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.

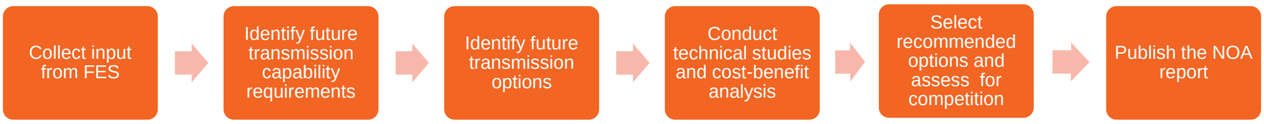

Figure 2. 1 Overview of the NOA report process

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)*	✓	✓	✓	
Alternative Options	Operational Options	Reactive demand reduction *(this could ease voltage constraints)*		✓		
Alternative Options	Operational Options	Enhanced generator reactive range through reactive markets *(generators contracted to provide reactive capability beyond the range obliged under the codes)*		✓	✓	
Alternative Options	Operational Options	Demand side services (contracted for certain boundary transfers and faults). *These allow peak profiling which can be used to ease boundary flows*	✓	✓		
Alternative Options	Operational Options	Intertrip *(normally to trip generation for selected events but could be used for demand side services)*	✓	✓	✓	
Alternative Options	Operational Options	Generation advanced control systems *(such as faster exciters which improves transient stability)*		✓	✓	
Alternative Options	Reduced-build Options	Co-ordinated Quadrature Booster (QB) Schemes *(automatic schemes to optimise existing QBs)*	✓	✓		
Alternative Options	Reduced-build Options	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)*	✓	✓	✓	✓
Alternative Options	Reduced-build Options	Dynamic ratings *(circuits monitored automatically for their thermal and hence rating capability)*	✓			
Alternative Options	Reduced-build Options	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)*		✓	✓	
Alternative Options	Reduced-build Options	Protection changes *(faster protection can help stability limits while thermal capabilities might be raised by replacing protection apparatus such as current transformers (CTs))*	✓		✓	
Alternative Options	Reduced-build Options	HVDC de-load Scheme *(reduces the transfer of an HVDC Intralink either automatically following trips or as per control room instruction)*	✓	✓	✓	
Alternative Options	Reduced-build Options	'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)*	✓			
Alternative Options	Reduced-build Options	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.