Network Options Assessment Methodology

System Operator

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nationalgrid

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About this document

This document contains National Grid's Network Options Assessment (NOA) methodology established under NGET Licence, Licence Condition C27 in respect of the financial year 2016/17. It covers the three methodology documents on which NGET in its role as SO will base the NOA processes in 2016/17.

Network Options Assessment Methodology

Foreword

This document contains National Grid's Network Options Assessment (NOA) methodology established under NGET Licence, Licence Condition C27 in respect of the financial year 2016/17. It describes how the System Operator (SO) meets these obligations which are broken down into the three components below:

- Network Options Assessment Report methodology
- Network Options Assessment for Interconnectors
- SO Process for Input into Transmission Owner (TO) Led Strategic Wider Works (SWW) Needs Case Submissions.

NOA Report methodology describes how we assess options for reinforcing the National Electricity Transmission System to meet the requirements that the SO finds from its analysis of the Future Energy Scenarios. This methodology includes the proposed form of the NOA report.

NOA for Interconnectors details the methodology for the analysis and publication of the NOA for Interconnectors report. It includes an introduction to social and economic welfare benefits and analysis.

SO Process for Input into TO Led SWW Needs Case Submissions documents how the SO supports the Transmission Owners (TO) in their creation and development of Needs Cases through to the submission to Ofgem.

We have taken the approach of three component documents for the second year of the NOA process to ease the transition and evolution of existing processes into new ones. While we have written the three component documents so that they can be read in isolation, we expect that in future years these component parts will be brought together into a single NOA methodology.

Network Options Assessment Report Methodology

System Operator

September 2016

Version	**FINAL 2.1**
Date	**9 September 2016**

About this document

This document contains National Grid's Network Options Assessment (NOA) Report methodology established under NGET Licence, Licence Condition C27 in respect of the financial year 2016/17. It covers the methodology on which NGET in its role as SO will base the NOA report which will be published by 31 January 2017. 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.

Network Options Assessment Report Methodology

Contents

Introduction

Overview

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 interconnector capacity.

2 This document provides an overview of the aims of the NOA and details the methodology which describes how the System Operator (SO) assesses the required levels of network capability, the options available to meet this capability and the SO's preferred options for further development. It is important to note that whilst the SO identifies its preferred options to progress to meet system needs, any investment decisions remain with the Transmission Owners (TOs) or other relevant parties as appropriate.

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

4 For the second NOA Report methodology, the SO assesses options for competition in providing transmission reinforcements and also does validation checks of boundary capabilities where the TO does this analysis. The SO has procured a new constraint costing modelling tool to replace ELSI and will introduce the tool during the NOA Report study period.

5 In order to recommend options, the SO uses the established NOA investment decision process. This ultimately leads to the selection of preferred options based upon their capital investment and constraint savings across a range of Future Energy Scenarios (FES). 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.

6 Occasionally there is a risk that an option is justified based upon just one scenario alone which doesn't always guarantee efficient and economic network planning if system evolution were not to follow that particular scenario. In this event, the SO would examine that scenario further. How we do this varies according to circumstances. Our analysis helps us to understand the elements(s) within a scenario that drive a particular outcome. This in turn informs our view on the robustness of the outcome and thus whether to make a recommendation based on this scenario. All current FES are considered to represent an envelope of credible outcomes and the SO ensures that no one scenario unfairly skews results. Further detail of how the SO achieves this is given in section "Single Year Least Regret Decision Making". In addition to analysing the FES, it also looks at sensitivities where specific projects could create a disproportionate level of regret. The areas of study

are outlined in Appendix B. The SO is investigating the development of probabilistic tools to deliver year round network analysis, and further ensure that all sensitivities are covered, but this is at an early stage and not likely to be available for NOA use until the end of decade.

7 The SO performed validation checks of boundaries assessed in the first NOA Report. The constraint cost modelling tool (ELSI at that time) used assumptions to scale the boundary capabilities. It scaled the capabilities from the winter reference values to values for other seasons and also for outages. The purpose of the 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 need only slight adjustment. Appendix B gives a more detailed review of the validation checks. The SO will continue to perform validation checks for the second NOA Report.

8 The NOA Report process was built on the Network Development Policy (NDP) process and extended its use to the whole Great Britain transmission system. The NDP is part of the evaluation of National Grid TO investment under its volume-driver (incremental wider works (IWW)) framework and so the SO is looking to fully replace the NDP with the NOA analysis.

9 Where this methodology refers to ‘TOs’, it means onshore TOs.

10 This methodology describes the process and the headers used follow the flow diagram in Appendix C for clarity. Appendix D contains supporting information and Appendix E is the form of the NOA Report.

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

Differences between NOA and ETYS

12 The NOA process is an obligation under NGET Licence, 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 SO’s best view of options for reinforcements for the national electricity transmission system together with alternatives and preferred options.

13 The Electricity Ten Year Statement (ETYS) is an obligation under NGET Licence, Standard Licence Condition C11 (Production of information about the national electricity transmission system). Paragraph 3 defines ETYS’ required contents which are the SO’s best view of the design and technical characteristics of the development of the national electricity transmission system and the system boundary transfer requirements.

14 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

15 The Network Options Assessment (NOA) process set out in Standard Licence Condition C27 of the NGET Licence 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 of the NGET licence.

16 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, through assessing available solutions, to selecting and documenting the recommended option/s for further development and assessing the suitability of options for third party delivery by a Competitively Appointed Transmission Owner (CATO). This assessment will be against criteria defined by Ofgem in anticipation of legislation which at the time of writing has yet to be published. The SO identifies and evaluates alternative solutions such as those based around commercial arrangements and reduced-build options. Table 1 covers this in more detail.

17 The SO has engaged with the TOs to develop this second methodology statement. Following publication of the NOA report further stakeholder engagement is undertaken to inform the methodology statement for supporting the second NOA Report (2016) and further NOA reports.

18 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.

19 The SO engages stakeholders on the annual updates to the key forecast data used in this decision-making process, and shares the outputs from this process through the publication of the NOA report.

20 Transmission Licence Standard Condition C27 Paragraph 15 sets out the contents of the NOA report:

> 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;
>
> (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.

21 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

22 Standard Licence Condition 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 SO 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.*

23 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 system benefits might be a user connection or improved system reliability.

Eligibility criteria for projects for inclusion / exclusion

24 The NOA report presents projects that are defined by Major National Electricity System Reinforcements (see definition above).

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

26 Once a Strategic Wider Works (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 because it is managed through the SWW process.

Ofgem have agreed the approach of excluding options where they have agreed the SWW needs case. The NOA Report will include analysis of options under construction that are funded through the Incremental Wider Works mechanism.

Roles and responsibilities of SO and TOs

27 The roles and responsibilities of the SO and TOs are described below. However, as the NOA process evolves and matures, these roles and responsibilities will also develop and change.

28 The SO role and responsibilities are based around its overview of the network requirements. Specific role areas are:

- Analysis of UK Future Energy Scenarios (FES) data
- Technical analysis of boundary capabilities for England and Wales
- Running cost-benefit analysis studies
- Production and publication of NOA report
- Recommending options for further development and suitability for competition
- Devising and developing options for alternative reinforcements including reduced-build and Offshore Wider Works
- Validation checks of some TO boundary capabilities where the TO has done that analysis
- Review of reinforcement options and their cost estimates that the TOs propose
- Advice on the performance of boundary reinforcement proposals in the cost-benefit analysis to facilitate further option development
- Assessment of outages and other system access requirements that might affect the Earliest in Service Date (EISD).

29 The TOs' roles and responsibilities include:

- Technical analysis of boundary capabilities by SPT and SHE Transmission in and affecting their areas[1]
- Cost information
- Environmental information
- Consents and deliverability information
- Capability improvements
- Earliest in Service Date (EISD)
- Stakeholder engagement (following review of draft outputs)
- Community engagement.

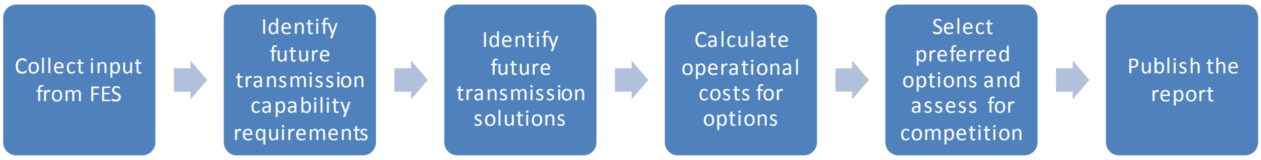
Overview of the NOA Report process

30 Figure 1 gives an overview of the NOA Report process. This methodology describes how the SO, working with the TOs carries out these activities. The process diagram

[1] This is anticipated for the first, second and possibly further NOA reports.

in Appendix C gives more details. The headers in this methodology follow the stage names in the process diagram in Appendix C.

Figure 1: Overview of the NOA Report process



Collect Input

Updated Future Energy Scenarios

31 The relevant set of Future Energy Scenarios (FES) as required by NGET Licence, 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 2040 in detail and at a higher level to 2050. The FES document is consulted upon widely and published each year as part of a parallel process.

32 The NOA process utilises the main FES 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 consultation report that is published each year.

33 In 2016, the four main scenarios are:

- Gone Green – The Gone Green scenario represents a potential generation and demand background which maintains progress towards the UK's 2050 carbon emissions reduction target. The achievement of the climate change targets requires the deployment of renewable and low carbon technologies. EU aspirations regarding interconnector capacity for each member country remain applicable.

- Slow Progression – Slow Progression is a scenario where secure, affordable and sustainable energy sources are the political objectives, but the economic conditions are less favourable than under Gone Green. Therefore carbon reduction policies cannot be implemented as quickly. The focus on the green agenda ensures that the generation landscape is shaped by renewable technology. Ambition for innovation is constrained by financial limitations, which, in comparison to Gone Green, leads to a slower uptake of renewables.

- No Progression – No Progression is a scenario where secure and affordable energy sources are the major political objective and there is less of a focus on sustainability. This means that ambitious carbon reduction policies are not expected to be implemented. Gas and existing coal feature in the generation mix over renewables and nuclear, with focus being on the cheapest sources of energy. The lack of focus on the green agenda and limited financial support available for low carbon results in a limited new build programme for nuclear and minimal deployment of less established technology.

- Consumer Power - Consumer Power is a scenario where there is high prosperity but less political emphasis on sustainable energy policy. There is more money available in the economy to both consumers and Government, but there is a lack of political will for centralised carbon reduction policy. The favourable economic conditions encourage development of generation at all levels. There is high renewable generation at a local level and high volumes of gas generation at a national level. There is less focus on developing low carbon technologies to meet environmental targets. As such, technologies such as carbon capture and storage (CCS) do not reach commercialisation.

34 The demand scenarios are created by using a mix of data sources, including feedback from the FES consultation process. The overall scenarios are a composite of a number of sub-scenarios: inputs; the key scenarios being the economic growth projections, fuel prices, domestic heat/light/appliance demand, and projections of manufacturing and non-manufacturing output. Other inputs include (but are not limited to) small scale generation, consumer behaviour and the effect of smart meters/time of use tariffs and new technologies (e.g. electric vehicles, heat pumps. LED light bulbs). The scenario demands are then adjusted to match the metered average cold spell (ACS)[2] corrected actual outturns.

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

36 Annual demand submissions are made by transmission system users, which are obtained between June and November each year. The regionally split “ACS adjusted demand scenarios” are then converted into demand by Grid Supply Point using the same proportions as specified in the ‘User’ submissions.

Sensitivities

37 Sensitivities are used to enrich the analysis for particular boundaries to ensure that issues, such as the sensitivity of boundary capability to the connection of particular generation projects, are adequately addressed. In England and Wales the SO leads on the sensitivities in conjunction with the TOs and any feedback from stakeholders sought through the FES consultation process. In Scotland the TOs create the sensitivities in conjunction with the SO. The SO 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.

38 For example, the contracted generation background on a national basis far exceeds the requirements for credible 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] 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.

39 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.

40 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 into GB) and demand (when exporting to Europe). For example, when interconnectors in the South East are exporting to Europe, this changes the loading on the transmission circuits in and around London and hence creates different limits on the amount of power that can be transferred.

41 The SO produces its expected interconnector power flows from economic simulation using a market model of forecast energy prices for GB and European markets. The interconnector market model has been improved for 2016 as it 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 can be eliminated for unlikely interconnector flow scenarios.

42 The SO extends sensitivities studies further to test import or security constraints. FES tends to produce export type flows such as north to south. In some circumstances, flows are reversed. The SO develops these sensitivities in consultation with stakeholders to produce transfer requirements for import cases.

Interconnectors

43 For the NOA for Interconnectors (NOA IC) report, the SO undertakes analysis to assess and provide a view on the optimum level of interconnectors' capacity per interconnected market. The markets considered are Belgium, Denmark, France, Germany, Iceland, Ireland (the combined market of Northern Ireland and the Republic of Ireland), the Netherlands, Norway and Spain. The NOA IC report is independent from the NOA Report.

44 The SO has procured a new Pan-European Market Model tool to enhance its capabilities in simulating inter-market flows and consequent prices changes. This allows the evaluation of potential benefits and costs of further interconnection capacities. The chief benefits analysed will be consumer, producer and interconnector welfare benefit for GB and Europe, while costs captured will include capital expenditure. The SO anticipates the market will respond to this intelligence with potential projects aligned with the optimum level of interconnectors recommended by the SO.

45 The details of the proposed approach for 2016/17 are presented in the NOA for Interconnectors methodology. The NOA for Interconnectors will be a chapter in the NOA Report and hence be published by 31 January 2017.

Offshore Wider Works (OWW)

46 The SO has written the NOA Report methodology so that it treats all options for system reinforcement in the same way, in other words on a 'level playing field'. These options can include OWW.

47 The licence condition gives the SO the duty to devise and develop OWW. The SO 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 will be published for consultation during August. This methodology is the SO Process for Offshore Wider Works and covers both developer-associated and non developer-associated works.

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

48 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 capability requirements

National generation and demand scenarios

49 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 and other seasonal demands (spring/autumn and summer) is used to outline the minimum required transmission capability for both the Security and Economy criteria set out in the NETS SQSS.

50 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.2.2. The level of contribution from the remaining generators is established in accordance with the NETS SQSS for assessing the average cold spell (ACS) peak demand[3]. Further explanation can be found in Appendices C and D of the NETS SQSS. To investigate the system against the Security criterion, the SO and TOs to identify key network contingencies (system faults) that test the system's robustness. The SO does this by using operational experience from the current year and interpreting this in terms of network contingencies. It uses these directly in studies but also uses them to identify trends or common factors and apply them in the NOA Report analysis to ensure that TO options do not exacerbate these operational issues. This might lead to an investment recommendation.

51 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 Appendix E and F of the NETS SQSS.

52 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:

[3] ACS 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.

- Ensure adequate voltage and stability margins for year-round operation

- Ensure reasonable access to the transmission system for essential maintenance outages.

53 The SO uses the FES 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 SO then passes this information to TOs for identification of the future transmission solutions which are described in the following section.

Identify future transmission solutions

54 At this stage all high level potential transmission solutions that could provide additional capability across a system boundary found to be requiring reinforcement are identified (for economic and security criteria), including a review of any solutions previously considered. The NOA report presents a high level view of options, with key choices to be taken for further evaluation as outlined on a non-exhaustive basis below. The NOA options are based around choices for example:

- An onshore route of conventional AC overhead line (OHL) or cable

- An onshore route of HVDC

- Offshore options whether 'bootstrap' or integration between offshore generation stations (Offshore Wider Works).

55 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.

56 In response to the SO data on boundary capabilities and requirements, TOs identify and develop multiple credible options that deliver the potentially required reinforcements of boundaries. The SO produces and circulates the System Requirement Forms (SRF) to the TOs and in return, TOs provide high level details of credible onshore reinforcement options that are expected to satisfy the requirement. Appendix D of this document provides detailed information about the SRF template. The SO can suggest ideas to the TOs for options to achieve the boundary requirements.

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

58 The options that the TOs provide are listed and described in the NOA report along with 'reduced-build' options such as operational or 'minimal-build' options that the SO develops. The reduced-build solutions might include liaison with distribution licensees. The SO produces the description of the 'reduced-build' option in

conjunction with the relevant TOs. The description includes the boundary that the option relieves, categorising the option into 'asset', 'reduced build' etc and a technical outline such as an overhead line route connecting substation 'X' to substation 'Y'. The option description includes any associated aspects such as the nature of the area affected, related network changes for example substation rebuilds etc.

59 It is recognised that as solutions develop, their level of detail increases. Solutions at a very early development stage might lack detail due to emerging drivers such as a changing generation background.

60 By the end of Week 23, the England and Wales TO returns the draft SRF with the necessary technical content for the SO to perform the boundary capability assessment. The England and Wales TO returns the full SRF form that includes costs and further commentary by the start of Week 38.

61 The Scottish TOs return the draft SRF by the end of Week 32. By the start of Week 38, the Scottish TOs return the full SRF with the boundary capabilities from their technical assessment of the credible reinforcement options for their respective areas.

62 Where a boundary reinforcement affects an adjacent TO, the TOs and SO coordinate their views on the reinforcement options and produce an agreed set of options by Week 32. The SO then uses the agreed set of options in its boundary capability analysis (for England and Wales) and for the economic analysis. If there is no agreement, the SO forms a view on which options it assesses.

63 Once the TOs have submitted their SRFs, the SO checks its data and understanding of the costs by discussing them with the TOs.

64 SO and TOs agree the combinations of options that the SO will use in the cost-benefit analysis.

65 Potential transmission solutions are presented in Table 1.

Table 1: Potential transmission solutions

Category		Transmission solution	Nature of constraint			
			Thermal	Voltage	Stability	Fault Levels
Operational		Availability contract *(contract to make generation available, capped, more flexible and so on to suit constraint management)*	✓	✓	✓	
Operational		Intertrip *(normally to trip generation for selected events but could be used for demand side services)*	✓	✓	✓	
Operational		Reactive demand reduction *(this could ease voltage constraints)*		✓		
Operational		Generation advanced control systems *(such as faster exciters which improves transient stability)*		✓	✓	
Investment	Low cost-investment	Co-ordinated Quadrature Booster (QB) Schemes *(automatic schemes to optimise existing QBs)*	✓	✓		
Investment	Low cost-investment	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)*	✓	✓	✓	✓
Investment	Low cost-investment	Dynamic ratings *(circuits monitored automatically for their thermal and hence rating capability)*	✓			
Investment	Low cost-investment	Enhanced generator reactive range through reactive markets *(generators contracted to provide reactive capability beyond the range obliged under the codes)*		✓	✓	
Investment	Low cost-investment	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)*		✓	✓	
Investment	Low cost-investment	Demand side services which could involve storage (contracted for certain boundary transfers and faults). *These allow peak profiling which can be used to ease boundary flows*	✓	✓		
Investment	Low cost-investment	Protection changes *(faster protection can help stability limits while thermal capabilities might be raised by replacing protection apparatus such as current transformers (CTs))*	✓		✓	
Investment	Low cost-investment	HVDC de-load Scheme *(reduces the transfer of an HVDC Intralink either automatically following trips or as per control room instruction)*	✓	✓	✓	
Investment	Low cost-investment	'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)*	✓			
Investment	Asset investment	Overhead line re-conductoring or cable replacement *(replacing the conductors on existing routes with ones with a higher rating)*	✓			
Investment	Asset investment	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.*		✓	✓	
Investment	Asset investment	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).*	✓			✓
Investment	Asset investment	New build (HVAC / HVDC) – *new plant on existing or new routes.*	✓	✓	✓	✓

66 It is intended that the range of solutions 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 SO applies a sense check in conjunction with the TOs and builds an understanding of the options and their practicalities. In this way, the SO narrows down the options while it allows the SO to assess the most beneficial solution for customers. Other than the application of economic tools and techniques, to refine a shortlist of options or identify a potential preferred solution, the SO relies on the TO for deliverability, planning and environmental factors. We offer a lead on operability, reduced-build and offshore integration matters ahead of the cost-benefit analysis.

67 In checking for the suitability of an option, the SO reviews options for their operability and their effect on the wider system. As a result the SO checks for system access, ease of operation and the ability to adhere to operation 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, SPT and SHE Transmission undertake part of this review of options in conjunction with the SO. 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

68 The forecast total cost for delivering the project is split to reflect the pre-construction and construction phases as well as major asset classes. The forecast cost is a central best view.

69 By Week 30, the TOs and SO 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
- Annual expenditure profile reflecting the options' earliest in service dates
- Any major risks for options costed appropriately
- Delay costs
- The TO's WACC

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

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

Environmental impacts and risks of options

72 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.

73 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 SO gives a similar indication on options that it is leading such as OWW.

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.

Scrutiny of the costs that the TOs submit

74 The SO reviews the costs that the TOs submit with their options and checks that they are reasonable. This is to help to ensure the highest quality data goes into the NOA Report process.

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

76 The SO is performing the costs check for the first time as part of the second NOA Report. We expect to gain experience from the checking process that will affect how we manage checks for future NOA Reports.

Build GB Model

77 The Scottish TOs submit a yearly power system model to the SO. The SO then creates the GB power system models and publishes the model for studies. Additional power system model/modelling information for network options should also be submitted from TOs such that SO have adequate models to carry out the necessary option analysis.

Boundary capability assessment for options

78 The SO completes boundary capability assessment studies for England and Wales to feed into the cost-benefit analysis process. The Scottish TOs submit the results of their boundary studies for their own areas with their SRFs. The SO performs validation checks of some TO boundary capabilities where the TO has done that analysis. For the second NOA Report, the SO performs these validation checks after the analysis and uses it to shape the analysis for the third NOA Report.

79 The boundary capability that is assessed is the lowest of the thermal, voltage and stability (where required) capability. Each of these capabilities is assessed at relevant points of the year to ensure that both the peak and off-peak capabilities are considered during the NOA process. In reporting the boundary capability each year, only the most restrictive of the capability values are published and the criteria for its definition provided in any accompanying narrative.

80 In order to minimise unnecessary repetition whilst maintaining robustness, winter peak network analysis is carried out under the FES scenario that will stress the transmission system the most (in 2016 this will be the Gone Green 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. For the purposes of any stability analysis (where required), year round demand condition is 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.

81 The analysis is done in accordance with the NOA study matrix which describes the constraint type, FES 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.

82 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.

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

Table 2: Transmission solution factors

<table>
<tr><th>Factor</th><th colspan="3">Definition</th></tr>
<tr><td>Output(s)</td><td colspan="3">The calculated impact of the transmission solution on the boundary capabilities of all boundaries, the impact on network security</td></tr>
<tr><td>Lead-time</td><td colspan="3">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.</td></tr>
<tr><td>Cost</td><td colspan="3">The forecast total cost for delivering the project, split to reflect the pre-construction and construction phases.</td></tr>
<tr><td rowspan="8">Stage</td><td colspan="3">The progress of the transmission solution through the development and delivery process. The stages are as follows:</td></tr>
<tr><td colspan="3">Project not started</td></tr>
<tr><td rowspan="5">Pre-construction</td><td>Scoping</td><td>Identification of broad need case and consideration of number of design and reinforcement options to solve boundary constraint issues.</td></tr>
<tr><td>Optioneering and consenting started</td><td>The need case is firm; a number of design options provided for public consultation so that a preferred design solution can be identified.</td></tr>
<tr><td>Design/ development and consenting</td><td>Designing the preferred solution into greater levels of detail and preparing for the planning process including stakeholder engagement.</td></tr>
<tr><td>Planning / consenting</td><td>Continuing with public consultation and adjusting the design as required all the way through the planning application process.</td></tr>
<tr><td>Consents approved</td><td>Consents obtained but construction has not started</td></tr>
<tr><td colspan="2">Construction</td><td>Planning consent has been granted and the solution is under construction.</td></tr>
</table>

84 In order to assess the lead-time risk described in Table 2, if a new overhead line solution for example has significant consents and deliverability risks, the SO considers with both ‘best view’ and ‘worst case’ lead-times to establish the least regret for each likely project lead-time.

85 It is possible that alternative solutions 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 solutions, the scenarios or commercial assumptions.

86 If the SO or the Scottish TOs (who conduct boundary capability studies) decide that there are not sufficient options to cover all scenarios, they initiate further work to identify reinforcement options. The TOs and SO aim for at least three options for each reinforcement requirement.

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

88 The Scottish TOs use their boundary capability results in the SRFs that they submit back to the SO.

89 The SO leads on reduced-build options in cooperation with the TOs. The economic analysis tool needs a MW value for the boundary capability which this analysis of reduced-build options must provide. In addition the SO 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

90 Cost-benefit analysis is the best practice approach to inform an investment recommendation for a project. In particular, the approach compares forecast capital costs and monetised benefits over the project's life to inform this investment recommendation.

91 The NOA provides investment signals based on the Single Year Regret Decision Making process. If the investment signal triggers the TO's needs case for SWW assessment by Ofgem, the SO will assist the TO in undertaking a more detailed cost-benefit analysis.

92 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 projects to proceed with or to delay in the next year and which to delay. A secondary output is an indicative list of which reinforcements would be proposed at present if each of the scenarios were to turn out.

93 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[4]. A needs case is submitted by the TO that is proposing the project to the regulator, the needs case includes a cost-benefit analysis section that outlines the financial case for the project. The output of this process is a recommendation of the project that is to be proceeded with.

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

Cost-benefit analysis Methodology

94 Since the number of reinforcements planned for the transmission system is quite large the country is split into regions and each reinforcement is determined to be in one of the regions. The cost-benefit analysis process for each region is conducted in isolation. The year in which each of the reinforcements 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 most recent NOA Report. The definition of a region is fluid and may change from year to year. The criterion by which a region is defined is that a reinforcement may not appear in more than one region (this is to prevent a reinforcement being evaluated more than once, with the risk of two different answers).

95 All of the FES scenarios are considered; furthermore it is usual for sensitivities to be considered as described previously. Each scenario is also 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.

96 To begin the process all proposed reinforcements within the region are disabled, the output of the model is analysed to determine which boundaries within the region require reinforcement and when the reinforcement is required, this simulation is referred to as the base case. This information is used to determine which reinforcement(s) should be evaluated first. The reinforcement that has been selected to be evaluated next is then activated in the constraint cost modelling tool (see the box on page 23 for a description) at its Earliest In Service Date (EISD), if a number of potential reinforcements have been identified as being candidates for the next reinforcement then this process must be repeated with each reinforcement in turn. There are now two sets of constraint cost forecasts, the base case and the reinforced case, which are compared using the Spackman[5] methodology.

97 It is assumed that each transmission asset is to have a 40 year asset life, since the constraint cost modelling tool only forecasts 20 years the constraint costs for each year of the second half of the 40 year asset life are assumed to be identical to the final simulated year (note that this limitation occurs because the FES scenarios do not contain detailed ranking orders beyond 20 years). Both 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 reinforcement is amortised over the asset life using the prevalent Weighted Average Cost of Capital (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 reinforcement.

[5] 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.

98 This cost-benefit analysis process is carried out in a separate comparison tool which also automatically calculates the NPVs if the reinforcement being evaluated were to be delayed by a number of years. This list of NPVs allows the optimum year for the reinforcement, for the current scenario, to be calculated. If a number of alternative candidate reinforcements have been identified then the reinforcement that has the earliest optimum year should be chosen. The chosen reinforcement is then added to the base case and another reinforcement is chosen for evaluation. The process is then repeated until no further reinforcements produce a negative NPV (which would indicate that the capital cost of the reinforcement exceeds the saving in constraint costs). There may be an element of branching if it is not immediately obvious during the process which reinforcement should be chosen to be added to the base case at any given point.

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

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

101 A reinforcement is critical if a decision to delay a reinforcement in the current year means that the optimum year for any scenario or sensitivity, could no longer be met (note that outage availability may play a part in this decision).

Constraint cost modelling tool

102 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 3.

Table 3: 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
CO_2 forecasts	FES	20 year forecast
Plant efficiencies and season availabilities	Historic data	
Plant bid and offer costs	Historic data	
Wind data	Poyry (historic)	Wind load factors for various zones around the UK
Demand data	FES	Annual peak and zonal distribution
Load duration curve	FES	20 year forecast by scenario
Maintenance outage patterns	Historic data	Maintenance outage durations by boundary
System boundary capabilities	Power Factory studies	See text
Reinforcement incremental capabilities	Power Factory studies	See text

103 The model simulates 4 periods per day for 365 days per year and is set to simulate 20 years into the future. The year in which a reinforcement 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.

Selection of preferred option

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

Single Year Least Regret Decision Making

105 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 reinforcement there are two choices, either to proceed with the project for the next year or to delay the project 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

reinforcement 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 reinforcements.

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

107 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.

108 The following section is a worked example of the least regret decision making process. Two projects have been determined to be 'critical' in this region, the EISD for reinforcement 1 is 2018 and the EISD for reinforcement 2 is 2019. The optimum years for scenarios A, B and C are shown in table 4. Note that the scenarios are colour-coded; this is used for clarity in following tables.

Table 4: Example of optimum years for two critical reinforcements.

Scenario	Reinforcement 1	Reinforcement 2
A	2018	2019
B	2018	2022
C	2025	N/A

Table 5: Example decision tree

Permutation	Year 1 Options	Year 1 Capital Costs	Completion Date	Regrets	Worst regret for each permutation
i	Proceed reinforcement 1	£20m	Reinforcement 1: 2018 Reinforcement 2: 2020	£51m	£51m
	Delay Reinforcement 2	£1m	Reinforcement 1: 2018 Reinforcement 2: 2022	£0m	
			Reinforcement 1: 2025 Reinforcement 2: Cancel	£5m	
ii	Delay Reinforcement 1	£2m	Reinforcement 1: 2019 Reinforcement 2: 2019	£102m	£102m
	Proceed reinforcement 2	£10m	Reinforcement 1: 2019 Reinforcement 2: 2022	£35m	
			Reinforcement 1: 2025 Reinforcement 2: Cancel	£10m	
iii	Proceed reinforcement 1	£20m	Reinforcement 1: 2018 Reinforcement 2: 2019	£0m	£15m
	Proceed reinforcement 2	£10m	Reinforcement 1: 2018 Reinforcement 2: 2022	£2m	
			Reinforcement 1: 2025 Reinforcement 2: Cancel	£15m	
iv	Delay Reinforcement 1	£2m	Reinforcement 1: 2019 Reinforcement 2: 2020	£153m	£153m
	Delay Reinforcement 2	£1m	Reinforcement 1: 2019 Reinforcement 2: 2022	£32m	
			Reinforcement 1: 2025 Reinforcement 2: Cancel	£0m	

109 Table 5 is an example of a least regret decision tree, since there are two 'critical' reinforcements there are therefore four permutations. From Year 2 onwards for each of the permutations the reinforcements are commissioned in as close to the optimum year for each reinforcement 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 Year 1 Capital Costs column indicates the expenditure needed in Year 1 and which is key in the Single Year Least Regret analysis. This might include delay costs.

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

- If the reinforcement is delayed and therefore cannot meet the optimum year then additional constraint costs will be incurred
- If the reinforcement is delayed unnecessarily then there will be additional delay costs

- If the reinforcement is proceeded with too early then there will be inefficient financing costs

- If the reinforcement is proceeded with and is not needed then the investment will have been wasted.

111 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 preferred option 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 reinforcements 1 and 2 which has a worst regret of £15m and is the least of the four permutations.

112 As the FES 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 system evolution were not to follow that particular scenario. In this event, the SO would examine the cost-benefit analysis result to establish the causes 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 SO 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 SO 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 FES, significant amounts of generation in FES 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.

Process Output

113 Following Single Year Regret analysis, for each region in the country a list of 'critical' reinforcements for the region is presented with the investment recommendation for each. If the investment signal triggers the TO's needs case, the SO will assist the TO in undertaking a more detailed cost-benefit analysis. The SO 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 on a preferred option.

Suitability for third party delivery and tendering assessment

114 The SO assesses the suitability of projects for competition in accordance with agreed tendering criteria. The cost-benefit analysis process identifies the preferred options. For each set of reinforcements, the SO identifies up to three of the most appropriate options and assesses these options against the tendering criteria, this is projects that are:

- New
- Separable
- High value

The criteria are still to be finalised[6] in legislation and the methodology will include the final criteria. Until the legislation is available the SO provides its best view of the criteria, as defined in Ofgem's relevant policy documentation, to support assessing options for the second NOA Report. To achieve the assessment, the TOs will provide further information to the SO with the SRF form (see appendix D). The SO then carries out the following process:

- Reviews the information provided for each option
- Assesses the options against the criteria for competition for up to three options where this is appropriate
- 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.

Report drafting

115 The SO drafts the NOA report but the responsibility for the content varies between the SO and TOs. The form of the report is subject to consultation and also to Ofgem approval. The NOA report covers the areas in the table below.

Table 6: Overview of the NOA report contents

<table>
<tr><th>Report chapter</th><th>NOA report topic</th><th>Comments</th></tr>
<tr><td>1</td><td>Aim of report</td><td></td></tr>
<tr><td>2</td><td>Methodology</td><td>SO consults with TOs</td></tr>
<tr><td>3</td><td>Boundary Descriptions</td><td rowspan="3">Includes the competition assessment against criteria. See table 7 on next page for fuller description on chapters 3 to 5</td></tr>
<tr><td>4</td><td>Proposed Options</td></tr>
<tr><td>5</td><td>Investment Recommendations</td></tr>
<tr><td>6</td><td>Interconnector Analysis</td><td></td></tr>
<tr><td>7</td><td>Stakeholder Engagement and Feedback</td><td></td></tr>
</table>

[6] The tendering criteria are currently being considered within Ofgem's ongoing work on Extending Competition in onshore Transmission https://www.ofgem.gov.uk/publications-and-updates/extending-competition-electricity-transmission-criteria-pre-tender-and-conflict-mitigation-arrangements

116 Chapters 3 to 6 cover the options and their analysis. The component parts of these chapters and the responsibilities for producing the material are in the table below. Appendix E gives more detail on the form of the NOA Report.

Table 7: Topics in the options chapters in the NOA report

NOA report Options topic	Scotland	E&W	Reduced-build/ min-build	Offshore	Comments
Options: Status of the option (scoping, optioneering, design, planning, construction)	TO	TO	SO / TO	SO	
Options: Technical aspects – assets and equipment	TO	TO	SO / TO	SO	
Options: Technical aspects – boundary capabilities	TO	SO	SO / TO	SO / TO	
Options: Economic appraisal	SO	SO	SO	SO	Leads to preferred options for TOs
Options: Comparison of the options	SO	SO	SO	SO	
Options: Competition assessment	SO	SO	SO	SO	Includes competition criteria and how options were categorised
Table overview of boundaries and options	SO				

117 The report is transparent where possible 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 SO passes outputs to the TOs to support its view of preferred options.

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

Report publication

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

120 On publication the report is placed on the National Grid website in a PDF form that is widely readable by readily available software. The SO 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.

121 Standard Licence Condition C27 Paragraph 10 provides for delaying publication if the Authority (Ofgem) delay their approval of the NOA report methodology or form of NOA report.

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

Stakeholder consultation

123 The SO has consulted with the TOs and Ofgem whilst preparing this NOA report methodology.

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

125 This section shows the timescales for the SO’s consultation of stakeholders during the period of writing the NOA report.

Methodology

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

127 Following the final publication of the NOA report, the SO undertakes an internal review of the NOA process. This is completed within eight weeks of NOA report publication with the publication of an updated NOA methodology that consults stakeholders and invites comments/feedback. The deadline for comments is 14 weeks from NOA report publication. The SO considers these comments for a revised NOA methodology that is published 18 weeks from NOA report publication and submitted to Ofgem by 1 August 2016.

Report output

128 The SO makes available selected parts of the pre-release NOA report to key stakeholders particularly the relevant TOs based on discussions with those stakeholders while respecting confidentiality obligations. This is as the NOA report is being written based on assessment data, particularly economic data, becoming available.

129 Further engagement happens with stakeholders with the draft NOA report being circulated to them three weeks before the NOA report is due to be formally published. This gives them the opportunity 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.

130 The SO 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.

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

131 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.

132 In accordance with Licence Condition C27 Part C, the SO provides information to electricity transmission licensees, interconnector developers and to the Authority (Ofgem) if requested to do so. The SO will assist TOs with cost-benefit analysis for SWW needs cases.

Future developments

133 The SO expects the following changes and developments in the NOA Report methodology and process as it evolves:

- Review of the process to scrutinise costs
- The timing of the validation checks of the boundaries studied by the TOs.
- Probabilistic tools that would need a high level of automation and facilitate:

  a) Year round (24/7/365) consideration of a wide range of possible outturns 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 gens eg wind and solar PV on a regional basis)

  b) Automation of study set-up and contingency analysis

  c) Automated result handling and filtering

  It is not envisaged that such a tool would be available until the end of the decade although some elements might be available sooner once sufficient performance levels and validation have been achieved.

Appendix A: NOA Study Matrix

Assumption/Condition		Comments
Generation and Demand Scenarios	Gone Green	Technical and economic assessment of the reinforcement options; sensitivity studies where appropriate
	Slow Progression	Economic assessment only of the reinforcement options; sensitivity studies where appropriate
	Consumer Power	Economic assessment only of the reinforcement options; sensitivity studies where appropriate
	No Progression	Economic assessment only of the reinforcement options; sensitivity studies where appropriate
Seasonal Boundary Capability	Winter Peak	Technical and economic assessment of the reinforcement options
	Spring/Autumn	Economic assessment, boundary capabilities in NOA will 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	Economic assessment, boundary capabilities in NOA will 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	
	Alternative reduced build reinforcements	Assessment of reduced-build reinforcement options
Study Years	Year 1	Assessment of reduced-build reinforcement options subject to availability
	Year 2	Assessment of reduced-build reinforcement options subject to availability
	Year 3	Assessment of reduced-build reinforcement options subject to availability
	Year 4	Assessment of build and reduced-build reinforcements options excluding those are subject to Ofgem agreement
	Year 5	Assessment of build and reduced-build reinforcements options excluding those are subject to Ofgem agreement
	Year 7	Assessment of build and reduced-build reinforcements options excluding those are subject to Ofgem agreement
	Year 10	Assessment of build and reduced-build reinforcements options excluding those are subject to Ofgem agreement

Appendix B: Validation checks

Introduction

The SO'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 Gone Green 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 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%**

Boundary Constraint	Season	Boundary	Existing ELSI Scaling	Studied Scaling	Relative Difference (ELSI vs Studied)
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 fairly 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

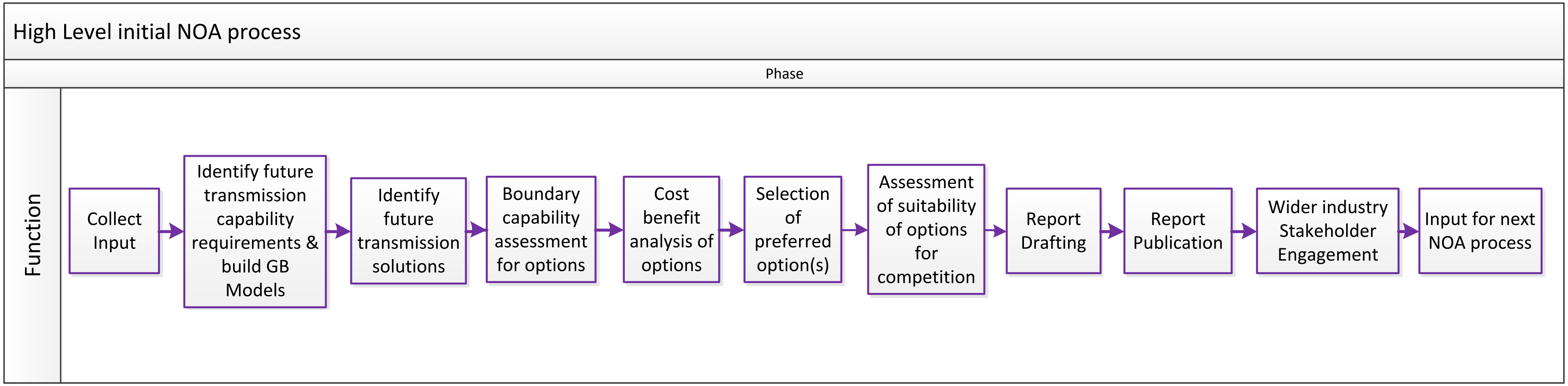
The validation checks led to recommendations to change the scaling factors in the economic model which the table below summarises:

	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%

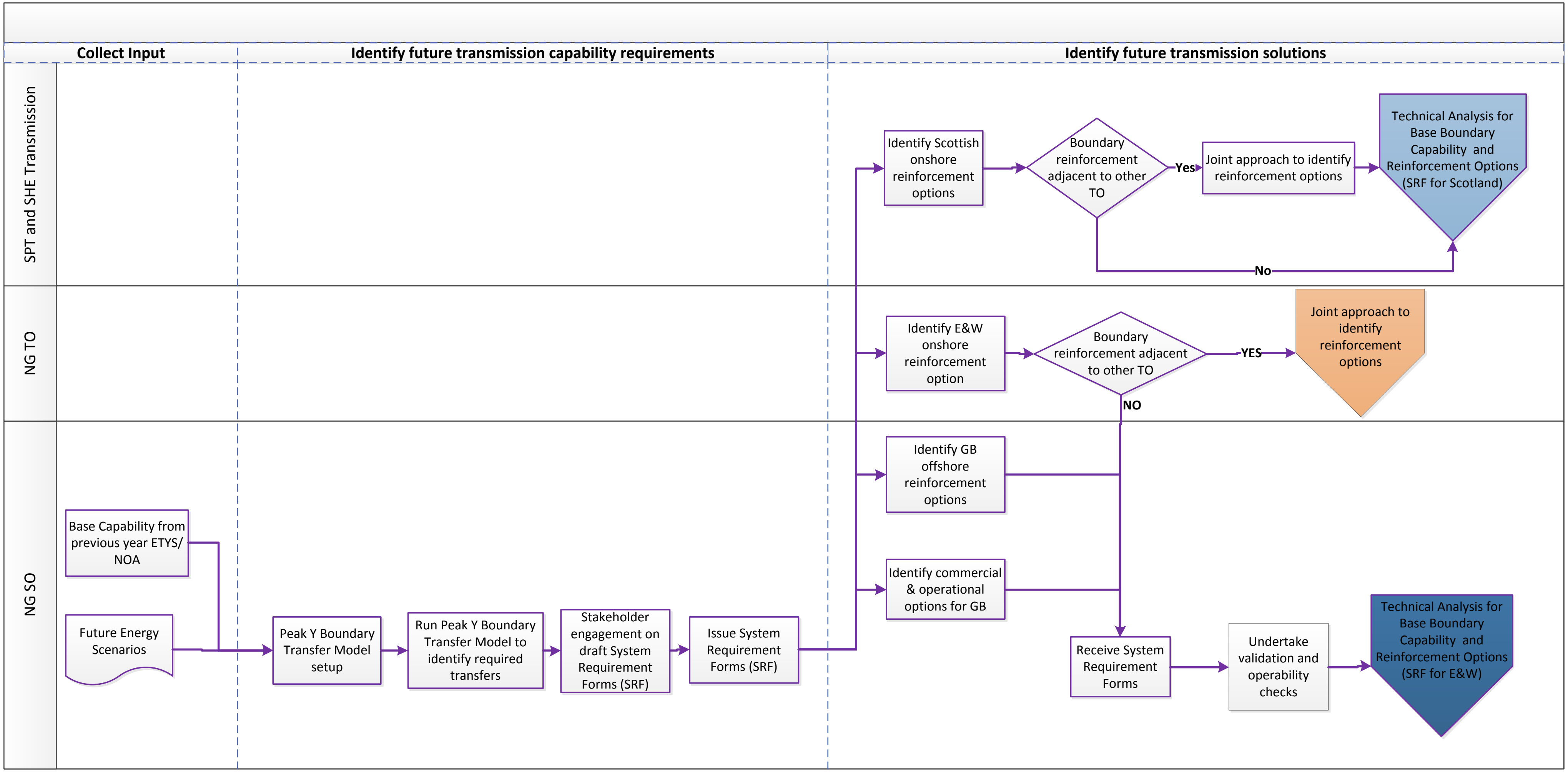
‘n’ is the number of circuits crossing the boundary.

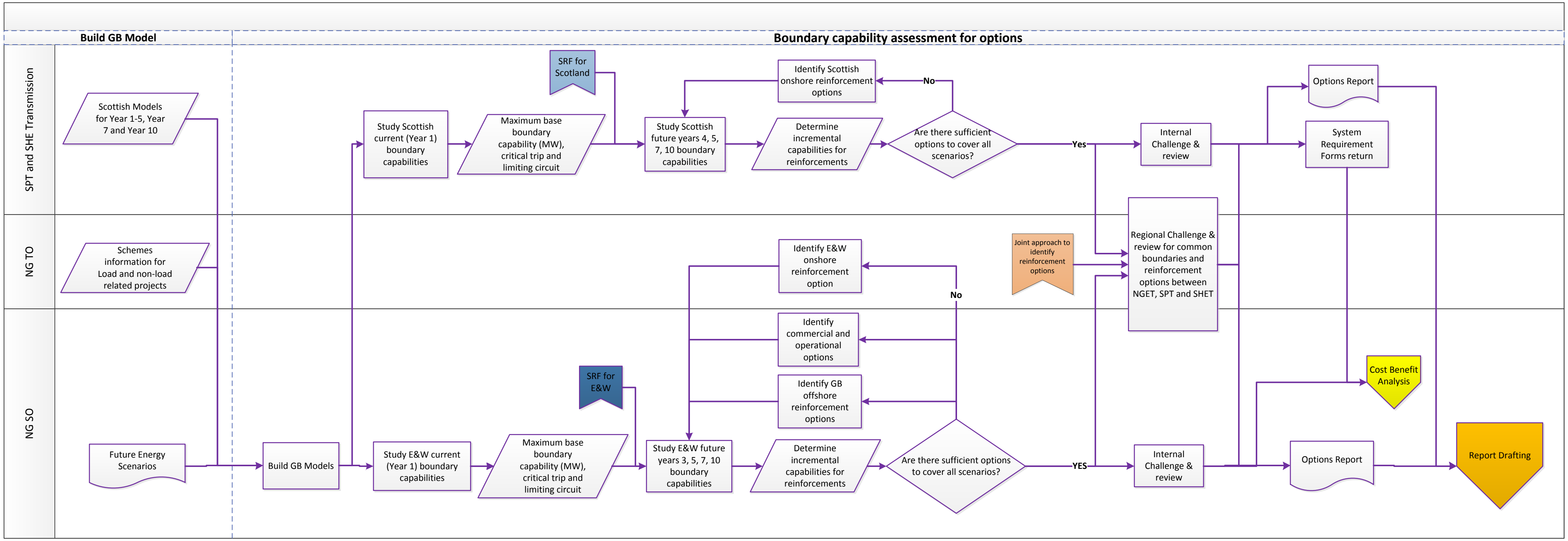
The SO will use these revised scaling factors for the second NOA Report analysis though it might change them with the agreement of the TOs.

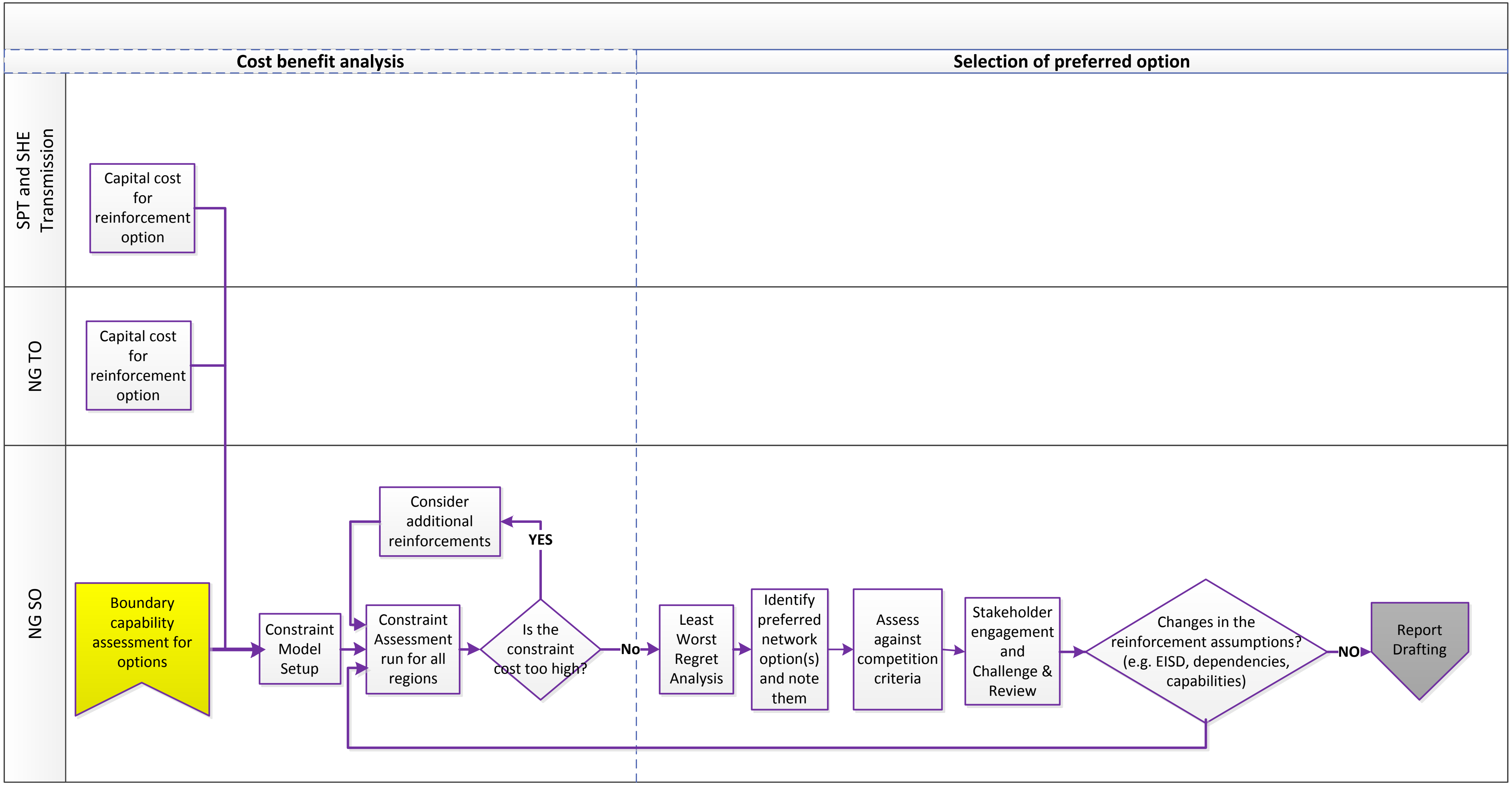
Appendix C: NOA Process Flow Diagram

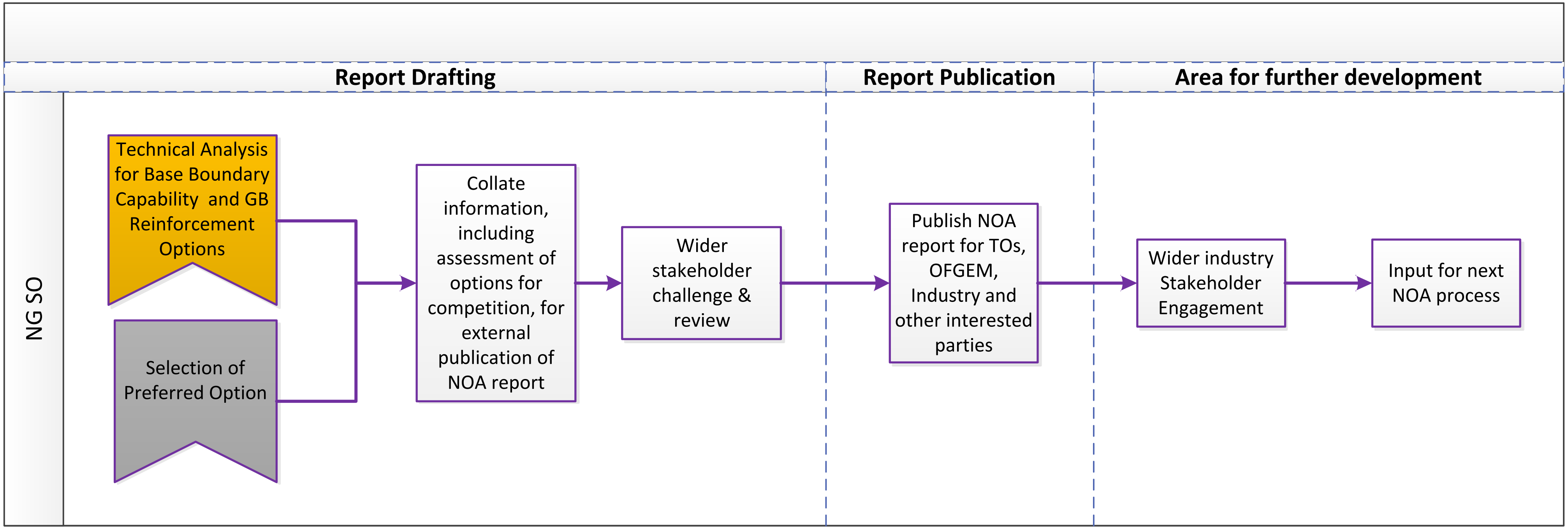


This diagram shows the overall NOA process. The text in each box corresponds to the descriptions of the stages at the top of the diagrams on the next pages. The process headings can also be found in the main methodology.


Collect Input
Identify future transmission capability requirements
Identify future transmission solutions
SPT and SHE Transmission
NG TO
NG SO
Identify Scottish onshore reinforcement options
Boundary reinforcement adjacent to other TO
Yes
Joint approach to identify reinforcement options
Technical Analysis for Base Boundary Capability and Reinforcement Options (SRF for Scotland)
No
Identify E&W onshore reinforcement option
Boundary reinforcement adjacent to other TO
YES
Joint approach to identify reinforcement options
NO
Identify GB offshore reinforcement options
Identify commercial & operational options for GB
Base Capability from previous year ETYS/ NOA
Future Energy Scenarios
Peak Y Boundary Transfer Model setup
Run Peak Y Boundary Transfer Model to identify required transfers
Stakeholder engagement on draft System Requirement Forms (SRF)
Issue System Requirement Forms (SRF)
Receive System Requirement Forms
Undertake validation and operability checks
Technical Analysis for Base Boundary Capability and Reinforcement Options (SRF for E&W)


Build GB Model
Boundary capability assessment for options
SPT and SHE Transmission
NG TO
NG SO
Scottish Models for Year 1-5, Year 7 and Year 10
Schemes information for Load and non-load related projects
Future Energy Scenarios
Build GB Models
Study Scottish current (Year 1) boundary capabilities
Maximum base boundary capability (MW), critical trip and limiting circuit
SRF for Scotland
Study Scottish future years 4, 5, 7, 10 boundary capabilities
Identify Scottish onshore reinforcement options
Determine incremental capabilities for reinforcements
Are there sufficient options to cover all scenarios?
No
Yes
Internal Challenge & review
Options Report
System Requirement Forms return
Joint approach to identify reinforcement options
Regional Challenge & review for common boundaries and reinforcement options between NGET, SPT and SHET
Identify E&W onshore reinforcement option
Identify commercial and operational options
Identify GB offshore reinforcement options
Study E&W current (Year 1) boundary capabilities
Maximum base boundary capability (MW), critical trip and limiting circuit
SRF for E&W
Study E&W future years 3, 5, 7, 10 boundary capabilities
Determine incremental capabilities for reinforcements
Are there sufficient options to cover all scenarios?
YES
Internal Challenge & review
Options Report
Cost Benefit Analysis
Report Drafting


Cost benefit analysis
Selection of preferred option
SPT and SHE Transmission
NG TO
NG SO
Capital cost for reinforcement option
Capital cost for reinforcement option
Boundary capability assessment for options
Constraint Model Setup
Consider additional reinforcements
Constraint Assessment run for all regions
YES
Is the constraint cost too high?
No
Least Worst Regret Analysis
Identify preferred network option(s) and note them
Assess against competition criteria
Stakeholder engagement and Challenge & Review
Changes in the reinforcement assumptions? (e.g. EISD, dependencies, capabilities)
NO
Report Drafting

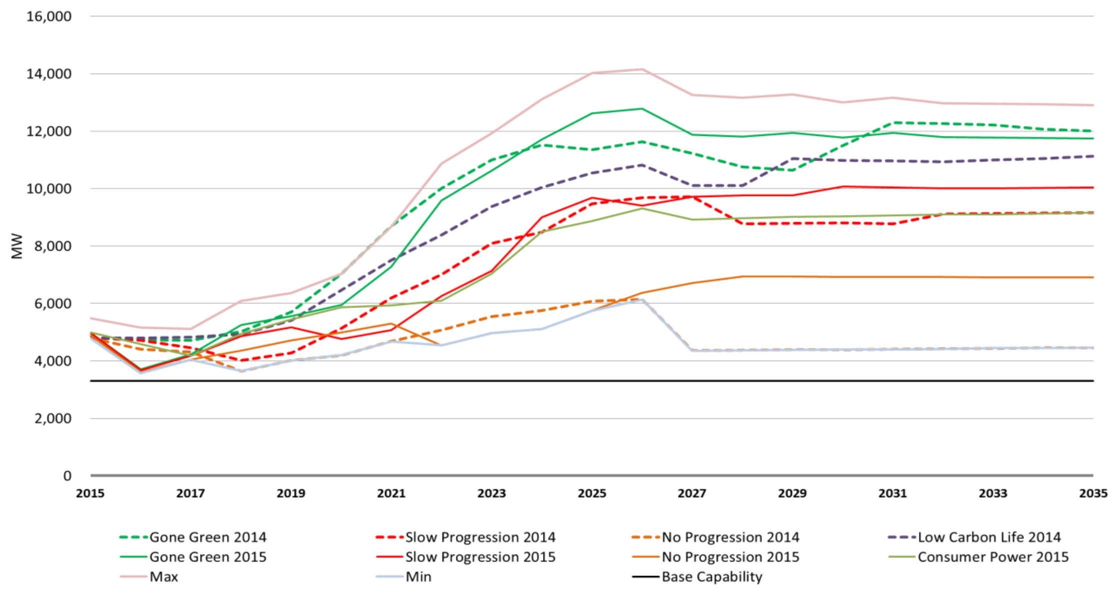

Report Drafting
Report Publication
Area for further development
NG SO
Technical Analysis for Base Boundary Capability and GB Reinforcement Options
Selection of Preferred Option
Collate information, including assessment of options for competition, for external publication of NOA report
Wider stakeholder challenge & review
Publish NOA report for TOs, OFGEM, Industry and other interested parties
Wider industry Stakeholder Engagement
Input for next NOA process

Appendix D: System Requirements Form Template

Boundary B6

Requirement proposer:
Passed To / Date: -
Boundary under Analysis: B6

Boundary Required Transfer Summary:



	Economy	Secured event	2016/ 17	2017/ 18	2018/ 19	2019/ 20	2020/ 21	2021/ 22	2022/ 23	2023/ 24	2024/ 25	2025/ 26	2026/ 27
See Note 1	Gone Green Winter Peak Required Transfer (MW)												
	Slow Progression Winter Peak Required Transfer (MW)												
	No Progression Winter Peak Required Transfer (MW)												
	Consumer Power Winter Peak Required Transfer (MW)												
See Note 2	Gone Green Winter Peak Intact Boundary Capability (MW)												
	Gone Green Spring / Autumn Intact Boundary Capability (MW)												
	Gone Green Summer-max Intact Boundary Capability (MW)												
	Gone Green Summer-max Outage Boundary Capability (MW)												

Note 1: Required Transfers in accordance with NETS SQSS Chapter 4 Economy Background.
Note 2: Boundary Capabilities derived from modification of the Economy Background, with secured events as per NETS SQSS.

Assumed Annual Duration of Planned Boundary Outage: *TBC* boundary outage days per annum

	Security	Secured event	2016/ 17	2017/ 18	2018/ 19	2019/ 20	2020/ 21	2021/ 22	2022/ 23	2023/ 24	2024/ 25	2025/ 26	2026/ 27
See Note 3	Gone Green Winter Peak Required Transfer (MW)												
	Slow Progression Winter Peak Required Transfer (MW)												
	No Progression Winter Peak Required Transfer (MW)												

	Consumer Power Winter Peak Required Transfer (MW)												
See Note 4	Gone Green Winter Peak Boundary Capability (MW)												
	Gone Green Spring / Autumn Boundary Capability (MW)												
	Gone Green Summer-max Boundary Capability (MW)												

Note 3: Required Transfers in accordance with NETS SQSS Chapter 4 Security Background
Note 4: Boundary Capabilities derived from modification of the Security Background, with secured events as per NETS SQSS.

Boundary Power System Analysis Summary:

Reinforcement options:

To satisfy the indicated future system requirement the following reinforcement options are suggested:

Option 1: **Ref number:** *Reference number if available*	Confidentiality (R/A/G)
Option Name: *Insert the name of the proposed reinforcement.*	G
Target boundary or boundaries: *List the boundary or boundaries that the option is to reinforce*	
Status: Same/Changed/New	
Description: *Provide a description of the physical nature of the reinforcement sufficient to allow power system modelling and costs to be developed.*	
Diagram: *Put diagrams here of how the new configuration will look including circuits and substation layouts.*	
Solution: *Describe how the proposed solution is intended to increase capability and under what conditions.*	
Lead engineer: *Contact name in case of queries*	

Scheme # (England and Wales TO only): *All relevant or create a new reference if none already exist*		
EISD: *Year*		
Circuit(s) out: *List the circuit outages that are needed for the option*	Outage duration: *List the duration of the outages*	

NOA Description: *Description of the option suitable for public presentation*	G
Actual Capability Increase: *The studied capability increase of the option. Add extra boundaries if the option reinforces more than one boundary.*	
Current Status: *Scoping, Delivery, etc (see Table 2 for descriptors)*	
Environmental impacts and risks: *Provide views on the environmental impact of the options depending on current status of project*	
New and existing assets - description of new assets and existing assets to be used in this option: *NOA requirement for competition and whether and how much of the option has new or complete replacement as opposed to refurbished or reconfigured existing assets*	
Separability: description of how any assets would connect to the existing network: *NOA requirement for competition – separability criteria. Assets might be teed to an existing overhead line, connect to a substation bay via a circuit breaker and busbar selector*	

isolators or in some other design	

Notes:

- Red is required text.
- The TO enters Red/Amber/Green (R/A/G) in the 'confidentiality' column on the table above. The SO treats confidential information as below. Where the data item cannot be confidential, the cell is already marked 'G'.

Green (G): May be shared with the public via the NOA report or informal exchanges

Amber (A): May be shared between the TOs and Ofgem through e-mails or informal conversation

Red (R): May not be shared with anyone outside of the SO or Ofgem.

- Please provide justification for marking any of the submitted data as "Red (R)" in the confidentiality column in the text box below

Justification for restricting use of data

Option 1 costs profile (based on current year costs)

	Spend to date	2017 /18	2018 /19	2019 /20	2020 /21	2021 /22	2022 /23	2023 /24	2024 /25	2025 /26	2026 /27	2027 /28	2028 /29	2029 /30	2030 /31	2031 /32	2032 /33	*	*	**Total**
Pre-construction																				
Construction																				
Total																				

Ongoing maintenance costs (on request from SO and where relevant)	

Breakdown of construction costs	
Substation works	£m
OHL works	£m
Cable works	£m
Compensation plant	£m
Special plant	£m
Other (state but to include project engineering costs)	£m
TOTAL	**£m**
Cost accuracy (where appropriate – for early development options assume ±50% cost accuracy)	£m

Delay costs (on request from SO and where relevant)		
Event or stage	**2017/18**	**2018/19 after making progress in 2017/18**
Demobilisation		
Ongoing		
Remobilisation		
Reconsenting		
Cancellation		

Notes:

- Spend to date column in the last year if possible and inflation adjusted for the current year. Please state the year this is costed in.
- Use the columns marked * for mid-life refurbishment costs.
- The costs table covers for when a project is delayed or cancelled now and delayed or 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.

Appendix E: Form of the Report

The System Operator (SO) 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

Executive Summary

Contents Page

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.

The chapter will give stakeholders an overview of options to meet electricity transmission system reinforcement needs and the SO's view of the preferred options. It will reiterate that the final investment decision rests with the TO.

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 Reinforcements. We will include a description of how the SO 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: Boundary Descriptions

The purpose of this chapter is to give an overview of the boundaries that make up the GB electricity network. This will comprise of a short paragraph introducing the boundary and the boundary's network map. It will refer the reader to the ETYS Chapter 3 Network Capacity and Requirements for details of the future capability requirements for each boundary.

Chapter 4: Proposed Options

The purpose of this chapter is to describe the options that the SO has assessed. The description will include the status of an option (see table 2 in the main methodology) and a general overview. The description will also identify each option as build or reduced-build and depending on the maturity of the option might include summaries of the technical, environmental, operability and deliverability aspects of the work. Where there are system security requirements for the boundary (in addition to economic), the chapter will highlight this.

Chapter 5: 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 chapter will then give the regret values for the options and combinations of options where the options are critical – that is needing a decision to proceed imminently. Chapter 5 will detail the SO recommendation whether or not 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 assess the options against the competition criteria and indicate those that are likely to meet the criteria. The secondary legislation defining the new, separable and high value competition criteria will be subject to Parliamentary scrutiny. The chapter will describe the criteria once they are settled.

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 SO 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.

Chapter 5 will meet the SO obligation to produce the Network Development Policy output for Incremental Wider Works.

Chapter 6: 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 7: 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 the spring 2016 customer 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

Appendix F: Summary of Stakeholder feedback

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

- Campaign to Protect Rural England
- National Grid TO
- Ofgem
- SHE Transmission
- Smith Institute for Industrial Mathematics and System Engineering
- SPT
- Transmission Investment

Area of Feedback	Feedback	SO response
Competition	Providing further clarity and detail	Further clarity and detail have been provided throughout the report in the requested areas. The extent of the SO's role in performing the technical analysis is still under discussion. More detail has been provided on the how the SO will nominate projects for competition and the relevant legislation that will define this further.
Consents	Use of terminology	This has been accepted and changed
Cost Basis	Clarification of meaning	Use of this term has been clarified and text has been added
Costs	Clarification and further detail with the scrutiny of costs	The SO's role has been clarified however the process for scrutiny will be discussed further.
Environment	Further information on the SO's approach	This area is mainly outside the NOA Report methodology's remit. We are reviewing whether the document is subject to Strategic Environmental Assessment (SEA) requirements.
Gone Green	Clarification of how Gone Green is used	Further clarity of how Gone Green scenario is used and how the SO ensures that no one scenario skews results is described in the report. Also information provided on the future development of probabilistic tools.
Interconnectors	Clarification of terminology and assumptions	Further clarification and detail now provided in the suggested areas
NOA Process Study	Amendment to study descriptions	Applied in Appendix A. One area of our economic analysis has been discussed outside the methodology.
Security	Definition and Application of the Security Criterion	The Security Criterion is defined in the SQSS and any changes to its definition would go through the usual SQSS modification process. This description of how it is applied has now been included.
SRF Format	Submission of diagram data and RSPI	The SO wants to request no more data than necessary, and the provision of further diagrams from the TO to the SO, although helpful, would not add significant value for the SO's modelling purposes. The areas of RSPI are still under discussion between SO,

		TO and Ofgem.
Validation	Three areas of feedback requesting more detail to how and when the SO validates	This requests have been fulfilled and submitted as part of Appendix B

Network Options Assessment for Interconnectors

Interconnectors Welfare Benefit Assessment Methodology for ITPR Year 2

July 2016

Version	**Final 2.0**
Date	**27th July**

About this document

This document contains National Grid's Network Options Assessment (NOA) methodology for assessment of interconnectors established under NGET Licence, Licence Condition C27 in respect of the financial year 2016/17. It covers the methodology on which NGET in its role as SO will base the second NOA for Interconnectors report which will be published by 31 January 2017 as a chapter of the NOA report. National Grid's experience and stakeholder feedback has informed the development of this methodology. The methodology statement has been revised for the second NOA for Interconnectors and will continue to be on an enduring basis as required by Licence Condition C27.

Contents

1. Overview

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 (NETS SQSS) and the development of efficient interconnector capacity. Interconnectors with other European markets will increasingly play an important role to achieve this goal.

1.2 This document provides an overview of the aims of the NOA with respect to interconnectors and details the methodology which the System Operator (SO) will adopt for the analysis and publication of the second NOA report (to be published by 31^{st} January 2017). The SO shall undertake a more detailed, expansive analysis for NOA for Interconnector's second iteration. Furthermore, since the publication of the first methodology, the SO has undertaken procurement of a new Pan European Market Model, BID3. This enhances the capabilities of the SO, but also creates risk associated with the introduction of a new tool. The uncertainty created by this risk and an approach to mitigate this is reflected in the document.

1.1. Structure of the Document

1.3 This document consists of the 5 chapters listed below:

<u>Criteria for selection of interconnection capacity</u>

This chapter contains a justification of the factors to be considered in the determining whether additional capacity would be beneficial.

<u>Cost estimation for interconnection capacity</u>

The costs associated with an interconnector and how these will be forecast is outlined.

<u>Components of Welfare Benefits of Interconnectors</u>

The concept of Social Economic Welfare in relation to interconnection, and the components of this value, is explained.

<u>Models employed by the System Operator</u>

A description of the SO's current market modelling capabilities is given

<u>Interconnection Assessment Methodology</u>

A description of the method by which the SO proposes to meet the aims of NOA in relation to optimal interconnection capacity is provided.

2. Criteria for selection of interconnection capacity

2.1 There are multiple criteria that could be considered when evaluating interconnector projects. The foremost are Social Economic Welfare, described in detail in section 4, capital costs and impact on constraint costs.

2.2 The impact on constraint costs is associated with the connection location of an interconnector. Changes in the total System Operator expenditure spent on balancing the system are then highly dependent on flows local to that connection point. They can thus only be quantified for specific projects- that is, a particular capacity connecting within a particular network area. To give a general picture on which network areas are best able to accommodate new interconnectors (or will be in the future following reinforcements) the ETYS and NOA reports provide information on the current state and ongoing development of the onshore network. This is done through the quantification of boundary limitations, and the presentation of recommended options for reinforcement of the grid. This is intrinsically linked to the increasing presence and geographical spread of interconnection in the UK- as further interconnectors apply to connect to NGET, these will in turn place further (forecast) strain on boundaries and potentially trigger investment in reinforcements (if the NOA process determines that to be the most economical and efficient course of action). This methodology thus prioritises providing a market based view of optimal interconnection. As the market responds to this and other intelligence with potential projects, the FES view of interconnection will change or remain the same accordingly; this will drive the ETYS view of necessary reinforcements in future years.

2.3 Two 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 contribution or detriment to meeting GBs 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.

- Carbon costs: both 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. The interaction of emissions and welfare with the European Trading System in carbon may reduce the apparent impact of interconnection directly on emissions; further analysis and commentary in the report should explain this effect.

- RES integration: both modelling facilities (as described in section 5) 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.

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

- Operational costs: Various costs associated with the day-to-day operation of the interconnector, and the maintenance of its components, are neglected in the analysis. This is driven by the complexity of defining these costs, per market, for little to no potential improvement in the solution. 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.

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

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

- Ancillary service benefits: A major consideration is the ability of interconnectors to provide services which enhance system operability. This could potentially benefit both the interconnector owner, with additional income streams, and the consumer, by increasing system security or lowering the cost of providing system security. This is evaluated on a project-by-project basis as part of the Cap and Floor mechanism, so again is excluded here. More information on ancillary service provision, and interconnectors’ potential contribution to this, is available in the System Operability Framework (SOF).

2.5 SEW and CAPEX are the most significant criteria, in addition to being reasonably straightforward to quantify, so will be used as the determinants of capacity fitness (that is, whether an increase in capacity is beneficial).

3. CAPEX estimation for interconnection capacity

3.1 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 problematic - fortunately, exercises 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 recent report by ACER [1] provides sufficient granularity to differentiate between standard costs of connection to different markets, the variation driven mainly by the average necessary subsea cable length. This will be defined by estimating the furthest and shortest realistic subsea cable and onshore overhead line lengths from the market under consideration to GB, using engineering judgement and substation locations on each network. Onshore works to reach the nearest substation will all be assumed as double circuit 400kV overhead lines. An assumption of one cable per 500MW will be made- this matches the granularity of the search and is realistic, based on existing infrastructure. The convertor station assumed value is drawn from an averaging of known CSC and VSC projects performed by ACER. The ACER cost estimates are shown in the table below:

Table 1 Standard costs

Total cost per route length (km)	Mean (€, 2014)	Min-max interquartile range (€, 2014)	Median (€, 2014)
DC cables	757,621	705,293 – 791,029	760,284
OHL	1,060,919	579,771 – 1,401,585	1,023,703

Total cost per rating (MVA)	Mean (€, 2014)	Min-max interquartile range (€, 2014)	Median (€, 2014)
HVDC convertor station	87,173	76,030 – 103,566	76,923

3.2 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 SO (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 of 3.5%. Additionally, the cost of capital is taken account of through the use of a Weighted Average Cost of Capital of 6.8% for Interconnectors, drawn from a publically available Grant Thornton report.[1]

3.3 An explanation of how WACC and discount rates are used by the SO to obtain a Present Value is in Appendix 1, which describes how Spackman analysis is employed.

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

4. Components of Welfare Benefits of Interconnectors

4.1. Introduction

4.1 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 an interconnector.

4.2. Social and Economic Welfare

4.2 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 Europe wide SEW values, and the components which make up each. Europe wide SEW is the optimised value in the NOA for Interconnectors.

4.3 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 an 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.

4.4 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 NOA for Interconnectors assessment, as discussed in the previous section.

4.3. Effects on Interconnected Markets

4.5 Power flows between two connected markets is driven by price differentials. Figure 1 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 in B power will be transferred from A to B.

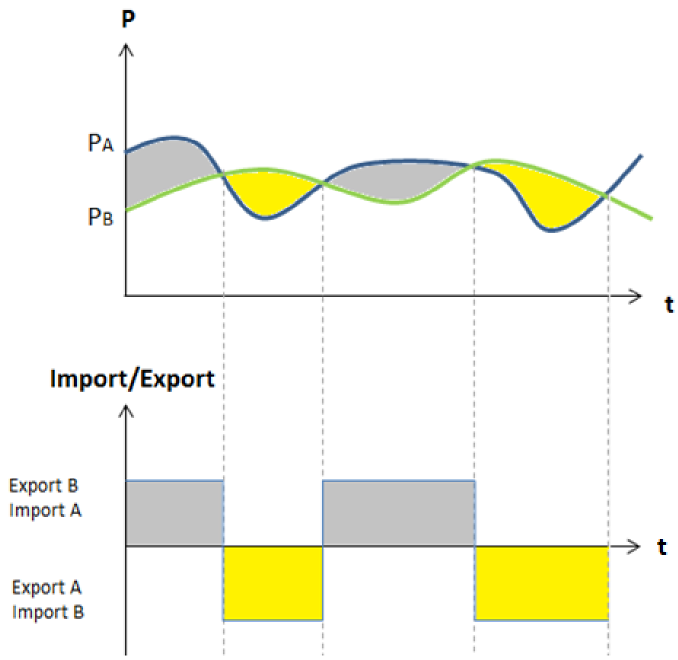


Figure 1 Price difference as import and export driver

4.6 Figure 2 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, now able to compete with generators in B, are likely to be forced by competitive pressures to reduce their costs, which might 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.

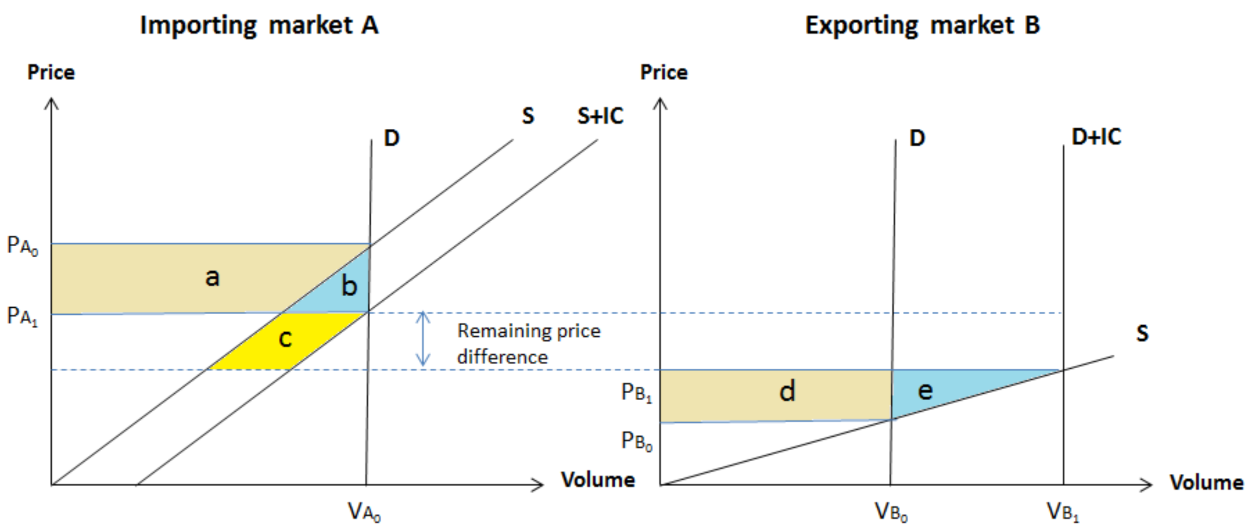


Figure 2 Consumer and Producer Surplus of connected markets

4.7 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 2 shrinks.

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

4.9 The Global SEW is the sum of the welfare of 5 parties (GB & Europe consumers, GB & Europe producers, 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.

4.10 Where the market is modelled with and without some additional interconnection capacity added, Socio-Economic Welfare 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%.

5. Models employed by the System Operator

5.1 BID3 is the intended tool for performing the NOA for Interconnectors this year. As BID3 is new to the SO, and the necessary integration is ongoing, the SO's pre-existing tool, ELSI3, is being kept up to date such that it can be used in the event of the new system being unable to perform the process for any reason.

5.1. Electricity Scenario Illustrator 3 (ELSI3)

5.2 The market modelling tool that has been used until now by National Grid is called ELSI; it is used to forecast the constraint costs for different network states and scenarios. The newest iteration, ELSI3, is used for modelling European markets in addition to GB. It is an open source Excel based tool, developed in-house and made available to stakeholders to conduct their own constraint forecasting. The high-level assumptions and inputs used in ELSI3 are outlined in Table 2.

Table 2 Assumptions and input data for ELSI

Input Data	Current Source	Description
Fuel price forecasts	FES	20 year forecast, varies by scenario
CO_2 forecasts	Baringa	20 year forecast
Plant efficiencies and seasonal availabilities	Historical data	
Plant bid and offer prices	Historical data	Related to SRMC costs
Forecast system marginal prices for non-modelled overseas markets	Baringa	20 year forecast, varies by scenario and market
Wind data	Pöyry (historical)	Wind load factors for various zones around GB
Demand data	FES	MW annual peak and zonal distribution
Load duration curve	Historical data	2012/13 outturn data converted into ELSI periods
Maintenance outage patterns	Historical data	Maintenance outage durations by boundary

5.3 The model simulates 4 periods per day for 365 days per year (=1460 periods per year) and is set to simulate 20 years into the future. The primary output for the interconnectors' welfare benefit assessment process, particularly measured as consumer surplus, is the annual System Marginal Price (SMP) forecast.

5.4 ELSI3 is a zonal fuel type model. A distinction between generators of the same fuel type in the same zone is not possible. Therefore, output data, e.g. volumes of output (and thus costs), cannot necessarily be attributed to specific generators.

5.2. BID3

5.5 BID3 was procured to add market modelling capability to the System Operator, above and beyond that available in ELSI. The tool and associated hardware are in delivery at time of writing.

5.6 BID3 is a Pan European Market Model created by Pöyry. It offers improvements in accuracy and scope of modelling, featuring: working models of all ENTSOE countries; hourly time resolution; optimisation of plant operation over multiple periods (particularly with respect to thermal and hydro plants which have constraints on operating patterns); easy to use outputting populated with key indices such as congestion rent and consumer welfare; and several further modules for economic analysis not directly applicable to the interconnection issue.

5.7 In the summer of 2016, further development of the tool and benchmarking with ELSI built confidence and skill in deploying the model; this will allow its use in the autumn to perform key NOA work.

5.8 The introduction of a new tool to the NOA process creates risk - inexperience with the software could lead to incorrect setup of inputs, or misunderstanding of the results. While this risk has been mitigated to a degree through benchmarking and extensive training, a further measure is ensuring the NOA process is compatible with ELSI3, such that results can be checked with a software package that has been used previously and is trusted.

6. Interconnection Assessment Methodology

6.1. Optimisation of GB-Europe Interconnection Process

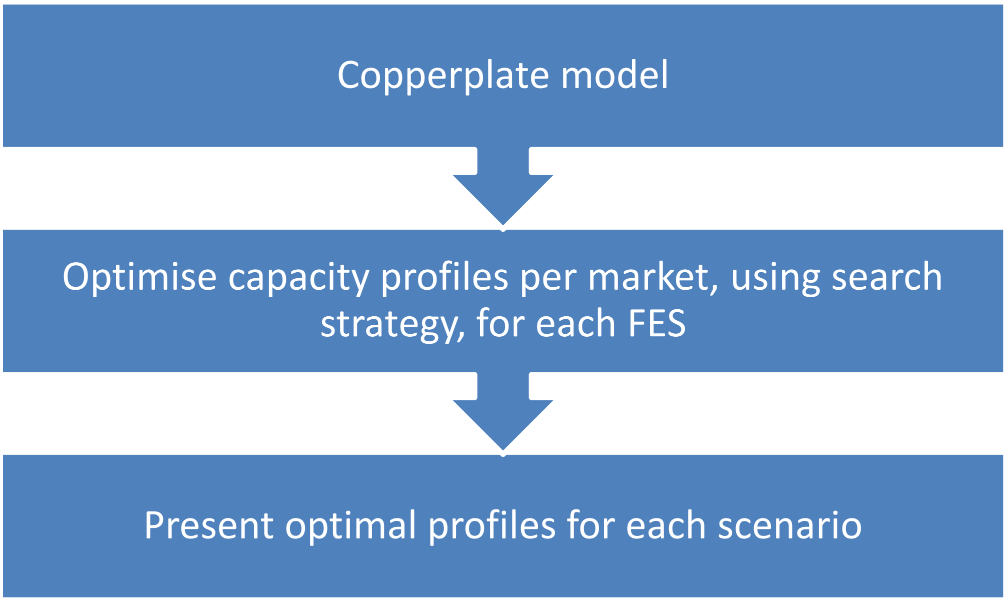


Figure 3 Process summary

6.1 The optimisation of future interconnection capacities is a multivariable search, maximising the SEW-less-CAPEX value. The decision variables are the total MW capacities (the sum of all interconnector transfer capacities) between GB and 9 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 nearest GB. The countries in question are: Iceland; Norway; Denmark; Germany; The Netherlands; Belgium; France; Spain; and Ireland (which includes the Republic of Ireland and Northern Ireland). The number of variables makes an exhaustive search within a useful timeframe infeasible - a search strategy must therefore be defined.

6.2 Not included in the search is the level of interconnection between the European markets. These levels will be fixed throughout per scenario (though could vary across future years) and initially defined by the SO based on ENTSO-E and NG forecasts.

6.3 To guide the search, upper limits to potential power transfers between markets is found using a copper plate network - this simulates flows between markets under the hypothetical situation of no physical limitations on energy exchange. Ignoring the multiple, complex physical problems that make long distance power transmission difficult and uneconomical means the flows found are usually much higher than practically possible. The flows between the markets that would occur under these conditions are then analysed to find a maximum necessary capacity size. This informs the search for optimal capacities, highlighting those capacities with potential for increase, and those with planned interconnection levels that already suffice for facilitating market driven flows. It's important to note that the maximum market driven flow is not identical to the optimal capacity, due to the effects of cannibalisation discussed in section 4.

6.4 The market studies, which model the physical limitations of transmission between markets (but not within markets) start from the future levels of interconnection that will arise from commissioned links, and future projects with a high degree of regulatory certainty; Eleclink, NEMO, IFA2, FAB Link, NSN, Viking, and Greenlink. These capacities are then adjusted to search for improvements on this initial point, represented by an increase in the global SEW-CAPEX value following the alteration of the capacity values. This global SEW-CAPEX value takes into account the whole study period, such that the overall timing of connection is assessed in addition to the capacities per market.

Copper plate study

- No network limitations within markets or between Europe markets and GB

Market studies

- No network limitations within markets, but MW transfer capacities imposed between Europe markets and GB

Figure 4 Differences between copper plate and market studies

6.5 To clarify the steps described, a worked example will be followed based on the hypothetical situation below, optimising (with example values) the capacities and optimal timing of connection for potential interconnections to the market under consideration:

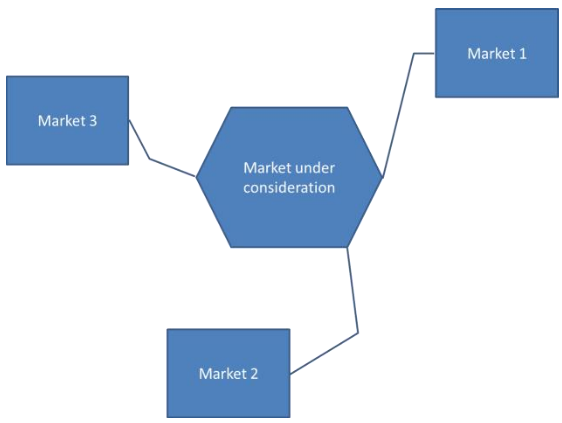


Figure 5 Example markets

6.6 For this methodology, capacity refers to the bidirectional capacity between two markets - this can be achieved through any number of interconnectors. A distinction must be maintained between the capacity before and after losses on interconnectors - that is, a 1000MW interconnector with the generic assumption of 2% losses actually transmits 980MW of useful power.

6.2. Modelling inputs

6.7 The starting point of the process is National Grid's Future Energy Scenarios (FES) which include generation plant ranking orders and demand forecasts for each scenario. FES are focussed on the GB market, however there will be some additional development work in BID3 to investigate the possibility of matching the assumptions in the European markets to those of each FES. Due to time constraints, those reinforcements recommended by this year's NOA cannot be included, as those recommendations will not be available until too late for the NOA IC analysis to be undertaken and reported within the time limits set by the licence condition. The ranking order for each scenario contains existing and planned / proposed interconnectors.

6.8 The FES make forecasts of the future interconnection capacities in GB, per scenario. An important distinction between the FES and this process, therefore, is that the NOA for Interconnectors aims to find what would be optimal, rather than what is currently likely to happen.

6.9 The time period considered in the studies extends from the present to 2035. This is to match the FES, which forecasts up to 2035 in detail. For the timing analysis, only capacity in years 2022, 2025, 2027 and 2030 will be investigated. The reason for not starting to analyse additional capacity until 2022 is this is deemed the soonest 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 runs as constrained by time limitations.

6.3. Copperplate model

6.10 The purpose of a copperplate model is to find the flows a link, or set of links, would experience if the various European networks were connected to GB by links of infinite capacity. The relative size of these flows then reflects the combined markets' optimal dispatch solution such that the cheapest possible set of plant is always that which meets demand. The flows on the country to country links thus show where the market dictates extra capacity would be useful. The size of capacities this model suggests will be erroneous due to loop flows and failure to consider inefficiencies of interconnectors; it does, however, reflect the relative usefulness of links to the various European markets and provide a starting point for a more refined search of potential capacities. Rather than using the maximum flow observed in simulation, a value will be taken that reflects the majority of the flows used, removing unrealistically high values that can be generated by a completely unconstrained model, fed by loop flows, and potentially the approach taken by the solver. In the example below, this was 80% of the flows modelled. This is referred to as a P80 value, and is not the value that will be taken for the process, which will depend on the results of the actual copper plate studies.

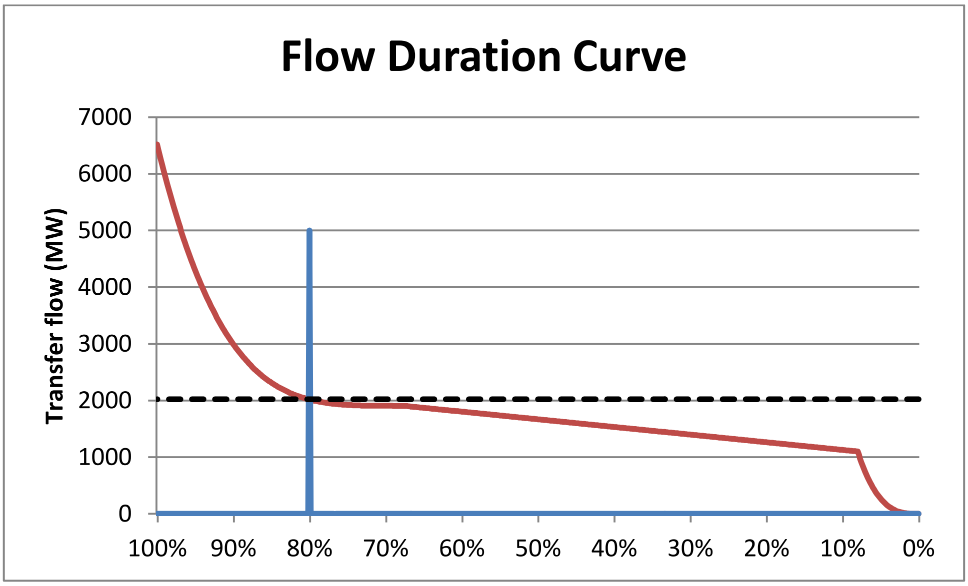


Figure 6 Example flow duration curve from copperplate simulation - for illustration only

6.11 In the example shown, the starting point for the capacity optimisation would be 2000MW, as 80% of the copperplate flows were less than this value.

Table 3 Example copper plate flows

	Copper plate flows		
	Max flow	P80	Rounded P80
Market 1	4426	3562	3500
Market 2	3214	2612	2500
Market 3	4112	3170	3250

6.4. Market Modelling

6.12 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, 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. A balance between computing resource and rigour in each step of the process must be struck. An example step is outlined below, wherein multiple capacity changes are evaluated for SEW in each step, and that capacity change which yielded the best result is kept in the next step. Note that engineering judgement could be employed to avoid searching solutions which are deemed unlikely to yield high SEW – CAPEX results. This neglect of search steps would be subject to meeting two conditions: a reasonable justification for the assumption it would not have a high [SEW - CAPEX] value, and it's inclusion in the modelling must cause an undesirable strain on modelling resources.

6.13 Timing of capacity increases can affect the SEW generated by the interconnection across the study window. Within each search step, therefore, timing combinations should also be checked (for example, testing the commissioning of an extra 500MW in 2022 and 2025 to determine which is preferable). Again, this is subject to the need to only check realistic permutations within the search to allow the convergence of an answer within reasonable timescales. The use of spot years would be necessary to allow a solution to converge, wherein the commissioning of additional projects would be evaluated only in future years 2022, 2025, 2027 and 2030. The table below does not show the inspection of different years of commission for clarity- there would be 12 rows in reality, to reflect the 3 markets increasing capacity in four different years.

Table 4 - Example of iterative search step

	Iteration 1 Transfer Capacities (MW)						
		Simulation 1		Simulation 2		Simulation 3	
	Baseline	Increment	Simulated value	Increment	Simulated value	Increment	Simulated value
Market 1	2000	+500	2500	0	2000	0	2000
Market 2	1000	0	1000	500	1500	0	1000
Market 3	1000	0	1000	0	1000	500	1500
CHANGE IN SEW - CAPEX	**0**	**+ £7M**		**+ £3M**		**+ £11M**	
	Iteration 2 Transfer Capacities (MW)						
		Simulation 1		Simulation 2		Simulation 3	
	Baseline	Increment	Simulated value	Increment	Simulated value	Increment	Simulated value
Market 1	2000	+500	2500	0	2000	0	2000
Market 2	1000	0	1000	500	1500	0	1000
Market 3	**1500**	0	1500	0	1500	500	2000
CHANGE IN SEW - CAPEX	**0**	**+ £6M**		**+ £2M**		**+ £5M**	

6.14 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. The optimal capacity profiles will then be presented in the NOA report, providing the industry not with a single recommendation, but a range of optimal capacities against each of the FES, with which to judge where the best opportunities for further interconnection lie.

7. Process Output

7.1 The above methodology will be employed to create a chapter of the NOA 2017 report. This chapter will present the main findings of the analysis - per scenario, an optimised interconnection capacity level by market, and the best timing for capacity increases. It will include commentary on these results and other impacts of interconnection excluded from the optimisation. This will be delivered by 31st January, 2017.

Appendix A: Spackman Analysis

Applying the Spackman Approach to Project Capital Costs

The Spackman approach is the standard approach used by National Grid for determining the Present Value (PV) of project Capital Expenditure (CAPEX) costs.

A helpful summary of the approach is outlined in the following publically available document:

http://www.ofwat.gov.uk/aboutofwat/stakeholders/jrg/pap_tec201207jrgdiscount.pdf

It has been accepted by Ofgem for use on a range of capital investment projects undertaken by National Grid. Its focus is on how discounting should be applied in the case where private finance drives an investment but the benefits accrue to consumers.

In the Spackman methodology the financing or CAPEX costs are converted into annual payments (in other words mortgaged over the economic life of the project) using a fixed annuity factor determined by the firm's projected WACC. The resulting fixed flow of annual costs is then discounted in the usual way using the standard discount rate (in this case the Treasury Green Book Social Time Preference Rate (STPR) of 3.5%).

The benefits are also discounted in the normal way using STPR; there is no change here.

To illustrate the methodology, below is an example where the CAPEX is £100m and is incurred in full in 2022/23.

1) We divide £100m by the annuity factor to determine the annual payments (annuity) over the projects life.

   The annuity factor here is: $\sum_1^i (1 + WACC)^{-i}$; where i= 25 years

   So for a WACC of 6.8% this is £8.43m per year for 25 years.

2) For each year we determine the PV of the annuity payment in the usual way by multiplying the payment amount by the discount rate.

   The discount rate is: $(1 + STPR)^{-i}$; where i= 25 years.

   As each year goes by the PV of the annuity decreases as you would expect.

3) Finally we sum the PV of the annuities per year to give a PV of the total cost. This equates to £91.95m in this case.

SO Process for Input into TO Led SWW Needs Case Submissions

nationalgrid

System Operator

September 2015

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Date	**29 September 2015**

About this document

This document contains National Grid System Operator's proposed methodology for inputs into TO led Strategic Wider Works submissions. The methodology responds to the new requirements for the SO as part of the NOA process, as outlined in Licence Condition C27 in respect of the financial year 2015/16.

SO Process for Input into TO Led SWW Needs Case Submissions

Contents

Strategic Wider Works Overview

1 RIIO-T1 identified large transmission projects, which strengthen or extend the electricity transmission system, as wider works outputs. These are triggered by a need to increase the capacity of the network or to extend the network to accommodate new generation and lead to economically efficient transmission of electricity in the GB, as well as comply with network security standards.

2 Ofgem's Guidance on the Strategic Wider Works (SWW Guidance)[1], which was published in October 2013, states that there was uncertainty around the timing and cost of some large transmission projects at the time of finalising RIIO-T1. The document suggests this was predominantly due to extent of these projects' dependency on the level of future generation. Considering the scale of the investments involved the SWW Guidance states that the potential impacts of this uncertainty on GB consumers could be significant.

3 The SWW Guidance states that to help manage this uncertainty, flexible Strategic Wider Works arrangements were included in RIIO-T1 to consider large transmission projects when more information was available to inform decisions on whether the investment is in the interests of existing and future consumers.

4 The detailed process regarding the Strategic Wider Works (SWW) arrangements for the Transmission Owner (TO) is presented in the SWW Guidance. However, it is worth noting that the process involves approvals from Ofgem at three distinct stages:

a. Eligibility: To be eligible, the proposal must meet pre-defined criteria including the level of the expected cost and outputs it is expected to deliver. Further details on the criteria and the information required for eligibility assessment is presented in the SWW Guidance. If the project is eligible for assessment, Ofgem will initiate the review of the Needs Case submission, as set out below.

b. Needs Case[2]: The purpose of the Needs Case document is to present technical and economic rationale and necessary evidence to underpin the choice of the preferred option compared to a credible range of alternative solutions. Hence, as part of the review of the Needs Case, Ofgem seek to review the TO's appraisal of technical need and cost benefit assessment across a range of solutions and credible scenarios, which may be based on different factors in relation to generation, demand, fuel price forecasts, renewable subsides, etc. Furthermore, Ofgem seek for evidence on the optimal delivery date of the preferred option. Through this review, Ofgem seek to ensure that, given the range of uncertainties, the preferred solution

[1] Source: www.ofgem.gov.uk

[2] Projects which are already in the Transmission Owner's RIIO-T1 Business Plan are envisaged to have their eligibility outlined. Hence, such projects are likely to progress straight to the Needs Case stage.

offers the best long-term value for money for existing and future GB consumers. In most cases, ahead of making any decisions, Ofgem seek to consult stakeholders on their initial views on the Needs Case.

c. Project Assessment: The purpose of the Project Assessment is to present more in-depth evidence on the preferred option and demonstrate the TO's readiness to proceed with the project. There may be some overlap between Ofgem's reviews of the Needs Case and the Project Assessment. In particular, as part of the review of the Project Assessment Ofgem assess whether the TO has developed a robust development plan and risk management arrangements to deliver the project efficiently. Ofgem also review whether the technical plans of the preferred solution are sufficiently advanced to assess the efficient costs and specify a new SWW output. To inform their final decision on the proposal Ofgem will consult stakeholders on the detailed Project Assessment and their views on the SWW output and costs.

5 In addition to the three formal stages, there are ongoing discussions between the TO and Ofgem. Historically, the System Operator (SO) has not been involved in such discussions. Furthermore, in the past the SO has predominantly submitted responses to Ofgem's consultation on specific projects seeking SWW approvals. Although the SWW arrangements continue to be a TO led process, the Network Options Assessment (NOA) process introduced through ITPR seeks to increase the SO's role. Within this context, the purpose of this document is to outline the process and arrangements that will exist between the SO, TOs and Ofgem where the SO will provide input into TO led Strategic Wider Works Needs Case submissions.

6 This document has two distinct components:

a. To provide a high level overview of the general process from initiation to conclusion of Strategic Wider Works arrangements and the SO's role in this wider process; and

b. To provide a detailed Cost Benefit Analysis (CBA) Methodology, which is the SO's principle contribution to TO led Needs Case submissions[3].

7 It is important to note that whilst the CBA undertaken by the SO will lead to recommendation of a preferred, most economically efficient, option to meet the system needs, any investment decision will remain with the TOs. Also note that the process summarised in this document, particularly regarding the SO's role in the CBA and the wider SWW process, reflects the default position for a typical network reinforcement project seeking approval through the SWW route.

8 Projects with more bespoke requirements may require a different approach, which would be developed and agreed though joint working between the respective TO and the SO, and subsequently presented to Ofgem for approval prior to commencing the

[3] Please note that this is the default SO role for typical new projects. Details regarding SO's activities for existing projects at different levels of development are also outlined later in this document.

preparation of the SWW Needs Case. This may include analysis other than CBA, for example, system operability.

9 Furthermore, the content of this document is based on the current process outlined in the SWW Guidance. We understand that the existing SWW process is currently being reviewed. As this process changes, the contents of this document may need to be refreshed.

Strategic Wider Works Process and the SO's Role

10 The process for SWW Needs Case and Project Assessment development from start to submission consists of various sequential activities. The text below outlines these activities and the SO's role across them for typical new projects seeking necessary SWW approvals for investment on the transmission network. By the nature of the activities outlined, the SO's role in the SWW process will be to provide the necessary support to the TOs and Ofgem in their respective decision making processes.

11 There are considerable linkages between the annual NOA Report process and the SO's role in the wider SWW process. These are also captured in the relevant steps outlined below.

12 **Step 1: Identification of the system need**. This could be achieved through the following channels.

a. SO assesses the system need through an annual Electricity Ten Year Statement (ETYS) process, which subsequently informs the NOA Report. The analysis may result in the SO requesting the TO to consider initiating the preparation of a SWW Needs Case.

b. SO and TOs regularly discuss and review network capacity issues and the need for SWWs in a particular TO's area at Joint Planning Committee (JPC) meetings. The SO may request the TO to consider initiating the preparation of a SWW Needs Case.

c. SO may request the TO to consider initiating the preparation of a SWW Needs Case, based on any new information which SO and / or TO may have obtained (e.g. updated information regarding certain customer connections).

13 Following the trigger, the SO will engage with the TO to understand the context of the project, particularly if such discussions haven't already been undertaken as part of the NOA Report process or the JPC. In addition to understanding the project's background, the discussions will seek to establish whether the project demands a different approach on SO's wider role and the CBA, to those identified in this document, due to any non-typical requirements. If yes, the SO and TO will work together to develop the bespoke approaches, as necessary.

14 Another key outcome of this meeting will be development of an issues log, which will be jointly maintained by the TO and SO throughout the project. This may be required to be shared with Ofgem at any stage of the SWW process.

15 **Step 2: Evidence for Eligibility Assessment**[4]. The TO prepares the evidence for eligibility assessment to provide confirmation to the SO that the works required are Strategic Wider Works. The TO engages with Ofgem to share the evidence prepared for the eligibility assessment for initial feedback. The TO may seek the SO's support to prepare the required evidence, as necessary.

16 **Step 3: Ofgem's Eligibility Assessment**. Upon receipt of the Eligibility Assessment, Ofgem will review whether the project is eligible and meets the qualification criteria. Ofgem may wish to consult the SO at this stage. If the project is eligible for SWW, Ofgem will confirm this to the TO.

17 **Step 4: SO's initial recommendations for a range of scenarios**. The SO makes initial recommendations to the TO regarding the range of scenarios which should be studied for the Needs Case submission.

18 **Step 5: Agree the range of scenarios (SO and TO)**. Through discussion, the SO and TO agree a range of scenarios required to be assessed as part of the Needs Case submission[5]. The TO may wish to study additional scenarios, beyond those agreed with the SO[6]. The TO engages with Ofgem to share the evidence prepared for the choice of scenarios for the Needs Case submission and seek initial feedback.

19 **Step 6: Agree the counterfactual (SO and TO)**. The TO and the SO discuss and agree the definition of the counterfactual state for the network boundaries under consideration as part of the Needs Case. The counterfactual for typical projects is 'do nothing'. If, due to the bespoke nature of the project considered, the definition of the counterfactual requires further considerations, the SO and the TO will engage with Ofgem with appropriate evidence for feedback on this issue, early in the assessment process.

20 **Step 7: Options Development (refresh / update)**. Based on the identified system need, the TO develops options to meet this requirement. This includes an assessment of the:

i. boundary capability increase associated with each solution;

[4] Projects which are already in the TO's RIIO-T1 Business Plan, will progress directly to Step 4.

[5] For projects, where the TO has already initiated the development of the SWW Needs Case, the project historic background may influence the discussions between the SO and the TO, and subsequently the choice of scenarios and requirements for any further analysis (as necessary).

[6] If there is disagreement between the SO and the TO on choice of scenarios, the issue will be recorded with appropriate evidence within the issues log. The TO may wish to look at additional scenarios outside of this process. In the near future, as the SO continues to use an open source model, the SO will share the model with the TO to undertake any simulations for additional scenarios. Once the SO has procured a new model, the SO may need to simulate the additional scenarios on TO's request. However, depending on the SO's rationale on non-inclusion of these additional scenarios, the relevant scenarios may not feature in the CBA report prepared by the SO.

ii. earliest in deliver dates of the solutions developed;

iii. forecast capital expenditure of the solutions with relevant spend profiles, estimates of any significant asset refurbishment works (cost and timing);

iv. asset life span in the developed solutions; and

v. deliverability considerations as identified in the NOA Report methodology.

21 Please note that the TO would have already developed a range of options ahead of initiating the preparation of the Needs Case. They may also feature the respective year's NOA Report. At this stage the TO may need to refresh the network analysis based on the scenarios agreed as part of Step 5.

22 **Step 8: The SO reviews the options**. Consistent with the NOA Report process, the SO's review process will ensure that the TO has considered a credible range of options to meet the system need. This will also include testing system operability of the options, particularly for options (or scenarios) which have not featured in the respective NOA Report.

23 This review process will also involve discussions with the TO to review the technical need and options development process adopted. In addition, to ensure that a credible range of options are included in the Needs Case, the SO may develop any non TO led options at this stage (e.g. non-build options, offshore integration options). Depending on the nature of the project, the TO may request the SO to undertake some additional technical analysis. The type and extent of this analysis will be agreed on a project by project basis.

24 **Step 9: Cost Benefit Analysis (CBA)**. SO requests the TO to provide a range of information to perform the CBA. The SO performs a CBA on the agreed options. (Full details on CBA methodology are presented in Appendix C, while an overview of the CBA process is presented in the Appendix B). Upon completion of the analysis, the SO will provide the TO with an independent CBA report, which will include a recommendation for the least-worst regret preferred option for the project.

25 Along with the report, the SO will also provide a copy of the CBA model to both the TO and Ofgem, including all results of constraint cost simulations for scenarios and options appraised. Depending on the type of model used[7] to forecast the constraint costs, the SO may also be able to provide the model used for constraint simulations (on a confidential basis).

26 **Step 10: TO prepares and submits the SWW Needs Case to Ofgem**. The results obtained from the CBA, are incorporated into the Needs Case submission. The TO

[7] The SO currently uses an in-house developed open source model for constraint cost forecasts. The SO is able to share this model, along with all input assumptions, with the TOs. This model will be replaced in the future by a third-party package. The SO will not be able to share this model with the TOs or Ofgem. However, the SO will be able to share all input assumptions adopted for the simulations performed in this model.

may wish to present additional evidence in relation to the CBA, as necessary. The SO provides additional support as required by the TO.

27 **Step 11: Ofgem's assessment of the Needs Case**. During the Ofgem assessment the SO and TO will jointly respond to any queries from Ofgem. Based on the Ofgem feedback, reconsideration of particular elements of the Needs Case may be required. The SO will provide support to the TO as necessary at this stage (particularly in terms of the choice of scenarios, review of the options and the CBA). Upon receiving all clarifications from the TO and the SO, Ofgem may seek to consult stakeholders regarding the Needs Case. The SO will continue to provide comments through such consultation process.

28 **Step 12: Ofgem's decision on the Needs Case**. Ofgem make a decision on the Needs Case and progress the project to the next stage, as appropriate.

29 **Step 13: The TO prepares SWW Project Assessment**. The SO is unlikely to be able to provide much support at this stage. However, if the costs for the preferred option have changed considerably or there are notable changes in the scenarios, the SO may need to refresh the CBA analysis.

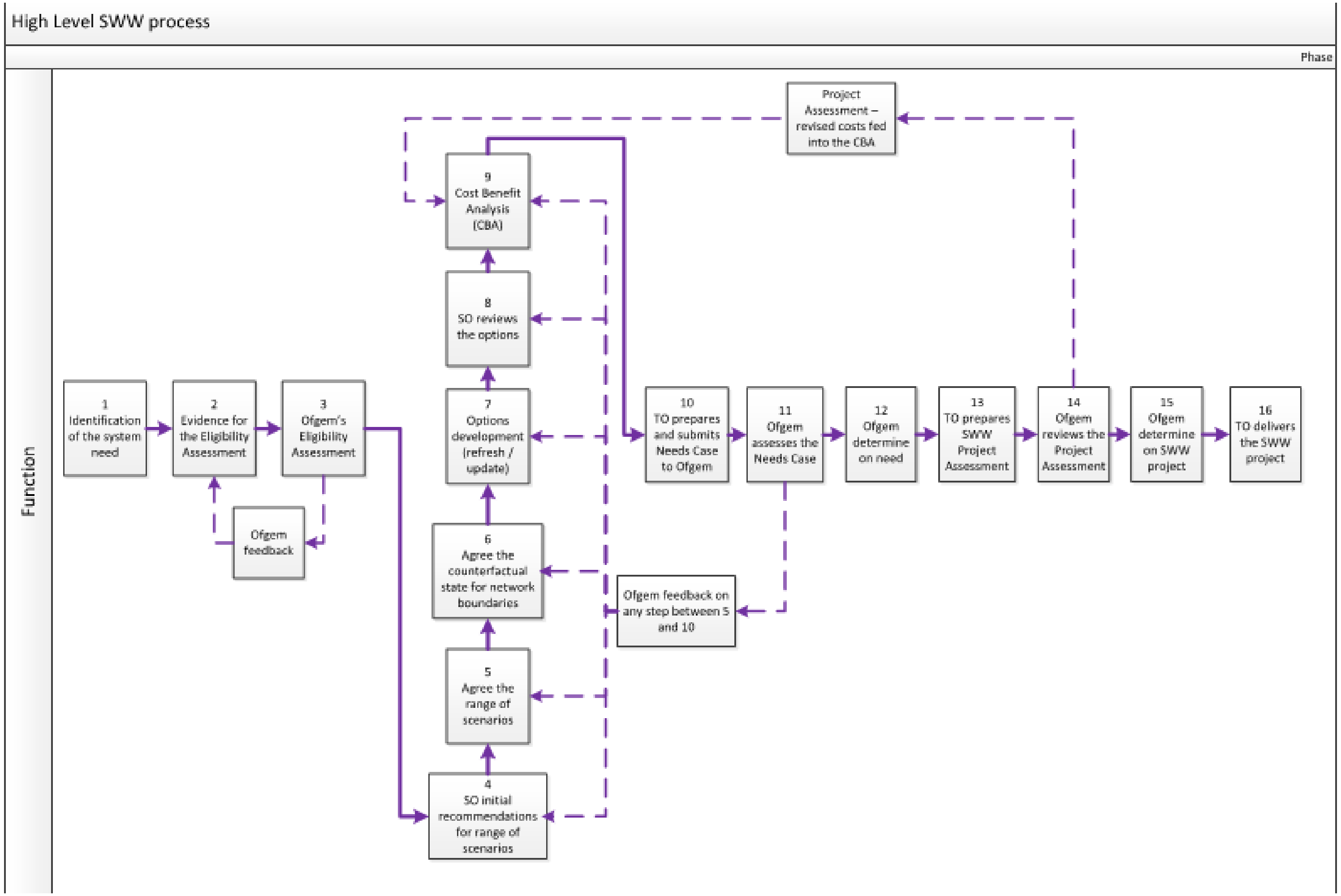
30 **Step 14: Ofgem's review of Project Assessment**. Ofgem will assess the Project Assessment, and the SO and the TO will respond to any queries, as necessary. Ofgem will consult the stakeholders as part of this review. The SO will continue to provide responses through the consultation process. Equally, the SO will provide any further evidence as necessary to support the TO. This may include further analysis on operability and optimal timing.

31 **Step 15: Ofgem determines on the SWW project**, including efficient costs and SWW outputs, and instigates a licence change, as necessary.

32 **Step 16: The TO delivers SWW project**.

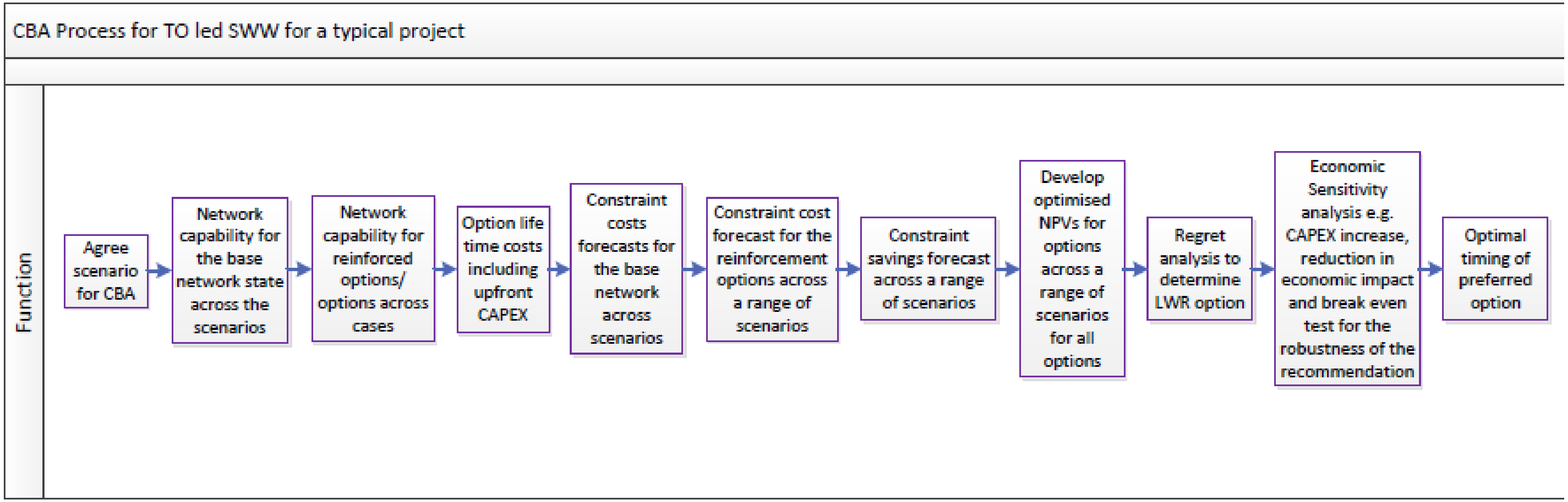
33 The SWW process flow diagram is presented in the Appendix A. The CBA process is presented in Appendix B, while full details of the CBA process are presented in Appendix C.

Appendix A: Strategic Wider Works (SWW) Process Flow Diagram



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

Appendix B: Cost Benefit Analysis Flow Diagram



This diagram shows the overall Cost Benefit Analysis process performed for a typical new project seeking approval from Ofgem through SWW submission. Detail of the Cost Benefit Analysis methodology is explained in the Appendix C.

Appendix C: Cost Benefit Analysis for TO led Needs Cases

Introduction and Context

C1 On-going changes to industry frameworks such as Integrated Transmission Planning and Regulation (ITPR) and NOA coupled with the forthcoming enhanced SO role of National Grid, place greater emphasis on integrated GB network investment planning and optimisation. These industry changes will raise stakeholder expectations on National Grid activities, and demand high quality Cost Benefit Assessments to support Needs Case documents for network developments.

C2 The Economics Team within Electricity Network Development has been established to appraise the value associated with specific network developments. These developments tend to either follow the prescribed Strategic Wider Works (SWW) process, or stem from a connection application for a new generator / interconnector connecting to the GB electricity system.

C3 National Grid's ETYS process performs a related annual network assessment to help plan future developments on major network boundaries, but does not consider discrete project developments separately or map them across all Future Energy Scenarios (FES) generation backgrounds. The Economics Team provides a detailed appraisal of specific projects to determine the economic merit of different solutions based on prevailing FES backgrounds and pertinent local factors, whilst respecting requirements of the Security and Quality of Supply Standards (SQSS) and the expectations of our NETS stakeholders.

C4 Each network development proposal is managed as a new project entity in which a range of solutions are studied and contrasted. The comparison accounts for forecast lifetime investment costs, lifetime operational savings and the corresponding network value that each solution offers. Assessments are conducted on a GB-wide basis since all projects within the GB market place have implications for the wider GB customer base in terms of capital and operational expenditure (Capex and Opex).

CBA Objectives

C5 The CBA objective is to produce and contrast key economic measures for various network solutions from a GB-wide customer perspective, leading to solution preference based on strict economic criteria. Solution preference is considered across a range of scenarios and accounts for all pertinent cost streams and factors. The CBA relies upon of a series of detailed and structured projections including: -

- FES backgrounds (generation and demand)
- Any local generation (or other) sensitivity with significant influence
- The future network state based on ETYS
- The boundary capability changes associated with each solution (and background)
- Forecast Capital Expenditure by solution (P50, P80[8] values)

[8] Probability (P) is the chance of an investment cost being exceeded. P50 refers to 50% chance and is therefore the mean expectation, whilst P80 implies a 20% chance of being exceeded.

- Any significant asset refurbishment cost and its timing
- The life span of the assets
- Future cost of capital (Weighted Average Cost of Capital or WACC) by investor share
- Social Time Preference Rate (STPR) of 3.5% pa[9].
- Future fuel prices and carbon prices
- Future renewable subsidy projections
- The operating regime of interconnectors

C6 At a high level, these forecasts serve to simulate future market conditions and identify how balancing actions will be utilised by the System Operator (SO). More discussion on how these assumptions contribute to the analysis can be found in Appendix 1 in the form of an illustrative CBA example.

CBA Preference Selection Philosophy

C7 The CBA analysis delivers a series of economic performance matrices reporting the Net Present Value (NPV) and corresponding Regret metrics for each potential solution, under each background. Whilst both the NPVs and Regret measures are reviewed, any emerging solution preference or recommendation is based on a Least Worst Regret (LWR) approach, provided solution stability and robustness can be demonstrated.

C8 Least Worst Regret analysis is designed to identify solutions from the range of possibilities which are least likely to be wrong across the range of uncertainties. It is not designed to pick options that offer the largest benefit (highest NPV), although this often occurs coincidentally. This approach provides a more stable and robust decision against the range of uncertainties, and minimises the chance of a particularly adverse outcome impacting consumers.

C9 The underlying economic philosophy is that it is advantageous to pick the solution that has the lowest adverse consequence across the range of studies, given the uncertainties in forecasts and other assumptions. It requires that all studies are seen as credible at the investment decision stage. Importantly, they need not be equally likely, and are unlikely to be so given the nature of uncertainty within future market place and wider industry.

C10 A regret measure is defined as the difference in the NPV between 'the option being considered' and 'the best possible option under that scenario', i.e. for each scenario, all options are considered against the option that offers the maximum NPV (taking into account both investment and operational costs). It follows that the best alternative has zero regret against which all other options in the scenario are compared. The mechanics of this can be seen in the Appendix D, which presents a worked example.

[9] Although the HM Treasury's Green Book recommends reducing the STPR after first 30 years of the appraisals, the SO proposes to adopt the 3.5% p.a. STPR (discount rate) over the entire appraisal period. This is not least because the Treasury's recommended reduction is unlikely to make any material change to the outcome of the analysis.

Best Practice in CBA

C11 There are usually a plethora of potential solutions to any specific network requirement. In order to focus CBA effort on a summary selection, a multi-criteria 'optioneering' process is required to filter the number of solutions down to a manageable number. Care must be taken to ensure that the set of solutions progressing to CBA retains the wider range and scope. This is because Best Practice in CBA work requires that a sufficiently wide and diverse set of options is progressed to adequately map the full solution space with reasonable resolution. Factors that should be evident in the range of solutions considered include: -

- The most minimal SQSS compliant solution (lowest possible investment cost solution meeting SQSS requirements)
- A range of topographical configurations where credible alternatives exist.
- A range of technologies (where practical)
- A range of capabilities (differing levels of boundary capability)
- A range of investment costs levels

CBA Methodology for TO led Needs Cases

C12 As identified in the core Network Options Assessment Report Methodology document, the NOA will provide investment signals for potential projects seeking to tackle congestion on the GB network. If the investment signal triggers the TO's Needs Case, the SO will assist the TO in undertaking a more detailed CBA. This Appendix provides an overview of the methodology which the SO will adopt for undertaking a detailed CBA as part of the TO's SWW Needs Case submission.

C13 Depending on the nature of the project, the SO may also provide further support on developing and reviewing the technical need of the project. The processes regarding such support are currently being will being developed and will shared with the TOs, Ofgem and the wider industry at a later date.

C14 Driven by the objectives of the CBA and the context outlined above, the overview of the methodology is summarised below:

- Establish the reference case position in terms of constraint costs forecasts associated with the counterfactual network state, across a range of generation scenarios and sensitivities. In order to undertake this assessment, the TO will need to analyse and provide data on counterfactual network capabilities for the boundaries affected for all agreed scenarios and sensitivities.
- Model constraint forecasts for the deliverable options short-listed by the TO across a range of generation scenarios and sensitivities. Again, in order to undertake this assessment, the TO will need to analyse and provide data on network capabilities by boundaries affected for all agreed scenarios and sensitivities for each short-listed investment option.
- Establish the forecasts of economic impact, measured as constraint cost savings, of the short-listed options, across the studied generation scenarios and sensitivities, over the options' assumed asset life.

- Undertake Cost Benefit Assessment, by:
  - Appraising the economic case of the options by adopting the Spackman[10] approach and determining respective NPVs across the studied generation scenarios and generation sensitivities. In order to undertake this analysis, the TO will need to provide life time costs information for all short-listed options, including capital, maintenance and / or refurbishment costs (with annual expenditure profiles) as well as evidence on losses.
  - Establish life-time worst regrets associated with each option appraised
- Make recommendations for the preferred option i.e. the least-worst regret solution, taking into consideration the impact of sensitivities and breakeven analysis.
- Determine optimal timing of the preferred solution by assessing regrets across each scenario and sensitivity and different years of delivery.
- Assess the robustness of the recommendation by assessing the impact of key economic sensitivities e.g. increase in capital expenditure, reduction in forecast of economic impacts, performing breakeven analysis to establish the level of change required in forecast of economic impacts or capital expenditure to result in zero net present value of options across all scenarios and sensitivities.

C15 This process is summarised in the figure presented in Appendix B.

C16 The remainder of this document presents details of various critical elements pertinent to the CBA.

Study Backgrounds

C17 All prospective CBA solutions must be considered against all credible backgrounds such that their performance against each is mapped and understood. This means that all FES backgrounds are studied against all solutions, and any other specific dependencies based on local conditions are also explored across the same range. This provides a matrix of NPV outcomes allowing comparison by solution and by background.

C18 The SO will work together with the relevant TOs to develop and agree a suitable range of credible scenarios for the CBA.

[10] 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.

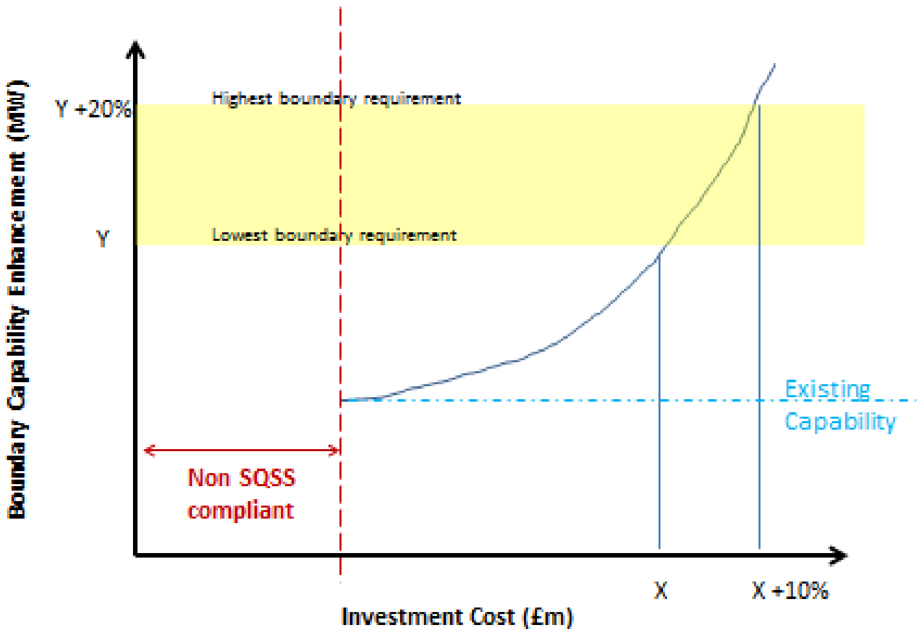
Forecasts and Projections

C19 Future forecasts within the CBA process follow one of two opposing value streams, namely, constraint savings (a consumer benefit) and investment costs (a consumer dis-benefit). These two streams must cover the same time period, but come from different sources. The constraint cost savings are determined by a modelling process called ELSI. The investment forecasts are produced by Transmission Owner (TO) costing teams or National Grid's E-Hub team. Their yearly projections are developed into present value (PV) equivalents using agreed cost of capital and discounting methods within the CBA.

C20 Constraint cost savings are derived by comparing ELSI's annual constraint costs for a particular solution with the corresponding base/counterfactual condition. Where reinforcement improves network efficiency, a constraint saving will occur. Future constraint savings have the same discount rate (STPR, see below) applied to future year values to account for the time-value of money. This provides a PV of constraint cost savings for each solution, for each background.

C21 All future investment costs must account for the investors Weighted Average Cost of Capital (WACC) and future payments discounted (by STPR) to produce a PV of the anticipated investment expenditure. These calculations follow the recognised 'Spackman' accountancy methodology designed to account for the time-value of money.

C22 In some circumstances, such as where the base reference point is the least cost SQSS compliant solution, the corresponding investment cost should be derived from the incremental cost of the solution (the additional expenditure relative to the reference solution). In this way, a presumption that as an absolute minimum the least cost SQSS compliant solution already exists, but that enhanced consumer value in additional incremental reinforcement may be achieved. In simple terms this could be likened to exploring economies of scale as illustrated below:



Constraint Cost Savings forecasting

C23 National Grid's preferred in-house modelling tool for medium to long range network constraint cost forecasts is called 'ELSI'. This tool is capable of producing medium / long term forecasts of network constraint costs for different network states and for various FES backgrounds. FES forecasts provide suitable data for modelling a 20 year period which may, occasionally, be sufficient to reflect the life expectancy of an asset. More typically, asset life is expected to exceed a 20 year period, hence an extrapolation technique is used to populate latter years. Typically, the final (20th) year values are adopted for each and every additional year to match the asset life horizon; although other alternatives may be considered if final year results appear particularly volatile. Most generation and transmission assets are assumed to have a 40 year life span, hence constraint cost savings must span this duration too.

Investment Cost Projections

C24 Each possible design solution is examined and costs are estimated by a specialist team. National Grid's dedicated National Grid team is E-Hub, other TOs have their own teams. Their investment cost projections should detail the total cost (including P50 and P80 contingency provisions), the spread of costs across development years and any significant refurbishment cost anticipated during the assets' life. The yearly investments are mortgaged over the asset life using the WACC assumption, and corresponding future payments discounted by STPR to derive Present Values (PVs) of each solution.

C25 Generally, P50 investment cost values are used in the CBA, however, the analysis is repeated with P80 values providing insight into the way in which delivery risk can influence preferences. This ensures that if a cheap but more risky solution emerges as a preference based on the P50 (ie. mean) values, then the P80 study will reveal this exposure.

Counterfactual / Base References

C26 The Counterfactual or Base network condition is the reference point to which other solutions are compared to identify the scale of benefit offered by the solution.

C27 There are several approaches to establishing a suitable counterfactual reference. Where practical, the base or counterfactual condition is either the 'do nothing' or 'do minimum' condition.

- The 'do nothing' is based on the existing network state without the introduction of this particular project. The 'do nothing' condition lends itself to conditions where the prevailing network state is SQSS compliant but significant network congestion is likely.

- The 'do minimum' refers to that level of investment required for this project in order to meet SQSS requirements. This is helpful where new connection assets are required to meet SQSS.

C28 Occasionally, it may be impractical to derive a counterfactual state. This could be because several low cost compliant solutions co-exist or where SQSS requirements are open to interpretation. Under these circumstances it is reasonable to regard the 'best solution within each background' as the reference point from which others solutions in the same background are measured.

C29 If, due to the bespoke nature of the project appraised, the definition of the counterfactual cannot be defined as the 'do nothing' and requires further considerations, the SO and the TO will engage with Ofgem with appropriate evidence for feedback on this issue, early in the assessment process.

NPVs and Regret Metrics

C30 The economic measures of NPV and corresponding regret matrices are developed to allow cross comparison of the solutions across scenarios and backgrounds. NPVs are generally the difference between PV investment costs and PV of constraint savings. Where constraint savings exceed investment costs then the solution has economic merit relative to the counterfactual state. Where NPVs are negative, then the converse is true.

C31 If the solution delivery timeframes are flexible i.e. not driven by a fixed contracted date, then solution NPVs may flex across different years. This occurs where the constraint savings in early years are lower than the corresponding finance costs or the converse. To explore optimal timing, the NPVs for each study are calculated across the first 10 years from the EISD (Earliest In Service Date) and the largest NPV (and corresponding year) is then determined. This ensures optimal timing for each solution by background is captured in the CBA for the purposes of cross comparison.

C32 Where several solutions show economic merit (positive NPV) then comparison can be made through Regrets analysis. Regret is defined as the difference between the NPV for a particular solution and the best solution across all backgrounds. Preference is then given to solutions that offer the lowest level of regret across all backgrounds and is called the Least Worst Regret (LWR). This LWR mechanism is demonstrated in the Appendix D.

Optimal Timing across all Backgrounds

C33 If divergence of the project's optimal timing (highest NPVs by year) occurs across different backgrounds (as is often the case), a second regret table is developed for any preferred solution(s). This reports the competing pressures across all backgrounds for a specific solution and helps identify the minimum timing regret across early years. This is illustrated in the Appendix.

Results

C34 The CBA methodology is designed to identify a preferred solution that maximises value, minimises risk and identifies optimal timing. Generally, the LWR solution offers the most economic course of action. However, this should be reviewed to establish that the solution is genuinely independent of the others and that it demonstrates a satisfactory level of robustness against unforeseen exogenous variables. This is tested through generic robustness tests in which either: -

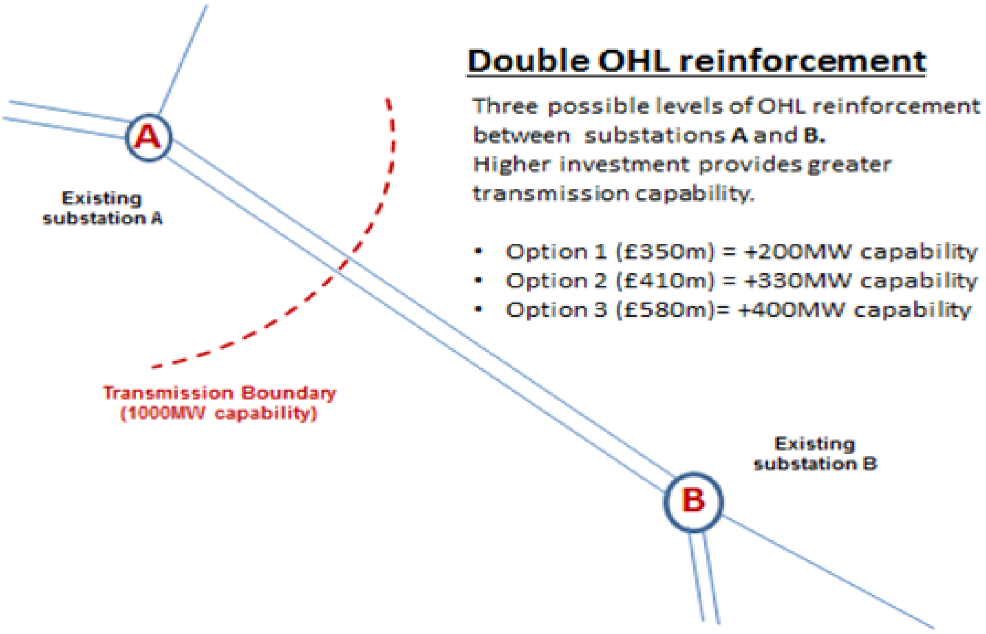
- Constraint cost savings are reduced by fixed percentages without impacting the outcome,
- Investment costs are increased by fixed percentages without impacting the outcome.

C35 Furthermore, the scale of the regrets that drives the LWR selection should be considered in relation to the scale of the investment cost. If a disproportionate increase in capital cost yields only a marginal improvement in regret values (which drives the LWR), then a simple review should also be undertaken. Where investment costs are in the billions and the regrets measures are in the few millions, then preference should be given to cheaper solutions since investment costs are less likely to undershoot than constraint savings overshoot. Investment costs are certainly more tangible and stable than constraint savings across the asset lifetime.

Appendix D: An Illustrative new connection / reinforcement CBA example

D1 Consider an example case where a length of transmission circuit is regularly the critical pinch point resulting in network constraint actions, and that this condition is forecast to increase in future.

D2 The multi criteria optioneering filter has already ruled out any new circuit route as there are much cheaper reconductoring options available which do not present significant planning delays. The counterfactual state is the existing network state with a 1000MW capability without any upgrades. This represents the reference condition from which other solutions are measured. There are four counterfactual models, one for each FES background scenario.



D3 In this example, we have a transmission boundary that requires reinforcement due to changing generation background patterns. The existing network has a 1000MW capability and there are three possible reconductoring options that could be implemented. The options would provide various levels of enhancement and investment cost, as illustrated in the table below.

Option	Capability Enhancement (MW)	Resulting Capability (MW)	*Investment Cost (£m)*
Option 1	200	1200	***350***
Option 2	330	1330	***410***
Option 3	400	1400	***580***

D4 Investment Costs range from £350m to £580, and as investment costs increase, transmission capability increases, but the relationship is not linear, and typically has step increases due to the standard unit sizes of transmission assets.

D5 Each of the three reinforcement solutions represents an increasingly expensive network investment with enhanced boundary capabilities compared to the existing state. The CBA will be able to identify the economic trade-off between investment costs and lifetime constraint savings. All of the options can be delivered within the current year hence no future year discounting is required, and the PV of investment cost is as shown in the table above.

D6 ELSI models are constructed to reflect the corresponding boundary capabilities, and run to determine the yearly constraint costs for each solution against each background. Results are consolidated into Present Values using the STPR assumption discussed previously.

D7 These constraint values are deducted from corresponding counterfactual case values to isolate the savings associated with the solution for each year. These forecasts are repeated across all backgrounds including any relevant local scenario designed to explore the wider solution space.

D8 The PV of constraint savings for each solution, by background is produced and is shown in blue below. The corresponding NPVs are produced by deducting the investment PV from the savings PV. This is shown in the second table below where GG – Gone Green, LCL – Low Carbon Life, SP – Slow Progression and NP – No Progression.

PV of Constraint Savings (£m)	FES Scenario				PV of Investment Cost (£m)
Option	GG	LCL	SP	NP	
Option 1	*£423m*	*£413m*	*£378m*	*£324m*	***£350m***
Option 2	*£800m*	*£720m*	*£600m*	*£430m*	***£410m***
Option 3	*£979m*	*£800m*	*£630m*	*£460m*	***£580m***

NPVs by Solution, by FES Scenario	FES Scenario			
	GG	LCL	SP	NP
Option	NPV	NPV	NPV	NPV
Option 1	*£73m*	*£63m*	*£28m*	*-£26m*
Option 2	*£390m*	*£310m*	*£190m*	*£20m*
Option 3	*£399m*	*£220m*	*£50m*	*-£120m*
column NPV max	£399m	£310m	£190m	£20m

D9 The NPV values shown are the maximum (or optimised) values achieved across credible delivery timeframes. The highest value for each background is identified and use as a reference to calculate the regret associated with other solutions. The completed regrets table is shown below.

Regrets £m					
Options	**GG**	**LCL**	**SP**	**NP**	**Worst Regret**
Option 1	*326*	*247*	*162*	*46*	***£326m***
Option 2	*9*	*0*	*0*	*0*	***£9m***
Option 3	*0*	*90*	*140*	*140*	***£140m***
		Least Worst Regret: Option 2			***£9m***

D10 The Worst Regret for each solution (across the rows) is logged, and then the Least Worst Regret identified. In this example the LWR is Option 2 with £9m regret and is the best option across three of the backgrounds. This solution has a £410m investment cost.

D11 If repeating this assessment for credible reductions in constraint savings or increases in investment costs gives the same patterns, then we can conclude that we have found a stable preference that offers protection from adverse outcomes and the best investment value for money.

Optimising Delivery Timescales

D12 Having determined a robust LWR solution, consideration of its delivery date is required. This entails repeating the Regret analysis but with a fixed solution (the LWR) and flexing the delivery year. This means that the NPV values are mapped across each delivery year and compared against the best, by background. This gives a timing regret table as shown below.

LWR Solution	
Commissioning Year	Timing Regret (£m)
Year 1	100
Year 2	69
Year 3	48
Year 4	47
Year 5	97
Year 6	160
Year 7	225

D13 Plotting this relationship reveals the opposing risks of early investment versus late investment. It can be seen that: -

- Commissioning to meet year 4 is the optimal time frame, although year 3 is almost the same.
- The exposure for late delivery exceeds that of early delivery