken by a developer. In the last consultation in 2014, Ofgem set out their lead option: for onshore Transmission Owners (TOs) to undertake preliminary works[26] for Non Developer Associated Offshore Wider Works, followed by a late OFTO build tender to identify an OFTO to construct, operate and own the transmission assets.

5.24 As a result of the consultation responses, Ofgem also considered other potential models for Non Developer Associated Offshore Wider Works.

5.25 The potential future models for Non Developer Associated Offshore Wider Works are the following:

a. **Split OFTO Build**: an initial tender to determine a third party to undertake the preliminary works, followed by a late OFTO build tender to determine the party who will construct and own the assets
b. **Early OFTO Build:** an early OFTO build tender to determine the party with responsibility for preliminary works, construction and ongoing operation of the assets
c. **TO Initiated Late OFTO Build:** enabling TOs to undertake preliminary works ahead of a late OFTO build tender to determine the party who will construct, own and operate the assets.

[26] 'Preliminary works' is a defined term in the 2013 Tender Regulations. Generally, it includes project development activity ahead of construction and does not include construction activities. For the purposes of this consultation, the definition of preliminary works within the 2013 Tender Regulations may be used as a guide, recognising that the scope of preliminary works under different Non Developer Associated WNBI models may ultimately vary from the current definition depending on the most appropriate scope of works for Non Developer associated Offshore Wider Works projects.

Offshore Wider Works – Non Developer Associated process

5.26 The coordination of offshore transmission assets could reduce the costs of the onshore system reinforcement requirements and potentially reduce the costs for the end consumers.

5.27 A Non Developer Associated wider network benefit investment for Offshore Wider Works supports coordination of the development of offshore transmission assets and wider GB transmission network reinforcement. Offshore Wider Works Non Developer associated is not limited to a specific connection offer and is the case where offshore generators are unwilling or unable to take forward the offshore wider works.

5.28 The following text describe the steps of the ESO process for the Offshore Wider Works Non Developer Associated Needs Case.

5.29 Step 1: Identification of system need. The need for Non Developer Associated Offshore Wider Works will be identified by the ESO and the relevant TO. The system need for the Offshore Wider Works can be identified in the following ways:

a. The ESO assesses the system need through the annual Electricity Ten Year Statement (ETYS) process, which subsequently informs the NOA Report.
b. The ESO and TOs regularly discuss and review network capacity issues and the need for network reinforcement in a particular TO's area at Joint Planning Committee (JPC) meetings. Based on that information a TO will consider Offshore Wider Options as an option to reinforce the network.

5.30 Step 2: ESO and relevant TO identify the Offshore Wider Works Options

a. In collaboration with the relevant TO, the ESO develops the Offshore Wider Works options.
b. In developing Offshore Wider Works, the ESO will take into account two major transmission system design criteria: network capacity availability of local boundary and shortfall of the wider system boundaries.
c. According to Chapter 2 of the NETS SQSS – Generation Connection design, the transmission system is designed to accommodate 100% of the transmission entry capacity at the connection point within a local boundary (e.g. for 1GW wind farm connection, the onshore system is designed to accommodate the complete 1GW generation and the offshore assets are sized to provide this full transmission entry capacity.)
d. In planning the Main Interconnected Transmission System (MITS) however, different scaling factors are applied to different types of generating. In the case of wind, this implies that the assets are not assumed to be 100% utilised by the wind generated. Taking into account all these scaling factors, the offshore infrastructure is allowing some spare capacity in the assets. It is this 'spare' capacity that provides the opportunity for offshore wider works to be utilised as one of the options to provide boundary capability.
e. In providing the Offshore Wider Works design it is crucial the ESO and affected TO work together and agree on the generation background, scenarios, and sensitivities which will be used as a basis for the Offshore Wider Works designs. In this stage, the ESO will inform Ofgem on the agreed background and scenario which will form the basis for the Offshore Wider Works designs.
f. The benefits of the Offshore Wider Works will be also assessed by utilising a combination of operational actions to maximise the capability across the boundaries (e.g. actions included QB optimisation and redirection of flows in HVDC links).
g. Once the ESO and the affected TO agree on the Offshore Wider Works options, the agreed Offshore Wider Works options are progressed into the cost-benefit analysis.

5.31 Step 3: Cost-benefit analysis. The ESO will perform the cost-benefit analysis on the agreed Offshore Wider Works options from Step 2. The ESO will lead the cost-benefit analysis depending on the preferred model for the Non Developer Associated Offshore Wider Works.

5.32 In the model 1 (Split OFTO build) the preferred Offshore Wider Works options will be obtained in collaboration between TO and 3rd party. The 3rd party will be defined by Ofgem via tendering process.

5.33 In model 2 (Early OFTO build) the preferred option will be identified in collaboration between the ESO and OFTO. The OFTO will be appointed by Ofgem via tendering process.

5.34 In the model 3 (Initiated late OFTO build) the preferred option will be determined in collaboration between the ESO and affected/relevant TO.

5.35 The Cost-benefit analysis will be performed by the ESO and the objectives and scope of the cost-benefit analysis is explained below:

a. The key economic objectives for cost-benefit analysis for Offshore Wider Works are:

   i. Ensure value for money for the consumers by delivering cost effective reinforcements to ensure economically efficient design and operation of the network.
   ii. Timely delivery of necessary reinforcement(s) to minimise any cost exposure for consumers to either early investment or delayed implementation.

b. The objectives for Offshore Wider Works cost-benefit analysis are:

   i. To be consistent with Licence obligations and National Electricity Transmission System (NETS) Security and Quality of Supply Standards (SQSS), the analysis promotes economic and efficient investment.
   ii. To present economic justification for the preferred Offshore Wider Works designs and an explanation of how they compare with the alternative counterfactual case.
   iii. To present evidence on expected long-term value for money for consumers considering a range of sensitivities
   iv. To present evidence on optimal timing of the preferred reinforcement option.

c. Driven by these objectives the scope of the cost-benefit analysis is:

   i. To establish the reference case position in terms of constraint costs forecasts associated with the ‘do minimum’ network state, across different generation background scenarios.
   ii. To model the economic impact, measured as constraint cost savings, for a range of designs, across a range of scenarios.

d. To undertake a cost-benefit analysis by:

   i. Appraising the economic case of the options by adopting the Spackman[27] approach and determining respective Net Present Values (NPVs) across the studied generation scenarios and sensitivities.
   ii. Establishing worst regrets associated with each design/technology appraised.
   iii. Identifying the Least Worst Regret option overall
   iv. Assessing the impact of key sensitivities: increase in capital expenditure, and delays in delivery timeframes.
   v. Make recommendations for the preferred option i.e. the Least Worst Regret solution, taking into consideration the impact of sensitivities.

5.36 **Model 1: Split OFTO Build**

a. Under the Split OFTO Build model, the preliminary works would be completed by a third party appointed through an Ofgem-run tender. If there is a Needs Case to proceed with construction, Ofgem would then run a late OFTO build tender. At the completion of the preliminary works, Ofgem would appoint an OFTO licensee to take ownership of the preliminary works and construct, own and operate the transmission assets.
b. Ofgem would run a first tender to license a third party to undertake the preliminary works and develop the project through to the securing of consents. Ofgem would select the successful bidder on the basis of the price of bids to complete the preliminary works as well as the evidence the bidder provides on its plans, capability and experience.

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[27] The Joint Regulators Group on behalf of UK’s economic and competition regulators recommend a discounting approach that discounts all costs (including financing costs as calculated based on a Weighted Average Cost of Capital or WACC) and benefits at the Social Time Preference Rate (STPR). This is known as the Spackman approach. Further details of our assumptions regarding WACC and STPR are presented later in this document.

c. The successful bidder would complete the preliminary works and produce the relevant outputs needed to run a late OFTO build tender. The party undertaking the preliminary works would be expected to engage stakeholders and coordinate with other relevant parties, including affected developers, TOs and the ESO. It would also be expected to support the eventual late OFTO build tender, undertaking activities such as populating the data room, responding to queries from bidders, and contributing to a smooth and timely tender process.

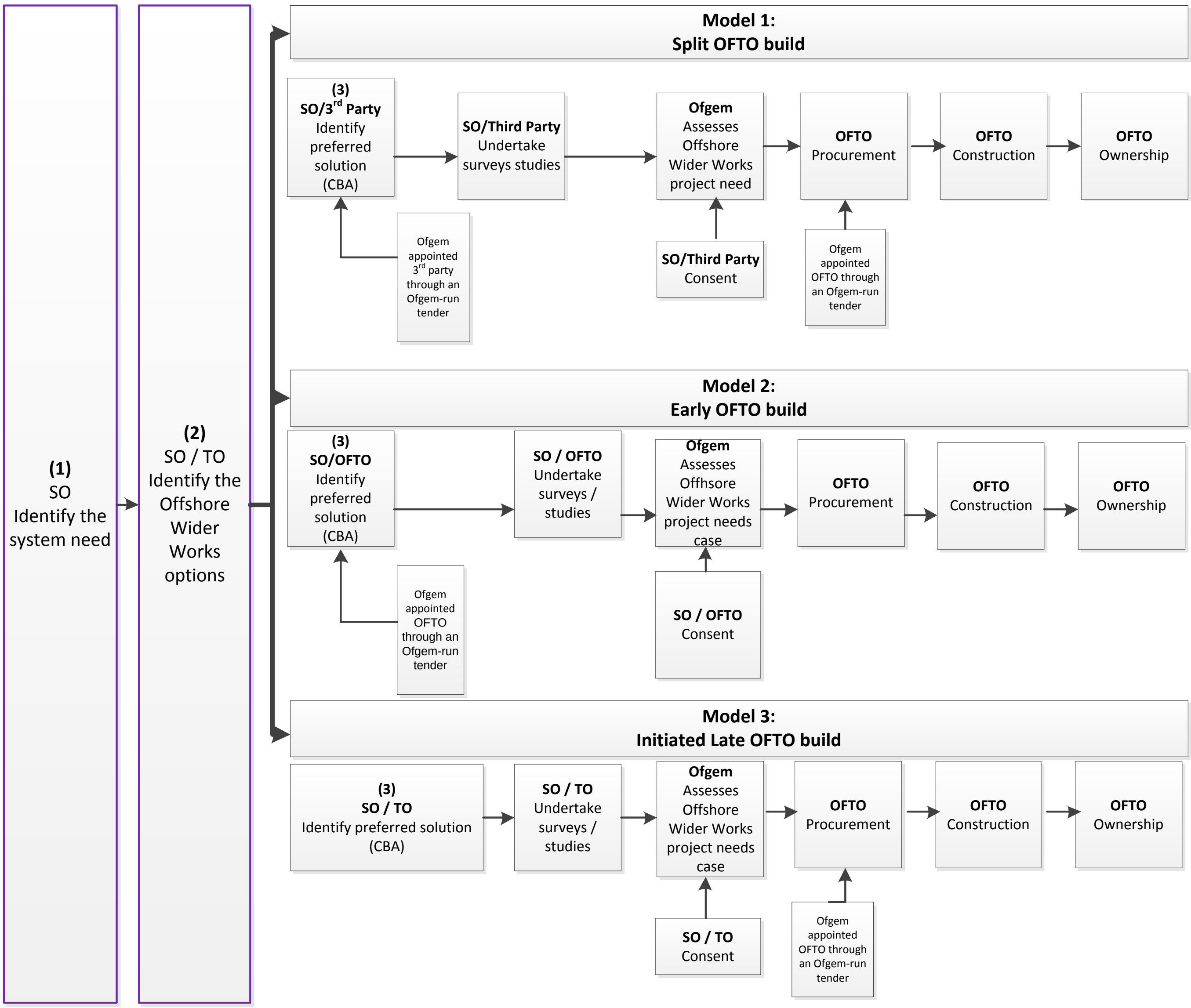
5.37 **Model 2: Early OFTO Build**

a. Under this model the OFTO would undertake the design work, consenting, procurement and delivery of the transmission assets work programme, as well as being responsible for the operation, maintenance and decommissioning of the assets. Ofgem would appoint an OFTO through an Ofgem-run tender either before, or during, the early stages of the preliminary works. The successful bidder would be selected based on its plans, capabilities and relevant experience, as well as its proposed fixed and indicative costs.
b. The early OFTO build tender would be held on the basis of a high-level specification for the transmission assets, including associated preliminary works.
c. The OFTO would complete all preliminary works associated with the assets, including securing consents. As part of these works, the OFTO would work with the ESO and relevant TOs to ensure that the assets it would be developing would form part of a coherent network design that meets both the high level specification and network requirements.
d. At the invitation to tender (ITT) stage, bidders would be likely to bid their desired Tender Revenue Stream (TRS) based on a combination of fixed and indicative costs, with indicative costs possibly subject to a capped contingency or a sharing mechanism. The specifics of the bid requirement would be defined in the ITT document for each tender. Ofgem also envisage that the OFTO’s revenue would be linked to the completion of key deliverables and outputs.
e. As the OFTO approached the completion of the preliminary works and ahead of construction, Ofgem would assess the Needs Case for the investment in more detail to determine whether proceeding to construction would be in the interests of consumers. If so, Ofgem would then engage with the OFTO to finalise its TRS to construct, own and operate the assets. As part of this process Ofgem would seek to fix the terms within the OFTO’s licence (such as its TRS) which would have been set on an indicative basis during the ITT and licence award stage.

5.38 **Model 3: Initiated OFTO Build**

a. In the December 2012 consultation, Ofgem set out an option where onshore TOs could submit proposals for funding to undertake the preliminary works for Non Developer Associated Offshore Wider Works, followed by a late OFTO build tender to identify an OFTO to construct, own and operate the assets.
b. Ofgem stated that the TO would work with the ESO to identify the Offshore Wider Works opportunity and develop a corresponding Needs Case. There is the possibility that such a route would use a mechanism in the onshore TO licences (which would need to be introduced complementary to the onshore price control processes) to allow the TO to recover its cost of preliminary works for a project should Ofgem deem the works to be in the interests of consumers.
c. The TO would complete the preliminary works and produce the outputs needed to run a late OFTO build tender. The TO would be expected to engage stakeholders and coordinate with other relevant parties, including affected developers and the ESO. It would also be expected to support the subsequent late OFTO build tender if it goes ahead, undertaking activities such as populating the data room, responding to queries from bidders, and contributing to a smooth and timely tender process. The late OFTO build tender would be similar to the approach set out in our May 2012 consultation on Developer Associated late OFTO build, with adaptations if necessary to reflect that the preliminary works were undertaken by a TO rather than a developer.

Offshore Wider Works – Non Developer Associated process flow diagram



This diagram shows the overall Offshore Wider Works Non Developer – Associated process. The text in each box corresponds to the descriptions of the stages explained in general process above.

6

ESO process for High Voltage Management

Overview of the High Voltage Management Process

6.1 The objective of the process is to ensure economical and efficient options for high voltage management will be available when required. This Electricity System Operator (ESO) led process is designed to identify high voltage issues in the transmission system, the causes, requirements and the preferred options to solve these issues. The process is designed to work with all expected option providers including Transmission Owners (TO), Distribution Network Owners (DNO) and Reactive Power Service Providers. Figure 6. 1 gives an overview of the High Voltage Management Process.

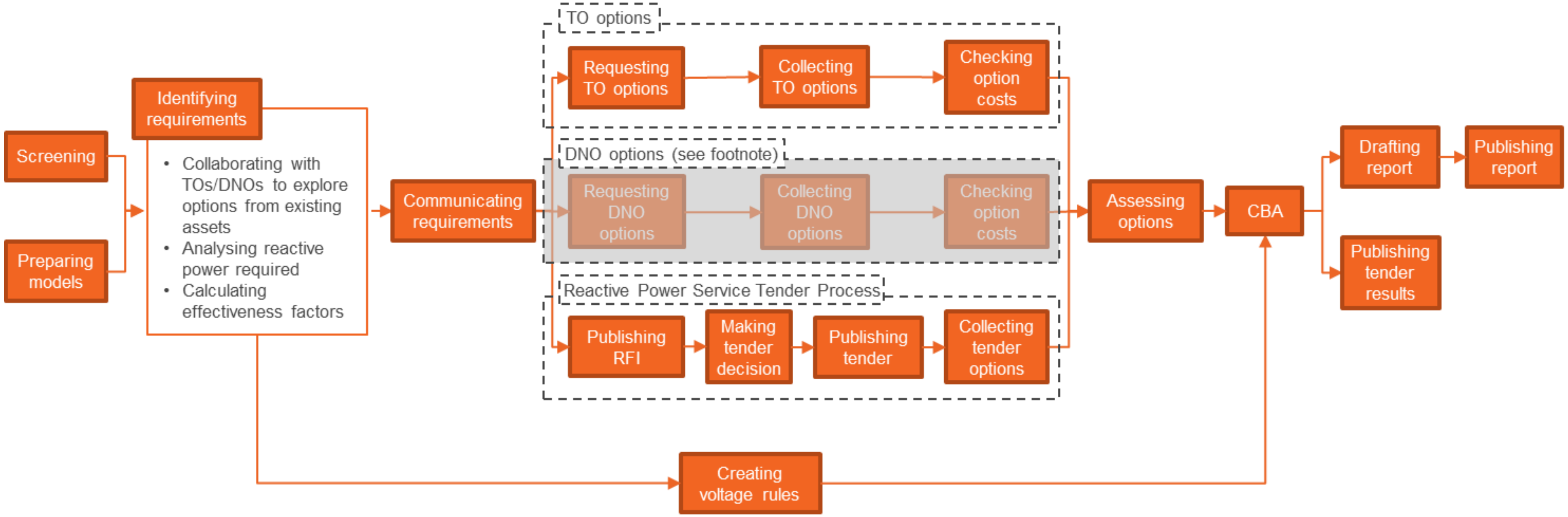


Figure 6. 1Overview of the High Voltage Management Process[28]

[28] In the long term when a regulatory funding mechanism for DNO options is agreed, it is expected that DNO options will follow a similar route as TO options, but presently a suitable regulatory funding mechanism is not in place for the DNO options. Until a suitable funding mechanism is established it is expected that the DNO options will be paid via the Balancing Service Contract; hence DNO options will follow the same route as Reactive Power Service options in the short term.

Programme

6.2 The ESO carries out the screening process annually. The ESO anticipates to carry out the screening process after the technical analysis for boundary capabilities, which typically concludes around October.

6.3 Detailed assessment of any prioritised regions will be initiated on demand and as agreed between the ESO and the relevant TOs and DNOs.

6.4 Timeline of the detailed assessment of any prioritised regions will vary depending on the complexity and the size of requirements. The ESO will agree the timeline with the relevant TOs and DNOs involved.

Roles and responsibilities

System Operator

6.5 National Grid Electricity System Operator (ESO) leads the High Voltage Management Process. ESO shall be responsible for:

- Plan develop and operate the NETS in accordance with the SQSS
- Selecting and prioritising regions by screening
- Preparing network models for analysis
- Collaborating with TOs and DNOs to identify requirements
- Communicating requirements to providers
- Collecting options from providers
- Assessing options
- Collaborating with DSO[29] to carry out the technical assessment of distribution-connected options
- Recommending options based on cost-benefit analysis
- Communicating process conclusions to providers
- Procuring Reactive Power Services via Balancing Service Contract
- Publishing the High Voltage Management Process Report

Transmission Owners

6.6 Transmission Owners (TO) shall be responsible for:

- Plan and develop their networks in accordance with the SQSS
- Providing feedback on regions which they think should be prioritised in this process
- Preparing network models for analysis
- Collaborating with ESO to explore options from existing assets of their networks for analysis
- Collaborating with ESO to identify requirements
- Supporting the assessment of options which connect to their networks if required
- Proposing options using the System Requirement Form - Voltage

Distribution Network Owners

6.7 Distribution Network Owners (DNO) shall be responsible for:

- Compliance of their networks
- Preparing network models for analysis
- Collaborating with ESO to explore options from existing assets of their networks for analysis

DNOs shall also be responsible for the following, while the relevant DSO does not yet exist:

- Collaborating with ESO to identify requirements
- Supporting the calculation of effectiveness factors for their networks
- Collaborating with ESO to carry out the technical assessment of distribution-connected options which connect to their networks

DNOs will be invited to respond to any Request for Information and/or participate in any Tender Process. They can propose options which meet requirements set out by ESO via the Tender Process[30].

[29] Where a relevant DSO function does not yet exist, it is expected that the relevant DNO will take responsibility.

[30] In the long term when a regulatory funding mechanism for DNO options is agreed, it is expected that DNO options will follow a similar route as TO options, but presently a suitable regulatory funding mechanism is not in place for the DNO options.

Reactive Power Service Providers

6.8 Reactive Power Service Providers will be invited to respond to any Request for Information and/or participate in any Tender Process. They can propose options which meet requirements set out by ESO via the Tender Process.

Principle of assessment for high voltage issues related investment

6.9 The ESO plans, develops and operates the transmission system so that voltage levels stay within the normal operating ranges defined within the National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS)[31]. The specific voltage limits used in planning and operating the transmission system can be found in chapter 6 of the NETS SQSS.

6.10 To ensure the ESO can plan the system to operate securely and safely while managing voltages both economically and efficiently, a Network Options Assessment (NOA) style methodology is proposed. This will facilitate the assessment of options to develop the electricity networks to meet future voltage control requirements.

6.11 In terms of voltage control requirement, an immediate need is being seen for high voltage control, so the initial focus will purely be on managing high voltages. This will be an expansion to the existing NOA methodology which primarily focuses on thermal and voltage issues that are typically seen when power transfer across the network is high. This is normally assessed at peak demand periods. High voltage issues are typically encountered during period of light system loading or minimum demand.

6.12 Other voltage control concerns are present but to avoid increased complexity and delay they are not being addressed in this methodology. As the NOA methodology continues to evolve, the ESO will expand the methodology to cover further voltage control concerns in the future.

6.13 High voltage issues are typically confined to relatively small areas and voltage control solutions are usually ineffective over long distances so the ESO will apply a regional approach to the assessment.

6.14 The ESO uses cost-benefit analysis (CBA) to provide investment recommendations. Cost-benefit analysis compares the cost of a proposed solution and the monetised benefits over the project's life to inform the investment recommendation. To effectively meet the future voltage control requirement, the ESO also considers system operability when recommendations are made. The two primary factors that will drive an ESO recommendation are:

a. **Monetised benefits**, when monetised benefits are higher than the forecast solution cost. This implies investing in the proposed solution will provide a more economical and efficient way to manage voltages in the long term when compared to the ESO paying for reactive power services in real-time via the Balancing Mechanism (BM).

   <u>Justification based on monetised benefits</u>

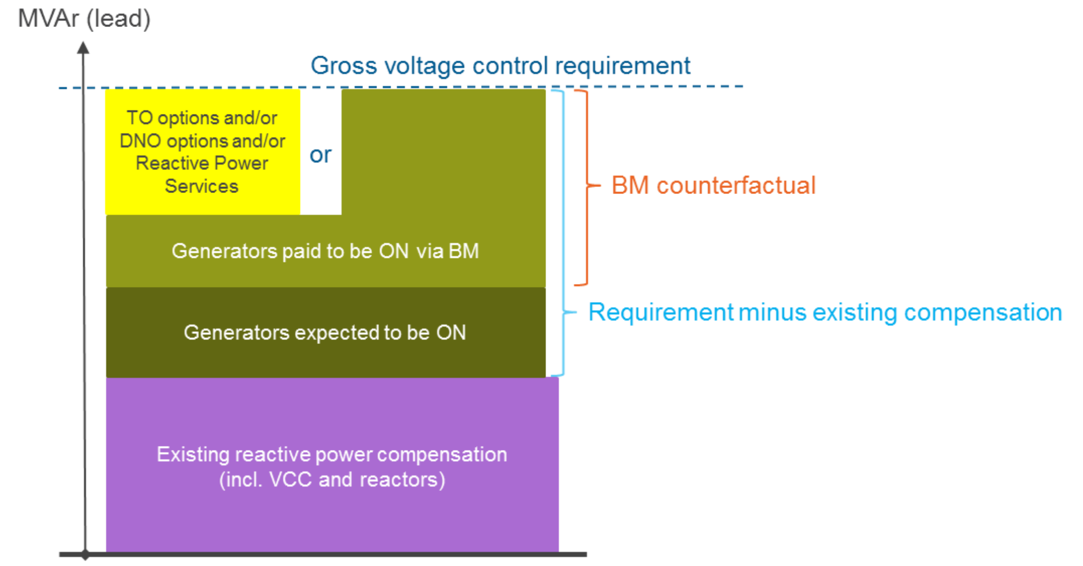
   The monetised benefits are the cost saving achieved by investing in a proposed solution compared to using existing services such as Obligatory Reactive Power Services (ORPS)[32]. The ESO currently relies heavily on the reactive power capabilities of generators for managing voltage. The ESO hopes to see savings on constraint cost and, in some cases, utilisation cost as well. To estimate this saving, the ESO forecasts the constraint and utilisation costs they will pay for accessing and using the ORPS via the BM.

   Constraint cost refers to the bid and offer price the ESO pays (for the MW) to get a generator onto the system to provide reactive power support, together with another generator reducing its generation or turned off elsewhere on the system to maintain the balance of supply and demand. Utilisation cost refers to the payment the ESO makes (for the MVAr) to generators for using their reactive power capabilities, the more being used the higher the cost.

[31] Transmission Licence Standard Conditions C17: Transmission system security standard and quality of service, Paragraph 1

[32] The Obligatory Reactive Power Service (ORPS) is the provision of varying reactive power output. At any given output generators may be requested to produce or absorb reactive power to help manage system voltages close to its point of connection. All generators covered by the requirements of the Grid Code are required to have the capability to provide reactive power.

The aim here is to find the solutions which deliver additional benefits to the consumers, in the form of net savings. This is achieved by replacing services which will need to be procured via the BM with lower cost proposed options. Figure 6. 2 shows how proposed options replace services from the BM to meet the voltage control requirement. The ESO uses cost-benefit analysis (CBA) to compare forecast investment costs and monetised benefits over the solution's life to inform this investment recommendation.



In this case, the ESO expects the remaining requirement (i.e. gross requirement minus existing compensation) can be satisfied by generators with mandatory service agreements (MSA) (or other contractual obligations).

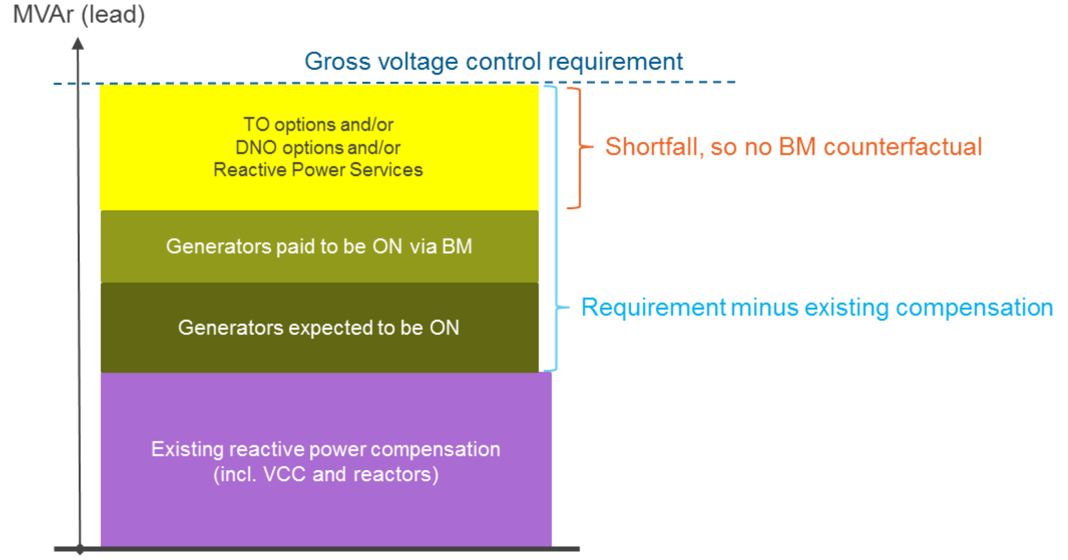
Investment recommendations made in this case focuses on the monetised benefits. It is possible for the ESO to secure Reactive Power Services in real-time via the BM and ORPS. The aim is to explore potential solutions which provide overall savings to the consumers.

Figure 6. 2 Proposed options replacing services from the BM to meet voltage control requirement

b. **Operational security requirement**, when there are insufficient means to provide reactive power to contain high voltages and securely operate the network. This implies the forecast reactive power required in the future is higher than is forecast to be available via the BM or other means.

   <u>Justification based on security and operability</u>

   Given the rapid changes in generation and demand backgrounds, there may be times in the future where there will be insufficient reactive power compensation or services available to meet the voltage control requirements within a region. If such situation is observed in the analysis, the ESO will then focus on verifying the credibility of the assumptions leading to such a situation. If deemed credible, the most cost effective solution to resolve the situation will be pursued. Figure 6. 3 shows how proposed options provide the reactive power needed to meet voltage control requirement as sufficient services cannot be procured from the BM.



In this case, the ESO expects to have insufficient reactive power capability available and cannot satisfy the requirement by using generators with MSAs.

Investment recommendations made in this case focus on the operational security requirement. There is a risk that the system will be inoperable in real-time if nothing is available to provide the extra reactive power required to control the high voltages.

In order to meet the requirement (indicated as shortfall in the diagram), this may also mean that if generators who have MSAs wish to propose a Reactive Power Service option, the ESO can only consider it if they are offering reactive power capability above their mandatory requirements in the tender process.

Figure 6. 3 Proposed options providing the reactive power needed to meet voltage control requirement as sufficient services cannot be procured from the BM

6.15 Investment recommendations will be based on the above mentioned two primary factors. As a general principle, if there are several options which meet the requirements and satisfy either of the two primary factors, the CBA chooses the most economical and efficient options. This is described in more detail in the section "Cost-benefit analysis".

The High Voltage Management process

Regional approach – determining the most economical and efficient solution for High Voltage Management Process

6.16 Voltage is a localised property of the system which means that requirements vary from one region to another. The voltage control requirements are determined by the configuration of the local network and the nature of generation and demand in that region. Since reactive power, unlike real power, cannot be sent across long distances due to the reactance of the transmission network, voltage control is most effective when applied close to the problem. Voltage issues can therefore be grouped into regions and assessment of each region conducted separately. The High Voltage Management Process looks into the reactive power required for high voltage control on a regional basis.

Screening process – selecting and prioritising regions

6.17 The ESO uses a screening process to help identify and prioritise the region(s) which should be further explored through detailed power system and cost-benefit analysis. This should bring consumers the best value by ensuring the secure, economical and efficient development focuses on challenging regions first. The screening process considers four main factors which are in line with the NOA assessment principles – cost, network change,likelihood and lead time.

- Cost: The focus is on the historic spend in each region to procure Reactive Power Services for managing high voltages. A high historic spend in a region suggests heavy reliance on the BM and ORPS, which suggests potential benefits of conducting an assessment to evaluate the best options to provide future reactive support in the region.
- Network change: This refers to any significant changes of the system in the future, including new generation (including embedded generation), major generator closures, commissioning of new cables etc. Regions which do not associate with a high historic spend, but which are set to see some significant changes that contribute to an increasing need for reactive support should be assessed.
- Likelihood: This is an assessment about how likely the above two factors will materialise. For example, if the high historic spend was due to a routine maintenance outage, it will be considered more likely than spend due to a long outage caused by a fault.
- Lead time: This refers to the typical lead time to deliver an option in the region of interest. For example, if a compliance concern will arise soon after any options can be sourced to meet the requirements, there is an urgency to assess the region.

6.18 The ESO will request feedback from the TOs as to which region(s) they believe should be assessed. This includes any compliance concerns in their networks.

6.19 The ESO will discuss any compliance concerns raised by the TOs and agree a plan to assess these concerns. The discussion will consider when the compliance issue may materialise and the lead time of potential options to resolve the issue.

6.20 The above mentioned four factors, together with the TOs' feedback, will be used to help determine the region(s), as well as the backgrounds and conditions the ESO will consider in the assessment. For example, conditions which are associated with high historic spend and are expected to persist or grow in severity will be analysed. The ESO will apply these conditions to future backgrounds which show similar characteristics to the system when those high historic spends arose.

Creating network models for analysis

6.21 The ESO will use the GB system planning models produced in accordance with the SO-TO Code (STC) for this High Voltage Management Process. Future backgrounds based on Future Energy Scenarios (FES) and system conditions considered appropriate in accordance with the NETS SQSS will be applied to the models for assessment.

6.22 TOs and DNOs will support the ESO in preparing the models for analysis.

Identifying requirement

Collaborating with TOs/DNOs to explore options from existing assets

6.23 The ESO collaborates with Network Owners, TOs and DNOs, to ensure a consistent methodology is applied when it comes to plan and develop the transmission system. TOs are obliged by their transmission license to plan and develop their transmission network in accordance with the NETS SQSS. DNOs have a key role in enabling a whole system approach to address some of the future requirements in the transmission system while maintaining compliance of their distribution system.

6.24 The ESO shares the initial view of areas of priority with the relevant TOs and DNOs. The ESO aims to ensure consistent methodology, models, backgrounds and sensitivities are considered across all analysis. TOs and DNOs provide feedback about their networks in the relevant areas. The feedback will help the ESO to optimise existing assets prior to analysing the system needs in those areas in details. To ensure the transmission system is planned and developed in an economical and efficient manner, the ESO should only proceed with new requirements once existing network assets are optimised.

6.25 Where available, the ESO engages with the system operator function of the distribution companies.

Analysing the size of the reactive power requirement

6.26 The ESO identifies the reactive power required to control voltage based on system analysis results. The requirement varies depending on the future backgrounds and system conditions. It is not practical to fully analyse all combinations of backgrounds and conditions. Hence, the ESO selects snapshots using historic records assisted by data mining techniques and engineering judgement to represent a fair number of variations of backgrounds and conditions. The same four factors, which were considered during the screening stage (i.e. cost, network change, likelihood and lead time), are used to help with the selection.

6.27 The ESO collaborates with the TOs and DNOs to identify the reactive power required for the transmission networks.

6.28 The diagram below illustrates how the analysis to identify the reactive power required may be structured. The example shows variation in demand assumptions. The selection of the specific study backgrounds and system conditions, which set out the analysis, however depends on the characteristics of the region of interest.

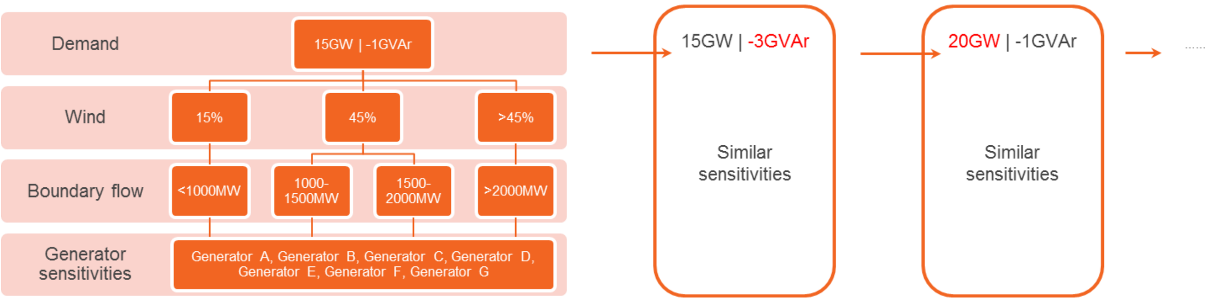


Figure 6. 4 Example of backgrounds and conditions considered for analysis

6.29 The reactive power required depends on what the ESO expects the system will need in the future to maintain voltages within the NETS SQSS limits. To determine the reactive power required for any region of the network the following steps are applied:

1. Set up analysis with selected credible backgrounds and system conditions
2. Analyse to check if the NETS SQSS requirement can be met with existing reactive power compensation and generators which are predicted to run
3. If the NETS SQSS requirement can be met, note the generators running in the region of interest and move on to the next sensitivity analysis
4. If the NETS SQSS requirement cannot be met

a. Consider using different combinations of generators in the region of interest which are accessible via the BM
    i. Simulate constraint (bid and offer) actions until the voltage control requirement is satisfied
    ii. Note the generators running in the region of interest
b. Consider suitable transmission solutions
    i. Simulate investment in new transmission assets until the voltage control requirement is satisfied
    ii. Note the size of new reactive power compensation plant(s) required and the location they are connected at. This is used to define the reactive power required for the region
c. Continue to the next analysis

6.30 The recorded generators running under each analysis will be used to formulate the voltage rules. This is described in more detail in the section *"Creating voltage rules"*.

Calculating effectiveness factors

6.31 To allow a fair comparison to be made for all potential options, effectiveness factors are used when the ESO assesses options. The effectiveness of an option is directly linked to its point of connection. It changes the amount of reactive power required to meet the requirement. This will change the total volume expected to be invested or procured. For example, if a unit A was assessed to be 50% effective and unit B 100% effective, to resolve the same issue the system would need to use twice as much reactive power from unit A than B. Unit A would need to be significantly cheaper to have the same benefits.

6.32 Effectiveness changes with certain system conditions, for example with certain outages. The ESO calculates effectiveness factors for each point of connection against the same (set of) background to ensure all providers are treated equally.

6.33 The below examples are all aimed to be illustrative, and provides approximations of potential differences in effectiveness. This will change when specific technical assessment for each region is completed. Provider A in green, Provider B in red.

Example 1

Provider A and B are connected at the same site. The site is run solid. The two different providers have different reactive ranges.

The providers would likely have the same effectiveness score.

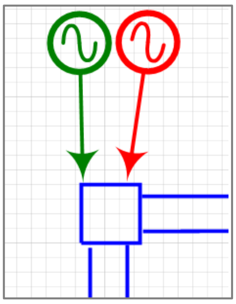


Figure 6. 5

Example 2

Provider A and B are connected at different, adjacent, sites, but sites that are geographically close together.

The providers would likely have similar effectiveness score.

Note: Distance in the diagram is indicative only.

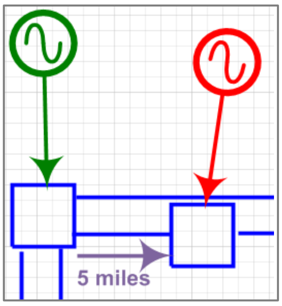


Figure 6. 6

Example 3

Provider A and B are connected at different, adjacent, sites, but sites that are geographically far apart.

The providers would likely have different effectiveness score.

Note: Distance in the diagram is indicative only.

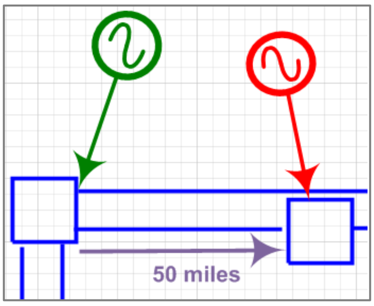


Figure 6. 7

Example 4

Provider A and B are connected at different voltage levels, but the same GSP. Provider B is connected at 132kV in the DNO network.

The ESO expects the services close to the source of the issue has higher effectiveness.

If, for example, the source of the issue is at the transmission network, then Provider B that is connected at a 132kV voltage level is likely to be less effective than Provider A. Providers connected at lower voltages than 132kV, in this example, would be expected to be even less effective.

Alternatively, if, for example, the source of the issue is at the distribution network[33], then Provider B is likely to be as effective (or more effective in some cases) than Provider A.

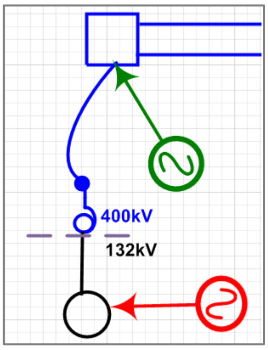


Figure 6. 8

Example 5

The reactive power required is set specifically for a defined region. The region has been defined based on potential effectiveness.

Provider A is inside the defined region and Provider B is outside the defined region.

Providers outside the region are assessed as only being ineffective at resolving the issue.

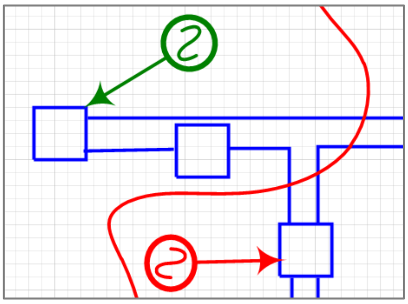


Figure 6. 9

6.34 Many factors affect the effectiveness of an option, such as where and how it will connect to the network. Effectiveness factors are relative to a reference point in the network. The ESO chooses reference point(s) in the network based on where it is most effective to implement reactive power compensation to meet the requirement of the region of interest. Then through system analysis the ESO calculates the effectiveness of various available transmission-level connection points with respect to the reference point(s).

[33] The Power Potential Project, which aims to create a new reactive power market for distributed energy resources (DERs), will provide further insights into effectiveness of options connected to the distribution network. The ESO will learn from the Project and continuously improve their understanding of effectiveness.

6.35 For distribution-level connection points, the ESO works with the relevant DNOs to calculate the effectiveness factors. Where available, the ESO engages with the system operator function of the distribution companies.

6.36 For example, system analysis suggests it is most effective to implement reactive power compensation at substation Y. It also suggests the system needs reactive power compensation to absorb 100MVAr at substation Y to meet the system requirement. The ESO will therefore tell the providers that "the equivalent of reactive power compensation to absorb 100MVAr at substation Y" is needed. Next, the ESO calculates the effectiveness for options connecting at substation Z. Substation Y is the reference point. The ESO models reactive power compensation to absorb 100MVAr at substation Z and test it with selected backgrounds and conditions. Analysis results show that (on average) implementing a reactive power compensation to absorb 100MVAr at substation Z reduces the compensation required at substation Y from 100MVAr to 25MVAr. The ESO can then approximate the effectiveness for any options connecting at substation Z as (100-25)/100 = 0.75 with respect to the reference point.

Communicating requirements

6.37 The reactive power required to control voltage will be communicated to relevant parties in the form of "equivalent reactive power compensation to absorb X MVAr at location Y".

6.38 The ESO also provides information on the effectiveness of reactive power compensation or services installed away from location Y. This information will be presented in a heatmap. All effectiveness factors are relative to the same reference point(s). This is most likely to be the same reference point(s) stated in the requirement i.e. "location Y" for consistency.

6.39 The ESO will provide the same information on requirement to all potential option providers. Such information will be provided to the TOs using the System Requirement Form – Voltage (SRF-V). This uses a similar format and structure as the SRF used in the current NOA for network boundary flow. The same information will be provided to the DNOs and Reactive Power Service Providers via the Tender Process.

6.40 For the avoidance of doubt, this does not imply other information which the TOs and DNOs currently have access to in accordance with the likes of SO-TO Code (STC) or Connection and Use of System Code (CUSC) for network planning purposes will be provided to all parties due to confidentiality reasons.

Requesting & collecting options

6.41 The ESO will invite potential solution providers including TOs, DNOs and Reactive Power Service Providers to propose options to meet the reactive power for voltage control requirements.

6.42 Any parties interested to have their options considered by the ESO should respond to the invitation to propose options.

6.43 The TOs should respond using the SRF-V while the DNOs and Reactive Power Service Providers should respond via the Tender Process.

6.44 For the avoidance of doubt, all options received will be assessed against each other using the same criteria. The different submission process reflects the difference in funding mechanisms - TO options will be recovered via the present transmission regulatory framework, while DNO and Reactive Power Service options will be paid via the Balancing Service Contract. The ESO considers and assesses all options in the same CBA. See the section "Cost-benefit analysis" for more details.

6.45 The option collection process for each party is as follows:

Branch 1 – TO options

The exchange of option information between the ESO and the TOs will be by means of the System Requirement Form – Voltage (SRF-V). The outline of the SRF-V structure is shown in Table 6. 1.

Table 6. 1 Outline of System Requirement Form - Voltage

SRF-V Part	Section title	Details
A	Requirement	Information on requirement in SRF-V Part A will be the same as the information published as part of the Request for Information (see Branch 3 for more details).
B	TO proposed options	TOs provide the information on their proposed options.
C	Outage requirement	TOs provide the expected outages required to connect new assets associated with their proposed options.
D	Not applicable	N/A
E	Option costs	TOs provide the costs on their proposed options. Information should include, but is not limited to: Capital cost, annual breakdown of cost, operation & maintenance cost, WACC etc.
F	Publication information	TOs specify the information which they give consent to the ESO to publish. The ESO will request consent from the TOs to publish the same level of information consistent with the way information from a DNO option or a Reactive Power Service option will be published when the Tender Process concludes.

6.46 System requirements are sent to the TOs using SRF-V Part A. Unless stated otherwise, this also acts as the prompt to the TOs to propose options.

6.47 TOs are expected to submit their options to the ESO using SRF-V Part B, Part C and Part E. All costs supplied in the submission should be in current financial year base prices. SRF-V Part D is not used in the High Voltage Management Process.

6.48 The SO reviews the costs that the TOs submit with their options and check that they are reasonable. The SO checks the costs that the TOs submit against a range of costs for plant and equipment that the ESO has gained from recent experience. If any costs are outside of the range, the SO discusses the costs with the relevant TO. If, following discussions the ESO still believes that the costs are outside of the expected range and will unduly affect the CBA, the ESO can omit the option from the CBA.

Branch 2 – DNO options

6.49 In the long term when a regulatory funding mechanism for DNO options is agreed, it is expected that DNO options will follow a similar route as TO options, but presently a suitable regulatory funding mechanism is not in place for the DNO options. Until a suitable funding mechanism is established it is expected that the DNO options will be paid via the Balancing Service Contract; hence DNO options will follow the same route as Reactive Power Service options in the short term. Therefore, DNOs who wish to propose options should respond via the Tender Process.

Branch 3 – Reactive Power Service Tender Process

6.50 The ESO publishes the requirements to inform potential Reactive Power Service Providers as part of a Request for Information (RFI). This includes the technical requirements which a Reactive Power Service must meet to participate in the Tender Process. The ESO uses the RFI to gather information about options that could relieve the high voltage issues. In general, the ESO would like to understand the following before a decision to tender is made:

- The ability of the market to provide Reactive Power Service options as alternatives to Network Owner options to control high voltage
- The level of interest to provide a Reactive Power Service to meet the identified long-term needs

- The likelihood of achieving a more economical and efficient overall solution by considering a wider range of options
- The delivery timescale of market-based options
- Preferred contract options

6.51 The RFI information pack will include an indicative timeline for the Tender Process, including when a decision to tender will be made.

6.52 The ESO decides whether to tender based on the information received from the RFI. The decision will be published alongside a final timeline for the Tender Process.

6.53 If a decision is made to tender, the ESO will publish the Tender Process information pack with selected contract options. The ESO expects the requirements published in the Tender Process information pack to be the same as those published in the RFI information pack, and the assessment methodology to be consistent with this methodology document. Any exception will be stated in the Tender Process information pack. Details in the Tender Process information pack supersede the details from the RFI.

6.54 Any parties interested to have their Reactive Power Service options considered by the ESO should respond to the Tender Process. Any responses should use the proforma published as part of the Tender Process information pack.

Creating voltage rules

6.55 Voltage rules are created to indicate the minimum number of generators required to meet voltage control requirements in a region. The voltage rules are formulated using system analysis results. This approach loosely simulates the close-to-real-time process for voltage management. Studies against generator sensitivities, as illustrated in the previous section, are carried out for each selected set of conditions to help determine the minimum number of generators required and define the voltage rules. Since generators differ in sizes, each generator will be assigned a size coefficient to reflect their different reactive power capabilities.

6.56 The ESO uses these voltage rules with the constraint cost modelling tool to simulate year-round system operation. The number of bid and offer actions required to maintain system voltages within the NETS SQSS can then be estimated.

6.57 The constraint cost saving for each proposed option can then be estimated. Representing those variations of study backgrounds and system conditions in the CBA is crucial to the credibility of the estimated constraint cost saving. These backgrounds and conditions will be built into the voltage rules and hence considered in the CBA.

Assessing options

6.58 When the ESO receives options from potential providers (TOs, DNOs, Reactive Power Service Providers), these options need to be modelled and analysed so their actual impact to system voltages can be understood. The assessment often includes many options; and it may be necessary to group a few options together to create the solution which can meet the system requirement in a region. It may also be more economical and efficient to group options from various providers together i.e. combining TO, DNO and Reactive Power Service options, to meet the requirement. It is however inefficient and impractical to always assess – model and analyse - all possible groups of options. Therefore, the assessment process set out below is used to keep the modelling and analysis at a practical level.

6.59 The ESO will assess the options selected in the CBA and ensure those options satisfy the service and technical requirements before the final recommendation is made and the Tender Process concludes.

6.60 The ESO intends to analyse as many options and combinations as practically possible. Only if the number of options available means there are too many possible combinations, the ESO will perform a pre-assessment selection. For the avoidance of doubt, this pre-assessment selection is designed to keep the assessment practical for the High Voltage Management

Process; the overarching principle of finding the most economical and efficient solution still applies.

Pre-assessment (applicable when a high number of options are available)

6.61 The ESO bases the pre-assessment selection on two main factors - effectiveness and cost. The pre-assessment aims at reducing the number of options to keep the number of possible combinations practical.

6.62 The ESO first calculates the equivalent effective MVAr compensation each option provides with respect to the same (set of) reference point(s) (effective MVAr). The relevant effectiveness factor is applied to each option according to its point of connection and its effective MVAr is calculated.

6.63 The ESO then considers the cost of the option. As the process considers options from TOs, DNOs and Reactive Power Service Providers, it is expected that the costs of options will cover a range of service terms. Hence the cost per year of each option is used for comparison. See the section "Cost-benefit analysis" for more details on calculating the cost per year for each option.

6.64 The ESO considers the effective MVAr and cost per year of each option. A cost-effectiveness factor will be calculated for each option in the format £/effective MVAr per year.

6.65 Options are then ranked according to their cost-effectiveness factors. The options with greatest cost-effectiveness will be selected for the CBA.

Cost-benefit analysis

6.66 The cost-benefit analysis, as mentioned in previous sections, provides investment recommendation based on two primary factors – monetised benefits or security and operability. As a general principle, if there are several options which meet the requirement and satisfy either of the two primary factors, the CBA chooses the most economical and efficient options.

How does the ESO estimate constraint cost?

To estimate constraint cost, the ESO uses the same constraint cost modelling tool as NOA – Poyry's BID3. This provides consistency with NOA. The ESO uses BID3 to model a European economic dispatch and a GB constrained dispatch (re-dispatch). More information on BID3 can be found in section 2 of the NOA Methodology.

The tool is used to work out constraint (bid and offer) actions required to maintain voltage compliance against future simulated scenarios. The criteria applied to evaluate constraint actions for high voltage control is different to those used by NOA to determine network boundary flow related constraint actions. The criteria is linked to the minimum number of local generators required on the system to maintain voltage compliance by means of voltage rules. This requirement is informed by analysis on credible future backgrounds and system conditions.

BID3 applies voltage rules to simulate the bid and offer actions required to maintain voltage compliance. The focus here is to represent the reactive power capability of generators while keeping the MW cost as low as possible, therefore the cost to move a plant to its minimum stable generation position is priced. Where applicable, footroom requirements will be considered.

The high-level process for estimating constraint cost using BID3 is outlined below.

1. Run an economic market dispatch
   The BID3 model is dispatched for each future energy scenario.
2. Run a network constrained re-dispatch
   Apply the forecast boundary capabilities and constraints based on the latest FES database and NOA investment recommendations. Re-dispatch the network as per the previous step.
3. Extract hourly data for pertinent plants for the voltage rules
   For the areas under consideration and according to the voltage rules determined from the technical studies, extract the hourly data relevant for all options under consideration.

4. Examine the hourly data to see what is required to fulfil the rules
   For each option, examine in turn the hourly data to see whether the rules are complied with or what actions need to be taken for them to be complied with. This then creates a list of actions for each option which need to be taken for every hour for the validity of the rules and for each scenario.
5. Cost the actions required based on bid and offer prices and minimum stable generation
   The cost of the bid and offer actions is taken from the assumptions made within the BID3 model and the actions required to meet the voltage rules costed.

How does the ESO estimate utilisation cost?

Utilisation cost will be dependent on a range of factors, such as the following:

- Rate: The ESO applies the current ORPS rate[34] or the contracted rate where applicable.
- Point of connection: Utilisation varies depending on where an option is and the network topology at its point of connection.
- Service duration: Duration an option will be active i.e. how often the ESO expects an option will be required to control high voltages.
- Equipment used: The different equipment used to provide the Reactive Power Services affects how often and how long an option will be used.
- System needs: For example, whether the reactive power capability is required pre-fault and/or post-fault will impact how often and how long an option will be used.

It is impractical to calculate utilisation based on fixed point system analysis as utilisation varies with system conditions. To fairly recognise the utilisation cost, the ESO estimates it based on how the BM units or newly proposed options are anticipated to be used.

6.67 The CBA considers various factors, including but not limited to:

- System requirements for controlling high voltages
- Point of connection of option
- Effectiveness
- Assessment period
- MVAr capability provided by proposed option
- Flexibility to offer only part of the MVAr capability of proposed option
- Earliest-in-service date (EISD)
- Cost

6.68 In previous sections, system requirements, point of connection and effectiveness have already been discussed in detail.

6.69 Assessment period is defined as the years over which the future voltage control requirements are reasonably clear and certain. This should be the same as the period for which the Tender Process requests for options.

6.70 Options may provide different MVAr capability in each year.

6.71 In some cases, a provider who can offer only part of the MVAr capability of its proposed option may help achieve an overall solution of lower cost to consumers. The ESO considers this flexibility when they select options to form the most economical and efficient solution(s).

6.72 EISD refers to the earliest date when an option will be available to provide the required reactive power.

6.73 The cost to provide the service can be split into capital costs and operational costs. All costs submitted should be in current financial year base prices. Table 6. 2 below provides the

[34] The rate which the ESO pays BM providers for utilisation in £/MVArh under the default payment mechanism. The utilisation payment is updated monthly in line with market indicators as set out in Schedule 3 of the Connection and Use of System Code (CUSC).

various element of costs to be included as the capital cost and operational cost in TO options, DNO options and Reactive Power Service options.

Table 6. 2 Details of capital and operational costs for each type of providers

Option providers	Capital cost	Operational cost
TOs	• Cost of the new assets associated with an option • WACC to be applied to regulated assets	• Maintenance • System access • Other ongoing operational cost associated to the option
DNOs	• In the short term while the DNO options will be paid via the Balancing Service Contract, the cost of DNO options should be submitted via the Tender Process and in the same format as required by the Tender Process.	
Reactive Power Service Providers	•	• As per contract, which may include: ○ Availability payment ○ Utilisation payment

6.74 The capital cost is any infrastructure cost that will be incurred by a Network Owner (TOs or DNOs). The ESO applies the weighted average cost of capital (WACC) to any network infrastructure costs that will be incurred due to an option. The ESO will seek this information directly from the relevant Network Owner(s). The capital cost should be submitted as spend profile, which indicates when the capital will be spent.

Table 6. 3 Example of spend profile

Year	2019/20	2020/21	2021/22
Cost £m	5	10	8

6.75 The operational cost should include any maintenance, system access and other ongoing costs. The operational cost will be applied for each year that the option is utilised. The operational cost submitted may vary by year.

6.76 The benefits that each option provides will be discounted at the social time preference rate as laid out in the Treasury Green Book[35]. This process results in the present value (PV) of each cost and benefit.

6.77 The ESO first calculates the equivalent effective MVAr compensation each option provides with respect to the same (set of) reference point(s) (effective MVAr). The relevant effectiveness factor to each option is applied according to its point of connection and its effective MVAr is calculated.

6.78 The ESO then calculates the cost of providing an effective MVAr for each option. The operational cost per effective MVAr will be calculated as the PV operational cost per year divided by the quantity of effective MVArs provided.

$$PV\ Op.Cost\ per\ eff.MVAr = \frac{PV\ Operational\ cost\ per\ year}{eff.MVArs}$$

6.79 The capital cost will be calculated as the PV capital cost divided by the product of the quantity of effective MVArs and the number of service years. Service years is defined as time that the option will be available and cost-effective within the assessment period.

$$PV\ Capital\ Cost\ per\ eff.MVAr = \frac{PV\ Capital\ Cost}{eff.MVArs \times Service\ Years}$$

[35] https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent

6.80 The sum of the operational and capital costs per effective MVAr will be the cost per effective MVAr for the option.

$$PV\ Cost\ per\ eff.MVAr = PV\ Op.Cost\ per\ eff.MVAr + PV\ Capital\ Cost\ per\ eff.MVAr$$

6.81 The goal of the CBA is to find the most economic and efficient solution(s) to the problem for the GB consumer. An optimisation will be carried out across all years within the assessment period simultaneously to find the cheapest solution(s). This is to take into account the capital cost of each option which is independent of the number of years that the option is considered optimum.

6.82 With the cost per effective MVAr calculated, the bids will be stacked, with the lowest cost per effective MVAr at the top, and the highest at the bottom. In general, bids will be selected from the top first until the system requirement for effective MVArs has been met. The stack order may be altered if more cost-effective combinations become apparent.

6.83 The ESO conducts this process for every year individually within the assessment period.

6.84 A provider may submit an optimal bid in one year, but this does not guarantee the bid will be optimal in subsequent years if lower cost options are available. The lowest cost solution(s) over the entire assessment period will be chosen. Note that in some cases this may result in a more flexible or smaller option that is more expensive per MVAr to be chosen.

6.85 Within each yearly stack, the ESO forecasts the cost of procuring the system voltage need through the BM. This will be done by modelling future GB electricity markets using the latest future energy scenarios and assessing within each settlement period which generators will be able to provide a solution to voltage issues. The BM costs for procuring the need will be again converted into a cost per effective MVAr which will be placed within each yearly stack to compete against the submitted options.

6.86 An example of the stacks and the selection of winning bids (highlighted green) is shown below in Table 6. 4. Please note that the costs shown are not reflective of any forecast, they have simply been chosen for demonstration purposes.

Table 6. 4 Example of selection of options based on cost per effective MVAr to achieve a solution with most economical and efficient total cost

System need: 200MVAr				
Provider name	**Flexible?**	**Provider effective capability (MVAr)**	**Cost per effective MVAr (cost/MVAr)**	**Cost**
Provider 1	Yes	50	10	500
Provider 2	Yes	100	14	1400
Provider 3	No	25	15	375
Provider 5	Yes	50 (25 procured)	18	450
Provider 4	No	50	17	
BM	Yes	200	22	
Provider 6	Yes	100	30	

6.87 The total cost in Table 6. 4 is 500+1400+375+450=2725. Note that Provider 5 is selected ahead of Provider 4 even though Provider 5 has a higher cost per MVAr. This is because Provider 5 is more flexible and allows the system need to be met exactly. Using Provider 4 would result in the system need being exceeded by 25MVAr and result in a higher total cost (500 + 1400 + 375 + 850 = 3125). There is a cheaper (although not the cheapest) solution where Provider 4 is selected ahead of Providers 3 and Provider 5. This solution has a cost of 500 + 1400 + 850 = 2750 and exactly 200MVAr is procured. In some cases, the system operator may allow excess MVAr to be procured if this would result in a lower cost for the consumer and pose no operational issues.

6.88 The CBA recommends the options which should be taken forward. Given the size of the investments and the short lead times, these recommendations are a single lifetime decision. This means that when an option is recommended, that recommendation persists until the asset or service contract expires. This is different to the normal annual NOA least-worst regret (LWR) recommendations which are reviewed annually. Where a recommendation is marginal, the decision may be to reassess at a later date when there is greater certainty of the need. This is only possible where the EISD of the option is ahead of the need and so the option can be delayed.

Process conclusion

6.89 Based on the results of the CBA, the ESO recommends the solution which should be taken forward. The recommended solution could consist of only TO option(s), only DNO option(s), only Reactive Power Service option(s), or any combination of these three types of options. If the CBA concludes that none of the options proposed in the process provides benefits against forecast BM cost to control high voltages, the ESO may accept no Network Owner options and/or Reactive Power Service options.

6.90 If the recommended solution consists of TO option(s), the ESO will write to the relevant TO(s) to inform them of the recommendation to support an investment case.

6.91 If the recommended solution consists of Reactive Power Service option(s), the ESO will contact the relevant provider(s) after publishing the tender outcome and proceed with procuring the selected option(s) using the Balancing Service Contract.

6.92 If DNO option(s) are recommended, in the short term while the DNO options will be paid via the Balancing Service Contract, the ESO will proceed with the DNO option(s) in the same way as with any Reactive Power Service options.

Tender outcome

6.93 Tender outcome will be announced as soon as reasonably practical once the analysis and other relevant verification and approval process conclude. Tender outcome will be published on the ESO website.

Regional report

6.94 A regional report on the High Voltage Management Process will be published after all the analysis and tender activities conclude. The report includes driver, requirement, effectiveness and recommended solutions. It is expected that most of the information will have been made available at the various stages in the process already by the time the report is published.

6.95 The report will not include sensitive information unless agreement has been established with the information owner or is permitted by legislations or code.

6.96 On publication the report will be placed on the ESO website as a PDF document.

A

Appendix A NOA study matrix

Assumption/Condition		Comments
Generation and Demand Scenarios	Two Degrees	Technical and economic assessment of the reinforcement options; sensitivity studies where appropriate
	Community Renewables	Economic assessment of the reinforcement options and technical assessment as required; sensitivity studies where appropriate
	Consumer Evolution	Economic assessment of the reinforcement options and technical assessment as required; sensitivity studies where appropriate
	Steady Progression	Economic assessment of the reinforcement options and technical assessment as required; sensitivity studies where appropriate
Seasonal Boundary Capability	Winter Peak	Technical and economic assessment of the reinforcement options
	Spring/Autumn	Technical and economic assessment of the reinforcement options. Technical assessment of boundary capabilities can be calculated based on agreed scaling factors from winter peak capabilities which are validated against benchmarked results. Benchmarking is subject to availability of the model and agreement on generation despatch
	Summer	Technical and economic assessment of the reinforcement options. Technical assessment of boundary capabilities can be calculated based on agreed scaling factors from winter peak capabilities which are validated against benchmarked results. Benchmarking is subject to availability of the model and agreement on generation despatch
Boundary Capability Study Type	Voltage Compliance	
	Thermal	
Contingencies	N-1-1	
	N-1	
	N-D	
Network Reinforcements	Build reinforcements	
	Reduced-build reinforcements	Assessment of reduced-build reinforcement options

Assumption/Condition		Comments
	Operational reinforcements	Assessment of operational options
Study Years	Year 1	Assessment of alternative reinforcement options subject to availability
	Year 2	Assessment of alternative reinforcement options subject to availability
	Year 3	Assessment of alternative reinforcement options subject to availability
	Year 4	Assessment of build and alternative reinforcements options excluding those are subject to Ofgem agreement
	Year 5	Assessment of build and alternative reinforcements options excluding those are subject to Ofgem agreement
	Year 7	Assessment of build and alternative reinforcements options excluding those are subject to Ofgem agreement
	Year 10	Assessment of build and alternative reinforcements options excluding those are subject to Ofgem agreement

B

Appendix B Validation checks of seasonal scaling factors

Introduction

The ESO's NOA report analysis uses a constraint cost model. In 2015/16, this was ELSI. ELSI applies scaling factors to the winter peak capabilities which are from technical studies. These give the seasonal boundary capabilities. We derived the scaling factors using a set of assumptions. The purpose of these validation checks was to verify the assumptions and if necessary recommend changes.

Background

We use a technical model to study the transmission network and find boundary limit based on winter peak loadings in the Two Degrees scenario. Boundary limits are dominated by thermal and voltage constraints that result from the loss of the worst fault on the boundary. Ambient temperature affects thermal limits so warmer seasons warm conductors more. This in turn depresses ratings and hence boundary capabilities. Voltage limits are not directly related to seasonal effects hence we considered them to stay constant across seasons. ELSI works by applying a set of scaling factors to the winter peak figure. The scaling factors change the winter values to represent warmer seasons and also for outages. Outages depend on the number of circuits on a boundary – the fewer circuits there are the greater the impact of a single outage. Once we have applied the scaling factor to get the boundary figure, the lowest of the thermal or voltage figures is the active constraint value in each season.

How we did the checks

We selected three boundaries and used the technical modelling tool to check the thermal and voltage limits for the spring/autumn and summer seasons. We also studied the effects of outages on these boundary limits. We turned the boundary limits from the technical studies into factors and compared them against the factors in ELSI. We chose boundaries B7. B7a and B8 because they had both thermal and voltage limits. They also demonstrated a variety of numbers of circuits crossing the boundaries. The table below shows the results:

Boundary Constraint	Season	Boundary	Existing ELSI Scaling	Studied Scaling	Relative Difference (ELSI vs Studied)
Thermal	**Spring/ Autumn**	Avg. B7,B7a,B8	90%	80%	**↓-10%**
	Summer	Avg. B7,B7a,B8	80%	80%	**≈0%**
	Summer Outage	B7	60%	72%	**↑+12%**
		B7a	66%	72%	**↑+6%**
		B8	71%	69%	**↓-2%**
Voltage	**Spring/ Autumn/ Summer/ Summer outage**	Avg. B7,B7a,B8	100%	90%	**↓-10%**

Conclusion

There is a spread in the differences between the existing ELSI scaling factor and the technical model studies. In the study for summer thermal intact was accurate while summer thermal outage had a 12 per cent difference. We concluded that different generation and demand patterns reduced the voltage limits. Scaling the voltage limit will give slightly pessimistic results in the studies but will help to highlight issues that we can investigate further.

Seasons and outages are just two of the factors that affect boundary capabilities. Wider system flows and how generation is located along the length of a boundary affects the distribution of loading of circuits across a boundary. This in turn affects how quickly a circuit overloads and hence when the boundary reaches its limit. The nearer a concentration of generators is to the overloaded circuit that sets the boundary limit, the sooner the boundary bites. As a result, there will always be approximations in any methodology that does not use technical study tools at every stage of the process.

Recommendations

The validation checks led to recommendations to change the scaling factors in the economic model which the table below summarises:

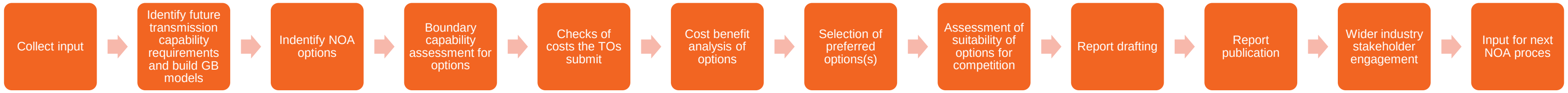
	Existing ELSI scaling factor	Recommended change
Spring autumn scaling thermal	90%	85%
Summer scaling thermal	80%	No change
Summer outage scaling thermal	80% x (n-3)/ (n-2)	70%
Voltage scaling	100%	90%

'n' is the number of circuits crossing the boundary.

The ESO implemented these revised seasonal scaling factors for the second NOA report analysis and will be prepared to amend them following future reviews. However, if the seasonal ratings are directly studied, then they may be used in place of the scaling factors

C

Appendix C NOA process flow diagram



This diagram shows the overall NOA process. The process headings can also be found in the main methodology.

D

Appendix D System requirements form templates

SRF Part	Changes	SOFI Content?	
Part A – Boundary requirement and Capability	Reduced	Yes	ESO sends out a requirement level for each boundary which triggers the TO's response in providing options to meet the capability requirement level for that boundary. The form includes the BID3 unconstrained boundary transfers. Each boundary will have its own Part A.
Part B – TO Proposed Options	Reduced	Yes	TO responds with an option that may partially or wholly meet the requirements set out by Part A. Each option will have its own Part B
Part C – Outage Requirements	Reduced	Yes	TO responds with outage requirements for that option. Each option will have its own row in Part C.
Part D – Studied Option combinations	New	Yes	TO and ESO supply how the options' capabilities have been studied to ensure that the ESO accurately and faithfully reproduces the options' order and capabilities in the economic analysis. Part D is a spreadsheet with some automation to generate flowcharts.
Part E – Options' Costs	Expanded	Yes	TOs supply asset and cost information to allow the ESO to proceed with 'cost reasonableness' (See Appendix E). Each option will have its own Part E, but only if it has featured in Part D.
Part F – Publication Information	Reduced	No	TOs supply names and descriptions of options for publication use. Each option will have its own row in Part E but only if it has featured in Part D.

SOFI stands for System Operator Functions Information.

SRF Part A: Boundary Requirement and Capability

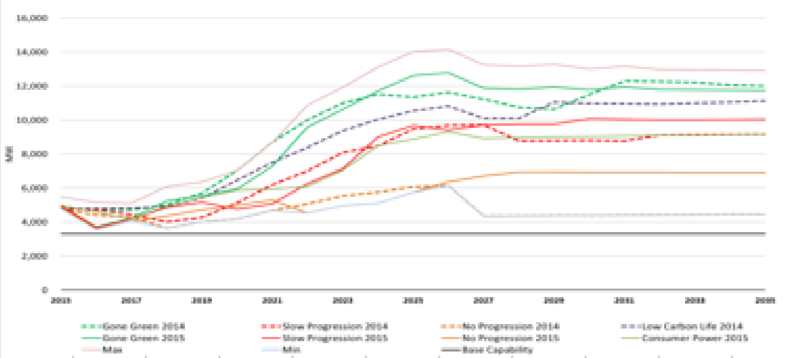
Part A: SO Requirement

For more information please see the information provided separately by the boundary studies.

Requirement preparer:	*ESO to fill in the SO PSE studying this boundary*
Passed TaF Date:	*ESO to fill in the TO engineer whom this was passed to and when*
Boundary under Analysis:	*ESO to fill in which boundary this relates to*

Winter Peak Boundary Required Transfer Summary:

Year 1 Winter Peak Base Capability (from previous year):	*Year 1 winter peak base capability for this boundary as a guidance for the TO*



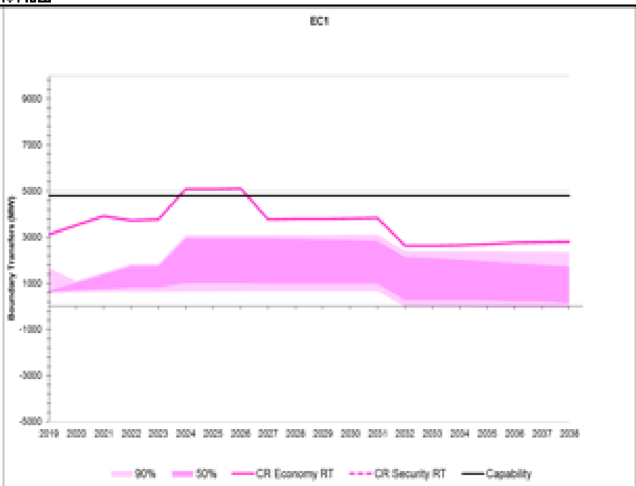
	Economy	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Winter Peak Required Transfers in accordance with NETS SQSS Chapter 4 Economy Background (in MW)	Two Degrees	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
	Community Renewables	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
	Consumer Evolution	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
	Steady Progression	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW

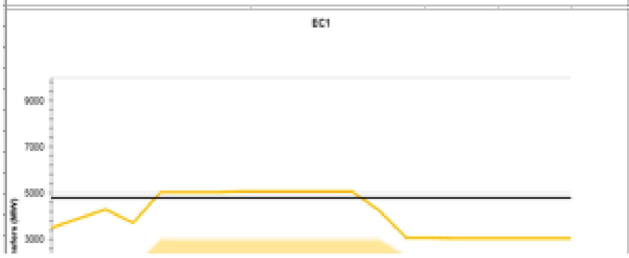
	Security	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Winter Peak Required Transfers in accordance with NETS SQSS Chapter 4 Security Background (in MW)	Two Degrees	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
	Community Renewables	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
	Consumer Evolution	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
	Steady Progression	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW

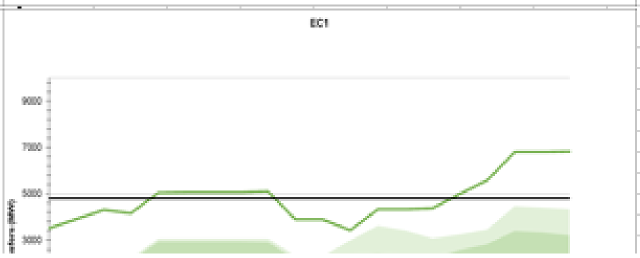
Unconstrained Boundary Flows

The section below details the unconstrained flows across the boundary. The 90th percentile and 50th percentile ranges have been highlighted for each scenario and this has been compared to the required transfer in accordance with the SQSS. The top four charts illustrate the FES18 unconstrained flows and the four charts below them show this year's FES19 unconstrained flows.

2018 Flows







SRF Part B: TO Proposed Options

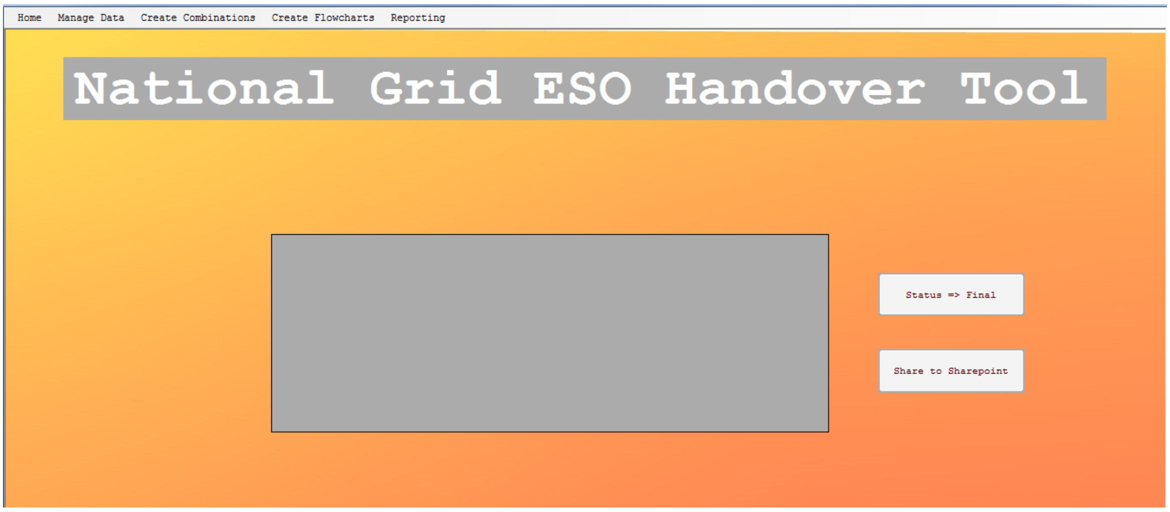
Part B: TO Proposed Options	
TO Ref number:	*Option reference number if available*
Option Name:	*Insert the name of the proposed reinforcement.*
Who initiated the option? *	*State who initiated the option, that is TO or ESO.*
Target boundary or boundaries:	*List the boundary or boundaries that the option is to reinforce*
Status: Same/Changed/New	*Select 'Same' if the option has been proposed before, or 'new' if is a new option.* ***If it has been proposed before but since modified please select 'changed' and note the modifications here along with background reasons for the change.***
Stage that option is at:	*Use the descriptions listed in the NOA methodology for the stage that the project is at. These are Project not started, Scoping, Optioneering and consenting started, Design/ development and consenting, Planning / consenting, Consents approved.*
Physical Description:	*Provide a description of the physical nature of the reinforcement sufficient to allow power system modelling. Please thoroughly list the all assets and works by type, number (for cable and OHL provide the length in km), voltage level and size. Please highlight any* ***new assets in bold.***
Diagram:	*Put a before and after diagram of how the configuration will look including circuits and substation layouts. This applies to the options which will introduce variations to the network topology and equipment layouts. For refurbishment options (e.g. Hotwiring, replacement of equipment), please put one diagram and highlight the alterations.*
What problem does the reinforcement solve?:	*Describe how the proposed solution will increase capability for each boundary in turn with reference to Part A or information supplied by boundary studier*
Lead engineer:	*TO contact name in case of queries*
Scheme or TORI number: *	*Scheme Numbers (England and Wales TO only) or TORI number (Scottish TOs).*
Environmental Impacts:	Brief overview of any environmental implications that progressing this option may
EISD:	*Year*
EISD change background if applicable:	*If the EISD has changed, please provide background reasons that have led to the change.*
Enabling works:	*State if the option also forms enabling works for a customer connection and if so which one(s).*
Enabling works' requirement nature:	*If the option* ***is*** *enabling works, please state the nature of the requirement that the works are intended to manage e.g. thermal, stability, fault level, voltage.*

SRF Part C: Outage Requirements

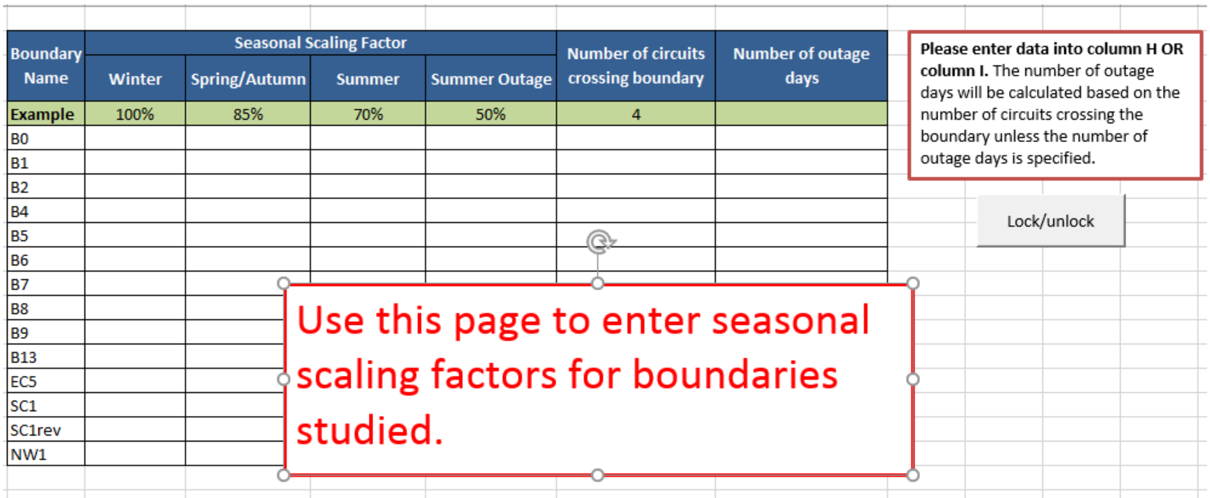
Part C: Outage Requirements							
TO Option Reference Number	EISD	Year of Outage	Circuits Out	Outage Duration (weeks)	Restrictions in Sequence of Works	Lead Engineer	Additional Comments
TO Reference number. Must be same as Part B.	*EISD*	*Year*	*Circuits Out*	*weeks*	*State whether the works must be done in a certain order*	*TO contact name in case of queries*	*If required, additional comments for ESO PSE*
		Year	*Circuits Out*	*weeks*			
		Year	*Circuits Out*	*weeks*			
TO Reference number. Must be same as Part B.	*EISD*	*Year*	*Circuits Out*	*weeks*	*State whether the works must be done in a certain order*	*TO contact name in case of queries*	*If required, additional comments for ESO PSE*
		Year	*Circuits Out*	*weeks*			
		Year	*Circuits Out*	*weeks*			
TO Reference number. Must be same as Part B.	*EISD*	*Year*	*Circuits Out*	*weeks*	*State whether the works must be done in a certain order*	*TO contact name in case of queries*	*If required, additional comments for ESO PSE*
		Year	*Circuits Out*	*weeks*			
		Year	*Circuits Out*	*weeks*			

SRF Part D: Studied Option Combinations

The information contained in the SRF Part D submission will be processed through the use of National Grid ESO Handover Tool. This application will be the means by which the TOs will submit their boundary capability by reinforcements and scenarios directly to National Grid ESO.



Seasonal scaling factors can be submitted using the following template. Otherwise, actual seasonal boundary capabilities can also be submitted using the ESO Handover Tool above.



Boundary Name	Seasonal Scaling Factor				Number of circuits crossing boundary	Number of outage days
	Winter	Spring/Autumn	Summer	Summer Outage		
Example	100%	85%	70%	50%	4	
B0						
B1						
B2						
B4						
B5						
B6						
B7						
B8						
B9						
B13						
EC5						
SC1						
SC1rev						
NW1						

SRF Part E: Option Costs

Part E: Option's Costs		
TO Reference Number	TO Reference number. Must be same as Part B.	
WACC Used	% value used for Weighted Average Cost of Capital	
Option Breakdown of Costs		
Total Cost of New Assets/Works	**Cost in £m**	*The total cost of completely new transmission assets or complete replacement of transmission assets.*
Total Cost of New Assets/Works which are also separable	**Cost in £m**	*The portion of the above cost where the ownership between these assets and other (existing) assets can be clearly delineated.*
Total Cost of other Assets/Works	**Cost in £m**	*The remaining cost of any assets/works which are not completely new transmission assets or complete replacement of transmission assets.*
Total Cost of Consents	**Cost in £m**	*Total cost of consents for this option*
Total Cost of Option	**Cost in £m**	*Total cost of option (This should be the sum of 'New Assets/Works', 'other assets/works' and 'consents'*

Delay Costs

The costs table covers for when a project is delayed/cancelled now and delayed/cancelled after one year's work and resources have been put into it. The assumption is that costs after one year's progress will be the same for subsequent years apart from discounting. Use the 'reconsenting' row if the project will cost to restore consents. If there is no submisison in this table, the ESO will assume it can cancel or delay projects at nil cost.

	2020/21	2021/22 (if it were to be proceeded in 2020/21)	Additional Comments
Cost of Demobilisation (£m)	*cost of bringing a project in flight to a stop*	*cost of bringing a project in flight to a stop*	*If you wish, insert additional comments if you'd like to further explain the impacts of demobilising a project if it is already in flight.*
Ongoing delay costs (£m)	*cost of continuing to delay a demobilised project*	*cost of continuing to delay a demobilised project*	*If you wish, insert additional comments if you'd like to further explain the impacts of delaying a demobilised project.*
Cost of Remobilisation (£m)	*cost of proceeding a demobilised project*	*cost of proceeding a demobilised project*	*If you wish, insert additional comments if you'd like to further explain the impacts of remobilising this project if it were to be demobilised.*
Costs of Reconsenting (£m)	*cost of new consents*	*cost of new consents*	*If you wish, insert additional comments if you'd like to further explain the impacts on consents if this project were to be delayed by any number of years.*
Other Delay Costs (£m)	*additional costs to delaying the option*	*additional costs to delaying the option*	*Please state the reason for the additional delay costs. If you wish, insert additional comments if you'd like to further explain the impacts on delaying this project.*
Cancellation (£m)	*cost of permanently cancelling the project*	*cost of permanently cancelling the project*	*If you wish, insert additional comments if you'd like to further explain the impacts of cancelling an option if it is already in flight.*
Total 1 year Cost to Delay (£m)	*total cost of delaying the project for 1 year*	*total cost of delaying the project for 1 year*	*If you wish, insert additional comments if you'd like to further explain the impacts of delaying a project for 1 year*

SRF Part F: Publication Information

TO Reference Number	NOA Code	NOA Publication Name	NOA Publication Description	Additional Comments
TO Reference number. Must be same as Part B.	*Filled in by ESO*	*The name of the option to be used in the NOA publication*	*The description of this option to be used in the publication*	*If required, additional comments for ESO PSE*

E

Appendix E Process for checking NOA option cost reasonableness

This appendix describes the process that the ESO uses to assess the NOA option cost data that the TOs provide as an input to the NOA economic process.

Figure E1 shows the process map for the cost reasonableness checking process.

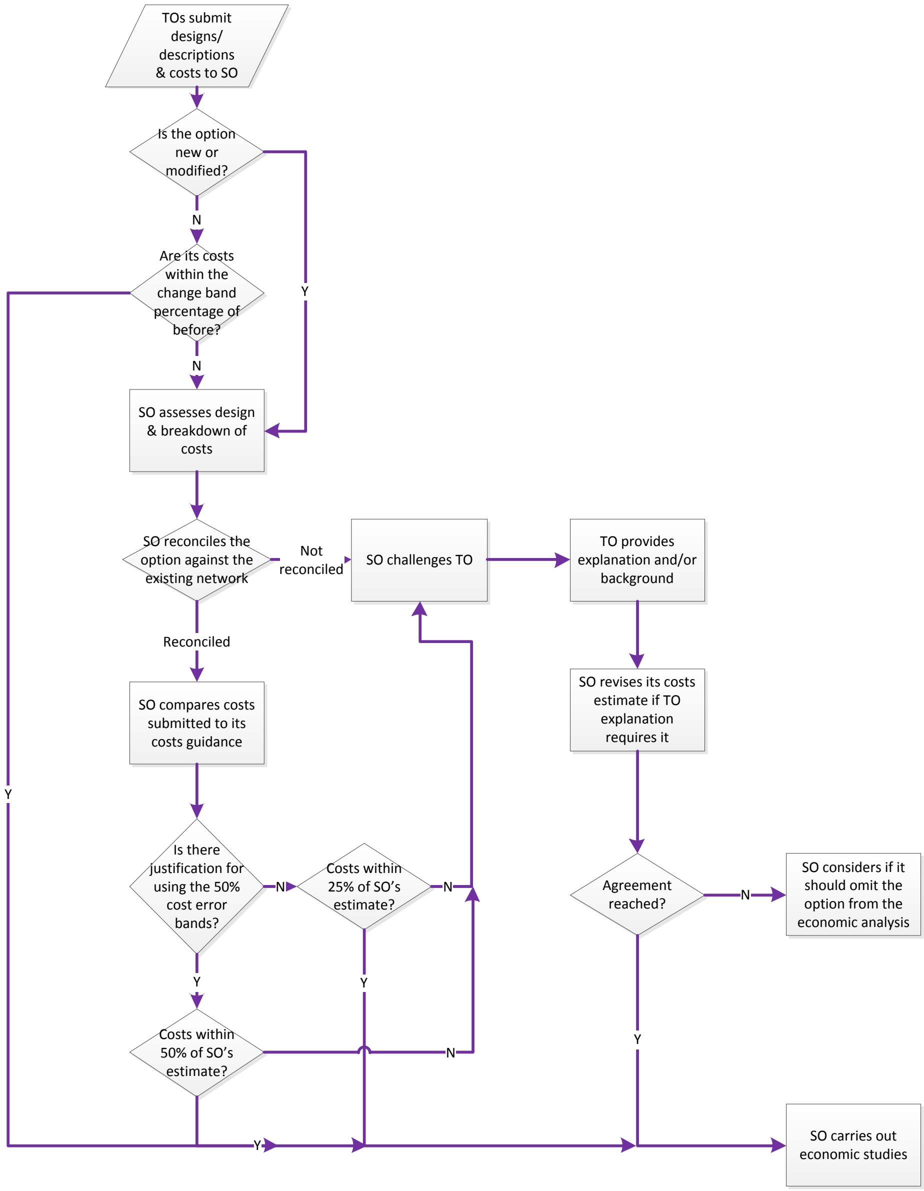


Figure E1: cost reasonableness checking process map

The input to the process is the costs that the TOs submit for their NOA options. The output of the process is the TOs' cost submissions to be deemed valid and act as an input into the NOA economic process. The TOs may modify their costs following discussions with the ESO as part of this process. If following discussions, the ESO still believes that the costs are outside of their expected range and will consequently unduly affect the economic analysis, the ESO may omit the option from the economic analysis.

The ESO maintains independent cost guidelines which are derived from RIIO unit costs and external public domain market intelligence. The ESO compares the costs of different options from a TO against previous years (allowing for inflation) and against its cost guidelines.

The headings below match the stages in the process map.

TOs submit designs/descriptions & costs to ESO

Having received the cost information from the TOs via the SRFs, the ESO gathers the information together. The ESO needs the following data, which it captures from the SRF:

- Detailed technical breakdown of the reinforcement option
- Cost data for the option.

Is the option new or modified?

Are its costs within the change band percentage of before?

The first step is for the ESO to identify which options should proceed through the cost reasonableness process. New or modified options always proceed through the cost reasonableness process. Options where the designs are unmodified from previous years' submissions may be exempt from the remainder of the cost reasonable process as they will have had their costs approved through previous years' ESO cost checks, provided any increase in costs falls within an expected range. If the costs submitted for the current year are within the change band of +/- 5% of previous submissions, then the cost checking process for such an option ends here. Options where the costs have changed outside this range, or options which have modified or new designs, proceed through the process as normal.

ESO assesses design & breakdown of costs

The aim of this step is for the ESO to understand the option, how it is intended to deliver the benefit, the component parts of the option and its benefit. The ESO takes the technical breakdown descriptions of the option and builds up its understanding of the reinforcement option:

- The ESO checks the descriptive text with any diagrams that the TO has provided Note that some options will not need diagrams, for instance if they are about thermal upgrades or other overhead line work.
- The ESO checks that equipment requirements are consistent and complete. For instance, where a new circuit is proposed, does the SRF explain how it will connect to the existing transmission system – are new bays proposed and how many, or will it reuse existing bays? Is equipment already installed mentioned separately from equipment that will be installed in the future?
- The ESO checks environmental factors. For example, whether the option needs consents and whether the option is in a mainly urban or rural setting.

It is expected that the level of disaggregation of options included in the SRF and the cost accuracy will vary with the level of maturity of the option, with those options which have been developed over a few years being broken down into more detailed aggregate components with more accurately estimated costs than those in the initial stages of conception where design and costs are more approximate.

The ESO reconciles the option against the existing network

Having built up its understanding of the option, the ESO checks the existing part of the network that the option affects. This is to identify any parts of the option that might have been omitted and which may affect the cost estimate. The ESO notes any omissions or discrepancies in the SRF and seeks clarification from the TO. An example might be that the SRF describes using a spare bay so the ESO checks the latest system diagram to check for the bay's details. For an explanation of the remainder of the process, go to the **ESO challenges TO** stage on the process map.

ESO compares costs submitted to range of costs in its guidelines

The ESO performs two tests for each option at this stage as applicable.

1) Having developed its understanding of the option, the ESO compares the option's costs against the ESO's cost guidelines.
2) The ESO identifies similar options within a TO's portfolio and checks the cost consistency between them. For instance, where two options replace the conductors of circuits of the same voltage level, the ESO calculates the unit costs based on the TO's submission and checks how similar they are.

Is there justification for using the 50% cost error bands?

Some aspects of options add a lot of uncertainty to the forecast cost of a project and so are allowed a larger cost error. For this reason, the ESO measures against a 50% cost error band for any option affected by the following:

- consents
- new technology with high uncertainty.

Costs within 25% of ESO's estimate?

This step applies to options that involve **no** added justification for the wider cost error bands.

The first stage is for the ESO to compare the TO's submission with its own estimate of costs. If the costs are within 25%, the ESO progresses to the second stage.

The second stage is to check that a TO's costs are consistent with other options' costs across its portfolio. If this is the case, then the ESO sets the option costs as 'agreed' and the costs are used in the economic process.

If the costs are outside of the 25% band and/or the costs are not consistent, the ESO asks the TO for justification. For an explanation of the remainder of the process, go to **ESO challenges TO** stage on the process map.

Costs within 50% of ESO's estimate?

This step applies **only** to options where there is justification for wider cost error bands and is a similar two stage approach.

Firstly, the ESO takes the TO's submission and compares it with its own estimate of costs. If the costs are within the 50%, the ESO progresses to the cost consistency check across a TO portfolio.

If the costs are consistent with other options' costs in the TO portfolio, then the ESO sets the option costs as 'agreed' and the costs are used in the economic process.

If the costs are outside of the 50% band and/or the costs are not consistent, the ESO asks the TO for justification. For an explanation of the remainder of the process, go to the **ESO challenges TO** stage on the process map.

ESO challenges TO

If the ESO finds that an option's costs lie outside of the range that it estimates, it approaches the TO for a more detailed understanding.

TO provides explanation and/or background

In response to the ESO's challenge, the TO provides more information to solve the query. This information might be:

- adding information, for instance including the details of cable section lengths
- correcting assumptions about assets, for instance the amount of plant involved in work on a substation bay
- amending a cost submission due to an error
- the TO challenges the ESO's understanding of costs or option scope.

This is part of an iterative stage.

If the TO provides more information to the ESO, the ESO will revise its cost estimation accordingly to check if the costs are within the 25% bracket or 50% bracket as applicable. If 'yes', then the ESO sets the option costs as 'agreed' and the TO's costs are used in the economic process.

If the TO's response means that the ESO's concerns remain, the ESO reviews its concern, clarifies it and refers it back to the TO.

If after several attempts, the ESO cannot agree to the costs and explanations that the TO is providing, the ESO engineer escalates the matter within ESO management. The ESO management decides whether to include the costs for the option in question at this stage or to omit it from the economic analysis.

ESO revises its costs estimate if TO explanation requires it

The discussion between the ESO and the TO might mean that the ESO has to recalculate its estimate of the costs. The ESO notes the revised costs.

Agreement reached?

The ESO engineer conducting the process passes the ‘agreed’ TO costs for use in the NOA economic process.

General points

The ESO keeps the cost information for all options submitted by each TO and uses them to do consistency checks of options that the same TO submits in future years.

In general, the ESO assumes that the TO cost submissions include the development costs. There might be occasions on which the submissions do not include the development costs in which case the TO and ESO will discuss this further and decide how to proceed with the option for its economic analysis.

F

Appendix F Form of report

The Electricity System Operator (ESO) will produce the main NOA report which will be public and produce appendices where there is confidential information. The confidential appendices will contain full cost details of options and will have very limited circulation that will include Ofgem. Extracts of this report will go to the relevant Transmission Owners (TO). The main NOA report will omit commercially confidential information. We will provide Ofgem with justification for the redactions. This appendix describes the contents and chapters of the report.

Foreword

Contents Page

Executive Summary

The executive summary will include headline information on options listing those that meet SWW criteria.

Chapter 1: Introduction and Aim of the Report

This chapter will describe the aim of the NOA report, provide the reader with clear guidance on its relationship with the Electricity Ten Year Statement (ETYS) and give guidance on how to navigate the NOA report.

Chapter 2: Methodology description and variations

This chapter will describe the assessment methodology used at a high level and refer the reader to the NOA report Methodology statement published on National Grid's public website.

The chapter will also include the definition of and commentary on Major National Electricity Transmission System Reinforcement options. We will include a description of how the ESO treats Strategic Wider Works (SWW).

We expect options to improve boundary capabilities will fall broadly into three categories:

- SWW that have Ofgem approval. The NOA report will refer to these options which will be included in the baseline while presenting no analysis. The Report will justify why these options are treated as such.
- Options that have SWW analysis underway. This analysis and available results will be used in the NOA report.
- Options analysed using the Single Year Regret cost-benefit analysis. This analysis will appear in the NOA report.

Should any options fall outside of these three categories, the chapter will list them with an explanation as to how and why they are treated differently.

Chapter 3: Proposed Options

This chapter is to give an overview of the options that the ESO has assessed. The overview will group options by study region and by their technical type including whether it is build or reduced build More detailed information on each option that will include status will be listed in an appendix. The chapter will include OWW options or record a nil return if there are none. It will also include a commentary on reduced-build or non-transmission ones, where applicable. The chapter will also include a short summary of the boundaries that make up the GB electricity network.

Chapter 4: Investment Recommendations

This chapter will cover the economic benefits of each option. The data will be tabulated and to support the comparison include earliest in service (EISD) and optimum delivery dates. The regret values for the options and combinations of options where the options are critical will be included as an appendix of the report, i.e. those that need a decision to proceed (or otherwise) imminently. Chapter 4 will detail the ESO recommendation whether to proceed with each option. In some instances, there might be a recommendation to proceed with more than one option. Such an instance could be at an early stage when two options are closely ranked but there is uncertainty about key factors for example deliverability.

The chapter will indicate options that are likely to meet the competition criteria. As the competition framework is uncertain due to the necessary legislation not being passed, the chapter will highlight this. The chapter will explain how options meet competition criteria.

The chapter will finish with a summary of the options for the boundary. It will provide:

- Any differences in preferred options between annual NOA reports where the ESO has carried out similar analysis in the past.
- How the scenarios have different requirements and how they affect the options.
- A comparative view of each option's deliverability and how it affects the choice of the preferred options.

The cost band will appear beside options that have a 'Proceed' recommendation.

Chapter 4 will meet the ESO obligation to produce the recommendations for the Network Development Policy for Incremental Wider Works.

Chapter 5: NOA for Interconnectors

This section of the report will introduce the method of analysing GB's potential for interconnectors to other markets and publish the analysis.

Chapter 6: Stakeholder engagement and feedback

To help our understanding of stakeholder views, through the document we will include feedback questions. We will use this feedback to refine the NOA report process and methodology for the next report.

We have used our seminars to continue to talk with stakeholders and have received some interest. Onshore TOs have engaged with us and assisted in developing this NOA report methodology. We want to extend our engagement further and will use our NOA email circulation lists.

Glossary

G

Appendix G Summary of stakeholder feedback

This appendix summarises the views the ESO has on the comments we've received. We would like to thank the organisations for their feedback and contribution.

Area of feedback	Feedback	ESO response
Core NOA process: Competition	How the ESO applies the competition eligibility criteria to bundling and splitting of options. That the existing licence condition does not oblige the ESO to carry out these assessments.	Although the C27 statutory consultation had been carried out in spring 2019, we did not expect a decision until after we would submit the methodology to Ofgem. As a result, we kept the changes that we published for NOA 2018/19 but dropped those proposed for 2019/20.
Core NOA process: Early development of options	The existing licence condition does not oblige the ESO to carry out early development of options. That the TOs have responsibilities to develop the network.	Although the C27 statutory consultation had been carried out in spring 2019, we did not expect a decision until after it would submit the methodology to Ofgem. As a result, we have dropped from the methodology the proposed sections covering early development for 2019/20.
Core NOA process: Use of Earliest In Service Dates (EISD)	Delayed delivery of options is an inherent risk with large projects. The ESO should use critical sensitivities to model the cost effects of options having different delivery dates.	We needs the earliest in service date as a fundamental part of the NOA process. We can accommodate up to five different cost profiles with different EISDs. This allows us to test the effect of different EISDs with appropriate cost profiles. We believe that this is a way forward. For risks that cannot be simply included as data inputs to the CBA, we will work with relevant parties and decide whether and how sensitivity studies can be carried out on a case by case basis. The sensitivity studies will be considered and scrutinised by the NOA Committee.
Core NOA process: NOA report	Simplify the NOA report and use more visuals	We have devised a way to shorten the NOA report by stopping it duplicating the ETYS and thinning out the material in certain chapters.
Core NOA process: Non-compliant boundary reference	The respondent asked us to elaborate on two references to non-compliant in OWW Section 5 of the methodology.	The NOA is an economic assessment of wider boundaries hence the description 'non-compliant' is not relevant. We have amended these two references.
Core NOA process: NOA and Strategic Wider Works	To be more efficient, parties asked if the ESO can use the NOA cost-benefit analysis in the SWW initial needs case instead of the SWW cost-benefit process. While the NOA analysis would be more basic, it is quicker which might be more valuable.	We agree to using the NOA cost-benefit analysis outputs as a basis for SWW initial needs case where appropriate and with the TOs' agreement. This would need to be supplemented by additional analysis for any initial needs case submission. We have updated Section 1 to reflect this.
Core NOA process: Nuclear modelling	The current economic analysis tool does not realistically model the availability and operation of the GB's nuclear fleet, leading to misrepresentation of demand security in Scotland. In order to highlight any future security related reinforcement	The model we use is a deterministic model with a 20-year modelling horizon. To model GB effectively we use year-round availability factors rather than attempting to model 20 years of outages across the country. Any reinforcements that may be required to secure Scotland's demand under low-probability-high-risk network

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	requirements, a more realistic output and outage pattern for these plants must be adopted.	stress periods would be unsuitable to model in detail in NOA.
Core NOA process: Potential transmission solutions	‘Storage’ in table 2.2 might be better described to be used to release constraints in operational timescales. This would replace ‘enhance boundary capabilities’.	We agree with this change and have amended the text in table 2.2.
Core NOA process: Probabilistic studies	The pathfinder project would benefit from a wide group of participants to contribute to the next stage of its development.	We welcome collaboration on the inputs to the tools and process in addition to the results, this will include agreeing the network data to be used in the analysis and ensuring the analysis process runs as effectively and collaboratively as possible. We plan to use the approach to analyse the whole network across the year 1 boundaries and consult on the results and next steps through our Electricity Ten Year Statement (ETYS) publication.
Core NOA process: Probabilistic studies	Supportive of the ESO work in the area of year-round thermal requirements as using a deterministic approach based on winter peak conditions to identify year-round system requirements may result in an overly optimistic or pessimistic view of system needs.	We are pleased you are supportive of our work in the area of year-round thermal requirements. We are further developing our tools and process and hope to provide more information in our ETYS publication in November. We welcome any feedback as we develop our capability in this area and recognise the need to collaborate with our stakeholders to agree the best approach for using the information in our decision-making process in the future.
Core NOA process: Probabilistic studies	Further development is needed for probabilistic approach to make sure network requirements other than DC thermal power flow are considered by the probabilistic approach.	We have plans to expand the probabilistic tools and techniques to allow more complex network modelling in the RIIO-2 period. We also intent to use the approach to model certain system operator actions and alternative reinforcement options such as commercial solutions so that the network conditions can be better represented.
High Voltage Management Process	Pathfinder projects and an ESO-led process for assessment and development of market-based solutions presents a significant opportunity to deliver better value to consumers. It is anticipated that the ESO will actively engage with the industry to further develop market-based solutions.	We’re delighted to know that you appreciate our intention to facilitate consideration of a wider set of solutions to transmission system needs. We’d also like to acknowledge the importance of engagement with the industry to develop our knowledge about commercial solutions and their relevant availability. We use pathfinder projects to deliver our first attempt to a new market and will continue to engage with providers and other stakeholders through these projects.
High Voltage Management Process	The ESO is expected to undertake clear, publicised and open assessment of options with a transparent benchmark.	We support the initiative of being open and transparent in the High Voltage Management Process and hence we have included a detailed methodology in the NOA 2019/20 methodology. We anticipate to publish the relevant information

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		at each stage of the process in a timely manner. A regional report on the High Voltage Management Process will also be published after all the analysis and tender activities conclude. We will also continue to explore the ability to publish costs of all solutions considered in the High Voltage Management Process, including TO, DNO and Reactive Power Service options.
High Voltage Management Process	Combining requirements e.g. voltage support, stability, constraint management etc. can maximise the cost-effectiveness of solutions.	We intend over time to bring together our needs identification such that for a region we assess the requirements for all considered system needs. The speed at which we can achieve this will depend on the success (or otherwise) of the pathfinder projects, e.g. voltage pathfinder and stability pathfinder, looking at individual needs.
High Voltage Management Process	Information asymmetry in the process - Information and modelling capabilities available to Network Owners are superior when compared to other parties.	We have obligations to share network information and models relevant to system planning with TOs under the STC and DNOs under the Grid Code. As part of our ambitions set out in the Network Development Roadmap we are also looking to enhance the information we provide to non-network parties. We aim to ensure that all parties have the necessary information to be able to offer solutions to any identified system need. We'll continue to engage with stakeholders on the information we provide and welcome feedback on how we are doing.
High Voltage Management Process	Costs of connection need to be fairly allocated in the assessment.	A number of potential Reactive Power Service providers pointed out in the recent RFI for Reactive Power Service in Mersey that i.) any sole use connection work will be paid for in full by the User and ii.) for any socialised elements of the connection they pay a use of system charge or the equivalent. We acknowledge the design of the existing Connection Process and Charging Statement of each network owners, and that the Users pay accordingly. Hence, we've amended the draft methodology to reflect the feedback received in Table 6.2.
High Voltage Management Process	The process should be designed in a timely manner. TOs have a licence obligation to develop a compliant network efficiently and in a timely manner. There is also concern about whether the use of a screening process to select and prioritise regions in the High Voltage Management Process will	We agree that it is important any decision to network planning should be made in a timely manner that ensures an economic and efficient network. We also acknowledge the responsibility of TOs to transmission network compliance and that of DNOs to distribution network compliance. We've reflected on the design of the High Voltage Management Process and we've added further details on "programme" and made further clarifications to "roles and responsibilities" in the

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	impinge on TOs' ability to comply with licence obligations. Any proposed timeline should be reasonable considering the volume of options to be assessed and agreed by the ESO, TOs and DNOs.	methodology. We will engage with the TOs to understand the typical lead time for delivery of reactive power compensation for high voltage issues. This will help ensure recommendations of the most economic and efficient solution can be made in a timely manner but not too early to avoid unnecessary stranding risks due to future uncertainty. We anticipate analysis of the network 3-5 years ahead once the High Voltage Management Process becomes business-as-usual. This will allow sufficient time for the process to deliver recommendations in a timely manner. We will agree the timeline of regional analysis with the relevant TOs and DNOs. We've also added further details on how compliance concerns will be dealt with in 6.18 and 6.19. We'll discuss any compliance concerns raised by the TOs and agree a plan to assess these concerns in a timely manner.
High Voltage Management Process	Further development is necessary to ensure clarity of the roles and responsibilities of all parties (ESO, TOs and DNOs). This includes TOs' and DNOs' roles to: • network compliance • identifying requirements • preparing network models • coordination to develop and assess impact of whole system solutions	We've reflected on the design of the High Voltage Management Process and made further clarification to "roles and responsibilities" and the relevant paragraphs throughout Section 6. We acknowledge the responsibility of TOs to transmission network compliance and that of DNOs to distribution network compliance. We support the principle that we should work collaboratively with the TO to define any high voltage requirement in a timely manner. This will ensure the TO has sufficient confidence and time to proceed with their option to achieve network compliance if their option is the most economic and efficient, while we seek alternative options from the market. We also agree there're greater overlaps of the roles and responsibilities of the ESO, TOs and DNOs in relation to preparing network models for analysis. However, we think it is essential for the assessment of options to remain a responsibility of the ESO (for technical and cost-benefit assessment) and the relevant DSO (for technical assessment) only when a tender process may be involved in the High Voltage Management Process. This helps ensure an assessment in which all participating parties feel they are treated fairly. We will work collaboratively with the relevant DSO throughout the technical assessment to ensure any concerns caused by any of the solutions in the distribution networks are considered as part of the assessment. We acknowledge that a relevant DSO function may not exist yet now;

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		where we then expect the relevant DNO will perform the technical assessment collaboratively with us instead of the DSO. We'd also like to clarify that we expect all new options recommended by this process to eventually follow the existing Connection Process to obtain a connection to either the transmission or distribution network, where TOs and DNOs will assess the impact of these options connecting to their networks and coordinate for the whole system benefits. For the avoidance of doubt, a recommendation by this process doesn't automatically guarantee a connection to the system. We'd also work with the relevant parties to ensure we consider the costs to consumers (including any socialised network costs where applicable) appropriately throughout the assessment.
High Voltage Management Process	There is a lack of regulatory, legal and commercial framework of solution provision (except for TOs). Hence it is not clear how all solutions are to be appraised on a level playing field.	We've proposed a methodology to compare the costs and benefits of options from TOs, DNOs and Reactive Power Service Providers in the "cost-benefit analysis" section. We'd like to clarify that the "assessment period" or "service year" is not set to a standard 10-year period. Assessment period is defined as the years over which the future voltage control requirements are reasonably clear and certain (paragraph 6.69). This will be decided based on various factors, for example: • the detailed network models that are available (this is up to 10 years ahead currently in the planning process within NOA) • the degree of divergence in the future scenarios • the economic benefits expected to be achieved by recommending a solution Service years is defined as time that the option will be available and cost-effective within the assessment period (paragraph 6.79). All options will be compared on a £/MVAr basis initially. Combinations of options are then optimised to ensure the most economic and efficient solution is recommended over the course of the assessment period. We're open to ideas to improve the process currently set out in this methodology. We'd encourage discussion of these ideas through any of our stakeholder channels or bilateral meetings.

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High Voltage Management Process	Consider introducing the concept of “asset reuse factor” in the assessment to reflect typical asset life.	We’re open to ideas to improve the process currently set out in this methodology. We’d be delighted to work with the industry in the future to explore other concepts such as an “asset reuse factor” if that proves to be a practical alternative way to assess network owner options. We’d encourage discussion of these ideas through any of our stakeholder channels or bilateral meetings.
High Voltage Management Process	Need to improve and extend long-term reactive power forecast.	We’re open to ideas to improve and extend the long-term forecast of reactive power needs and we’d encourage discussion of these ideas through any of our stakeholder channels or bilateral meetings. We currently look to utilise data from FES and methodology from SOF to inform our assumptions, which are also widely consulted.
High Voltage Management Process	Consideration must be given to the cost associated with increased levels of activity by the DNOs to assess options connected to the distribution network to resolve transmission constraints. A Modification Application approach but in reverse should be considered. Further work to develop a long-term regulatory funding mechanism for Whole System planning proposals is required.	We agree that consideration needs to be made to the cost associated with the increased levels of activity by the DNOs and which there is currently no funding in RIIO-1. We are considering options, including a reverse Modification Application, and also through the ENA engaging on funding mechanisms for these types of assessments now and in RIIO-2.
High Voltage Management Process	It is incorrect to assume operational actions on the distribution network would be at zero costs. The costs of these actions should be factored into the CBA with DNOs compensated accordingly.	We’d like to clarify that where the methodology refers to “optimise existing assets” at the early stages we expect the use of TO or DNO assets within the standard practices. Any operational actions that the TOs or DNOs considered as non-standard operational actions, where there will be extra costs associated with those actions, should form part of the CBA and will only be recommended if the CBA supports such decision.
High Voltage Management Process	Any socialised costs should be incorporated as part of the assessment to reflect the true cost to consumers and enable a fair comparison.	We expect any recommended options to follow the existing Connection Process to obtain a connection to either the transmission or distribution network. We hence expect any sole use infrastructure by these options to be paid for by the providers as they currently do as part of the Connection Process. For any socialised costs, the providers pay the use of system charges according to the relevant Charging Statement of each network owners. Therefore, we do not think it is appropriate to apply a “connection-related cost” element separately to the market-based options in the CBA.

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High Voltage Management Process	How will solutions connected to the distribution networks be dispatched?	We acknowledge this is a new arrangement and we're currently considering several options. The voltage pathfinders e.g. Mersey voltage pathfinder will explore how best to dispatch these options.
High Voltage Management Process	The credibility and deliverability of options must be assured, as failure to do so may result in increased costs to consumer and potential system security and operability implications.	There are delivery risks associated with any solution, whether this is a market-based option, or one delivered by a TO or DNO. We recognise however the potential risks due to non-delivery. As such any market-based options to be delivered by commercial providers will be subject to financial penalties if they failed to deliver the service they're contracted for. The penalty terms will vary depending on the nature of system needs, for example we expect a higher penalty to be applied if the service is for compliance needs.
NOA for Interconnectors	Revise the method for setting the baseline interconnection level	We will revise the method used for setting the baseline interconnection level to ensure that the solution cannot inadvertently be seen to be favouring specific projects. The method will be transparent and shared with our stakeholders.
NOA for Interconnectors	Continue to provide a range of optimal interconnection capacities based on the Future Energy Scenarios	We agree that providing a range provides more value than a single solution, and we will continue with this approach for NOA IC 2019/20.
NOA for Interconnectors	Consider reinforcement upgrades greater than 1GW	We will investigate whether additional value may be delivered by modelling a range of sizes for potential reinforcement upgrade options.
NOA for Interconnectors	Use NOA IC as a signpost to other system operability work, with more information and transparency of the balancing services market	We agree that a more holistic assessment of all technologies and their potential impact on system operability will provide more valuable insights. These insights will be delivered via the System Operability Framework.
NOA for Interconnectors	Increase transparency of NOA IC source data, especially for European countries	We will highlight any changes made to data sources or modelling assumptions, and will improve transparency of source data, where we own the data.
NOA for Interconnectors	Focus on expanding the GB market and network information	We will refocus NOA IC on providing additional value from the main iterative analysis, by improving the GB-specific constraint and network analysis as well as drawing greater insights from the use of the European FES.
NOA for Interconnectors	Greater focus on environmental impacts	We agree, a more in-depth analysis of the impact of additional interconnection on carbon content and RES usage will be of increased benefit as GB aims to reduce emissions to net zero by 2050.