Network Options Assessment Report Methodology

Electricity System Operator
Transmission Network Service

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nationalgrid

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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 2015/16. It covers the methodology on which NGET in its role as SO will base the initial NOA report which will be published by 31 March 2016. As the methodology evolves due to experience and stakeholder feedback, the methodology statement will be revised for the second NOA and on an enduring basis as required by Licence Condition C27.

Network Options Assessment Methodology

Contents

Network Options Assessment Methodology 2
Introduction 4
Overview 4
Differences between NOA and ETYS 4
Appendix A: Network Options Assessment Methodology 5
Introduction 5
Collect Input 7
Updated Future Energy Scenarios 7
Sensitivities 9
Interconnectors 9
Latest version of National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) 10
Identify future transmission capability requirements 10
National generation and demand scenarios 10
Identify future transmission solutions 11
Build GB Model 13
Boundary capability assessment for options 13
Cost Benefit Analysis (CBA) 15
Introduction 15
CBA Methodology 16
Electricity Scenario Illustrator (ELSI) 18
Selection of preferred option 18
Single Year Least Regret Decision Making 18
Process Output 21
Report drafting 21
Report publication 22
Stakeholder consultation 23
Methodology 23
Report output 23

Area for further development ... 24
Provision of Information ... 24
Appendix B: System Requirements Form Template ... 25
Appendix C: NOA Study Matrix ... 29
Appendix D: NOA Process Flow Diagram ... 30
Appendix E: Summary of Stakeholder feedback ... 35

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).

3 This methodology document describes the end to end process for the analysis and publication of the initial NOA report (to be published by 31 March 2016) and clearly identifies the roles and responsibilities of the SO and TOs.

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

5 Appendix A describes the process and the headers used follow the flow diagram in Appendix D for clarity. Appendices B and C contain supporting information.

6 In accordance with Standard Licence Condition C27, the SO has sought the input of stakeholders. Appendix E summarises any views that the SO has not accommodated in producing this NOA report methodology.

Differences between NOA and ETYS

7 The NOA process is an obligation under NGET Licence, Standard Licence Condition C27 (The Network Options Assessment process and reporting requirements). Specifically, paragraph 14 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.

8 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.

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

Appendix A: Network Options Assessment Methodology

Introduction

A1 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.

A2 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. The SO has engaged with the onshore TOs to develop this initial methodology statement. The Offshore TOs declined to be involved in formulating the initial NOA methodology but the SO will continue to offer the opportunity for consultation. Following publication of the NOA report further stakeholder engagement is undertaken to inform the methodology statement for supporting further NOA reports.

A3 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.

A4 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.

A5 NGET Licence Condition C27 Paragraph 14 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 14(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 safely, economically and efficiently co-ordinate and direct the flow of electricity onto and over the national electricity transmission system in both the short and long term;
>
> (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;
>
> (c) have regard to interactions with existing agreements with parties in respect of developing the national electricity transmission system and changes in system requirements.

A6 References to 'weeks' in the NOA report methodology are to calendar weeks as defined in ISO 8601. This follows the system used the Grid Code OC2.

Major National Electricity Transmission System Reinforcements

A7 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 determined 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.*

A8 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 benefit.

Eligibility criteria for projects for inclusion / exclusion

A9 The NOA report presents projects that are expected to increase capacity on the national electricity transmission system as defined by Major National Electricity System Reinforcements (see definition above).

A10 The SO provides a summary justification for any projects that are excluded from detailed NOA analysis.

A11 Once a Needs Case has been approved by Ofgem, the option is excluded from the NOA analysis and report, as it is managed through the Strategic Wider Works (SWW) process.

Roles and responsibilities of SO and TOs

A12 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.

A13 The SO role and responsibilities are based around its overview of the network requirements. Specific role areas are:

- Analysis of UK Future Energy Scenarios (UK FES) data
- Technical analysis of boundary capabilities for England and Wales
- Running Cost Benefit Analysis (CBA) studies
- Production and publication of NOA report.

A14 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.

The headers in this methodology follow the stage names in the process diagram in Appendix D.

Collect Input

Updated Future Energy Scenarios

A15 The relevant set of UK Future Energy Scenarios (UK 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 2035 in detail and at a higher level to 2050. The UK FES document is consulted upon widely and published each year as part of a parallel process.

A16 The NOA process utilises the main UK 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 UK FES consultation process. In the event of any change, the rationale is described and presented within the UK FES consultation report that is published each year.

A17 In 2015, the four main scenarios are:

- Gone Green – The Gone Green scenario represents a potential generation and demand background which meets the environmental targets in 2020 and maintains progress towards the UK's 2050 carbon emissions reduction target. The achievement of the climate change targets requires the deployment of

[1] This is anticipated for the initial NOA report.

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 and so carbon reduction policies cannot be implemented as quickly as under that scenario. 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, because the economic conditions are less favourable than other scenarios and there is less of a political 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 more future economic 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 nuclear and gas generation at a national level. There is minimal deployment of new low carbon technologies, with the technology not achieving commercial scalability e.g. Carbon Capture and Storage (CCS), marine.

A18 The demand scenarios are created by using a mix of data sources, including feedback from the UK 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.

A19 Using regionally metered data, the “ACS adjusted scenario demands” are split proportionally around GB.

A20 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.

[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.

Sensitivities

A21 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. The SO leads on the sensitivities in conjunction with the TOs and any feedback from stakeholders sought through the FES consultation process. This allows regional variations in generation connections and anticipated demand levels that still meet the scenario objectives to be appropriately considered.

A22 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.

A23 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.

A24 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.

A25 The modelling of interconnector flows during winter peak condition is based on an economic simulation driven by forecast energy prices for GB and remote markets in Europe. However, the modelling of interconnector flows during summer demand condition is based on historical precedent. In future, the modelling of interconnector flows during summer demand condition will be based on economic simulation. Therefore, we continue to work closely with stakeholders in developing our models of interconnector flows.

A26 The SO extends sensitivities studies further to test import or security constraints. UK 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

A27 The SO undertakes analysis to assess the optimum level of interconnectors capacity. Interconnectors are recognised in the background for the NOA report. Network capacity and welfare benefit are the key drivers for determining the optimum level of interconnection for GB consumers. The SO anticipates the market will respond to this intelligence with potential projects aligned with the optimum level of interconnectors recommended by the SO. This output is expected as part of ETYS 2016 (produced in November 2016) or the NOA report 2016 (produced March 2017). Interconnectors will be excluded from the ETYS 2015 and from the NOA report to be published by 31 March 2016.

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

A28 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

A29 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.

A30 The Security criterion is intended to ensure that demand can be supplied securely, without reliance on intermittent generators or imports from interconnectors. 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.

A31 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.

A32 The NETS SQSS also includes a number of other areas which have to be considered to ensure the development of an economic and efficient transmission system. Beyond the criteria above, it is necessary to:

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

A33 The SO uses the UK FES scenarios and the criteria stated in the NETS SQSS to produce the future transmission capability requirements by using an in-house tool

[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.

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

A34 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).

A35 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.

A36 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 B of this document provides detailed information about the SRF template.

A37 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.

A38 The options that the TOs provide are listed and described in the NOA report along with ‘non-build’ options such as commercial or ‘minimal-build’ options that the SO develops. The non-build solutions might include liaison with distribution licencees. The SO produces the description of the ‘non-build’ option in conjunction with the relevant TOs. The description includes the boundary that the option relieves, categorising the option into ‘build’, ‘non-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.

A39 It is recognised that as solutions develop, their level of detail increases. Solutions at a very early development stage might lack detail.

A40 The NOA process includes a window during which the TOs respond to the SO with completed SRFs.

A41 By Week 46 the Scottish TOs return the completed SRF after they have performed the technical assessment of the credible reinforcement options for their respective areas. The England and Wales TO returns the SRF earlier in June for the SO to perform the boundary capability assessment. The Scottish TOs perform the boundary capability assessment before returning the SRF.

A42 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 43. 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.

A43 Potential transmission solutions are presented in Table A1.

Table A1: Potential transmission solutions

Category	Transmission solution	Nature of constraint			
		Thermal	Voltage	Stability	Fault Levels
Low cost-investment	Co-ordinated Quadrature Booster Schemes	✓	✓		
	Automatic switching schemes for alternative running arrangements	✓	✓	✓	✓
	Dynamic ratings	✓			
	Enhanced generator reactive range through reactive markets		✓	✓	
	Addition to existing assets of fast switching equipment for reactive compensation		✓	✓	
	Demand side services (contracted for certain boundary transfers and faults)	✓	✓		
Operational	Availability contract	✓	✓	✓	
	Intertrip	✓	✓	✓	
	Reactive demand reduction		✓		
	Generation advanced control systems	✓	✓	✓	
Investment	Hot-wiring overhead lines	✓			
	Overhead line reconductoring or cable replacement	✓			
	Reactive compensation (MSC, SVC, reactors)		✓	✓	
	Switchgear replacement	✓			✓
	New build (HVAC / HVDC)	✓	✓	✓	✓

A44 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. This allows the SO to assess the most beneficial solution for customers.

Environmental impacts and risks of options

A45 Using the SRF the TOs provide views on the environmental impact of the options that they have proposed. They include in their views the environmental impact on the practicality of implementing each option on an easily understood scoring system such as RAG status.

A46 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, perhaps including a RAG status.

Basis for the cost estimate provided for each option

A47 The forecast total cost for delivering the project is split to reflect the pre-construction and construction phases. The forecast cost is a central best view.

A48 By Week 36, the TOs and SO agree each year the cost basis to be used for NOA analysis and a central cost figure of the project is provided for each option.

A49 The TOs provide the individual elements of the investments that provide incremental capability.

A50 For consistency of assessment across all options, the TOs provide all relevant costs information in the current price base.

Build GB Model

A51 The TOs submit a yearly power system model to the SO. The SO then creates the GB models and publishes the model for studies. Additional 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

A52 By Week 46, the SO has completed boundary capability assessment studies for England and Wales while the Scottish TOs have completed these studies for the own areas.

A53 The boundary capability that is assessed is the lowest of the thermal, voltage and stability (where required) capability. Each of these capabilities are 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.

A54 The boundary capabilities are assessed using the Gone Green scenario for the winter peak demand condition. 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 Chapter 5.

A55 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 C of this document.

A56 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.

A57 The factors shown in Table A2 below are identified for each transmission solution to provide a basis on which to perform cost benefit analysis at the next stage.

Table A2: 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="6">Stage[4]</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 rowspan="4">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</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</td><td>Designing the preferred solution into greater levels of detail and preparing for the planning process.</td></tr>
<tr><td>Planning</td><td>Continuing with public consultation and adjusting the design as required all the way through the planning application process.</td></tr>
<tr><td colspan="2">Construction</td><td>Planning consent has been granted and the solution is under construction.</td></tr>
</table>

A58 In order to assess the lead-time risk described in Table A2, new overhead line solutions with significant consents and deliverability risks are considered with both 'best view' and 'worst case' lead-times to establish the least regret for each likely project lead-time.

[4] These project categorisations are consistent with definitions defined as part of the ENSG process and published by DECC.

A59 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.

A60 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.

A61 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.

A62 The Scottish TOs use their boundary capability results in the SRFs that they submit back to the SO.

A63 The SO leads on non-build options in cooperation with the TOs. The economic analysis tool needs a MW value for the boundary capability which this analysis of non-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 (CBA)

Introduction

A64 Cost Benefit Analysis (CBA) 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.

A65 The NOA provides investment signals based on the Single Year Regret Decision Making process. If the investment signal triggers the TO's Needs Case, the SO will assist the TO in undertaking a more detailed CBA.

A66 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 recommendations of which wider works reinforcement projects to proceed with 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.

A67 The methodology follows the **Guidance on the Strategic Wider Works arrangements in the electricity transmission price control, RIIO-T1** document published by Ofgem[5]. A needs case is submitted by the TO that is proposing the project to the regulator, the needs case includes a CBA 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.

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

CBA Methodology

A68 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 CBA 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 Electricity Ten Year Statement. 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).

A69 All of the UK 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.

A70 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 Electricity Scenario Illustrator (ELSI) (see the box on page 18 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[6] methodology.

A71 It is assumed that each transmission asset is to have a 40 year asset life, since ELSI 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 UK 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.

[6] 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.

A72 This CBA 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.

A73 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’.

A74 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.

A75 A reinforcement is critical if, in any scenario or sensitivity the optimum year for the reinforcement is such that if a delay decision were made then the optimum year could no longer be met (note that outage availability may play a part in this decision).

Electricity Scenario Illustrator (ELSI)

A76 The constraint modelling tool currently used by the SO is called ELSI; it is used to forecast the constraint costs for different network states and scenarios. It is an open source tool developed in house and made available for stakeholders to conduct their own constraint forecasting. The tool is an Excel based model. The high-level assumptions and inputs used in ELSI are outlined in table A3.

Table A3: Assumptions and input data for ELSI.

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	
Forecast system marginal prices for overseas markets	Baringa	20 year forecast, varies by scenario and market
Wind data	Poyry (historic)	Wind load factors for various zones around the UK
Demand data	FES	Annual peak and zonal distribution
Load duration curve	Historic data	2012/13 outturn data converted into ELSI periods
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

A77 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 ELSI for the CBA 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

A78 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.

Single Year Least Regret Decision Making

A79 The single year least regret methodology involves evaluating every permutation of the critical options in the first year and then assuming that information will be revealed such that the optimal steps for a given scenario can be taken from year two onwards. For each critical reinforcement the permutations are either to proceed with the project for the next year or to delay the project for the next year. If there is more than one critical reinforcement in the region then the permutations increase; the number of permutations is equal to 2^n, where n is the number of critical reinforcements.

A80 Each of the permutations have a series of cost implications, these are either additional capital 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.

A81 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 for each permutation and scenario is calculated as the difference between the present value of the current permutation for the current scenario and the present value that is lowest of all permutations for the current scenario. This results in one permutation having a zero regret cost for each scenario.

A82 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 A4. Note that the scenarios are colour-coded; this is used for clarity in following tables.

Table A4: Example of optimum years for two critical reinforcements.

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

Table A5: 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	

A83 Table A5 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.

A84 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 need then the investment will have been wasted.

A85 The regret costs for each permutation 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 investment recommendation output. In the example shown above the least regret permutation is to proceed with both reinforcements 1 and 2 which has a regret of £15m and is the least of the four permutations.

Process Output

A86 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 CBA. The SO reconciles the economy and security results (in accordance with NETS SQSS Chapter 4) before making a final recommendation on a preferred option.

Report drafting

A87 The SO drafts the NOA report but the responsibility for the contents 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 which shows responsibilities also.

Table A6: Overview of the NOA report contents

Report chapter	NOA report topic	Scotland	E&W	Comments
1	Aim of report	SO	SO	
2	Methodology description including definition of Major National Electricity Transmission System Reinforcements	SO	SO	SO consults with TOs
3	Project exclusions	TO	TO	TO makes the justification
4	Options	-	-	See table A7 below
5	Stakeholder engagement and feedback	SO	SO	

A88 The options are within a single chapter (4) and the component parts of the chapter and the responsibilities for producing the material are in the table below.

Table A7: Topics in the Options chapter in the NOA report

NOA report Options topic	Scotland	E&W	Non-build/ min-build	Offshore	Comments
The Options					
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: Environmental impacts and risks	TO	TO	TO	SO	
Options: Comparison of the options	SO	SO	SO	SO	
Table overview of boundaries and options	SO				

A89 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.

A90 Report drafting is undertaken in the period late November to mid-February.

Report publication

A91 The SO publishes the initial NOA report by 31 March 2016.

A92 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.

A93 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.

A94 The Licence Condition allows for the omission of sensitive information.

Stakeholder consultation

A95 The SO has consulted with the TOs and Ofgem whilst preparing this NOA report methodology.

A96 The key consultation areas are the NOA methodology, form of the NOA report and the NOA report outputs and contents.

A97 This section shows the timescales for the SO's consultation of stakeholders during the period of writing the NOA report.

Methodology

A98 The SO seeks stakeholder views annually for consideration and where appropriate implementation before the NOA process starts its annual cycle.

A99 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

A100 The SO makes available selected parts of the NOA report to key stakeholders 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.

A101 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.

A102 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.

Area for further development

A103 Licence Condition C27 Paragraph 6 (a) requires NGET to explain where it has not been possible for the NOA methodology to meet the information required by Paragraph 8 and how it will progress the outstanding issues. This section covers these matters.

A104 This NOA methodology is written for the NOA report which is to be published by 31 March 2016. The NOA methodology will be updated annually as the NOA process and report are modified following experience and stakeholder feedback.

A105 Expected areas for further development for the annual NOA report are:

- SO to conduct boundary capability studies for all of the national electricity transmission system
- Interconnector modelling (see below)
- Provision of Information to electricity transmission licensees and interconnector developers (C27 Part C)
- Review of NOA study matrix
- Consistent costing basis across all TOs and the SO
- Security assessment.

A106 The SO's interconnector evaluation output is limited for the initial NOA report. The optimum level of interconnectors recommended by the SO is expected as part of ETYS 2016 (produced in November 2016) or the NOA report 2016 (produced March 2017). Interconnectors will be excluded from the ETYS 2015 and from the NOA report to be produced in March 2016. Interconnectors are recognised in the background for the NOA report.

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

A107 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.

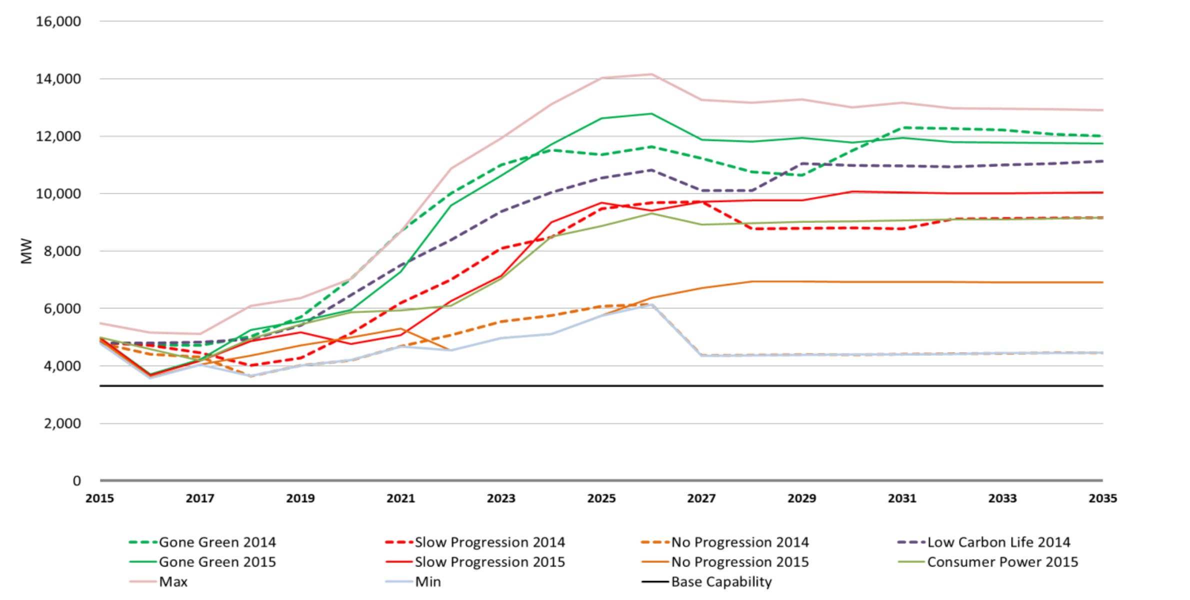
A108 In accordance with Licence Condition C27 Part C, the SO provides information to electricity transmission licensees, interconnector developers and to the Authority (Ofgem) if requested to do so. The SO will assist TOs with CBA for SWW Needs Cases.

Appendix B: System Requirements Form Template

Boundary B6

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

Boundary Required Transfer Summary:



Economy / Export		Secured event	2015/ 16	2016/ 17	2017/ 18	2018/ 19	2019/ 20	2020/ 21	2021/ 22	2022/ 23	2023/ 24	2024/ 25	2025/ 26
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 Chapter 5.

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

Security / Import		Secured event	2015/ 16	2016/ 17	2017/ 18	2018/ 19	2019/ 20	2020/ 21	2021/ 22	2022/ 23	2023/ 24	2024/ 25	2025/ 26
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 Chapter 4.

Boundary Power System Analysis Summary:

Reinforcement options:

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

Option 1:	Status: Same/Changed/New
Option Name: *Insert the name of the proposed reinforcement.*	
Description: *Provide a description of the physical nature of the reinforcement sufficient to allow power system modelling and costs to be developed.*	
NOA Description: *Description of the option suitable for public presentation*	
Diagram: *Put diagrams here of how the new configuration will look including circuits and substation layouts.*	
Boundary Capability Estimate: *Provide an estimate of the boundary capability (MW) offered by this reinforcement.*	
Solution: *Describe how the proposed solution is intended to increase capability and under what conditions.*	
Environmental impacts and risks: *Provide views on the environmental impact of the options*	
EISD: *Year*	Current Status: *Scoping, Delivery, etc…*
Cost Estimate: *£m for the option*	Scheme #: *All relevant or create a new reference if none already exist*

Red is required text.

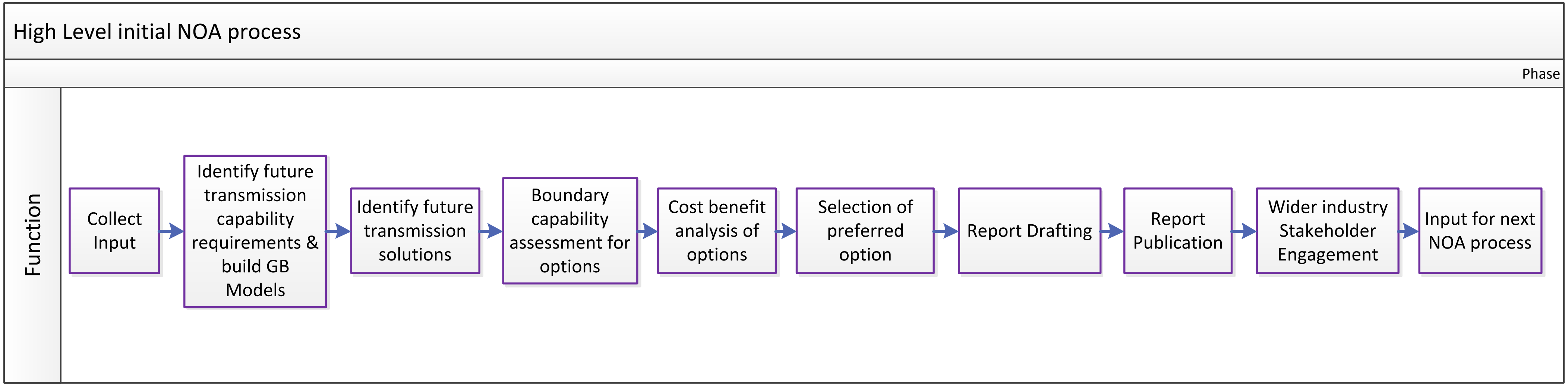
Option 1 costs profile (based on current year costs)

	2015 /16	2016 /17	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
Pre-construction																
Construction																
Total																

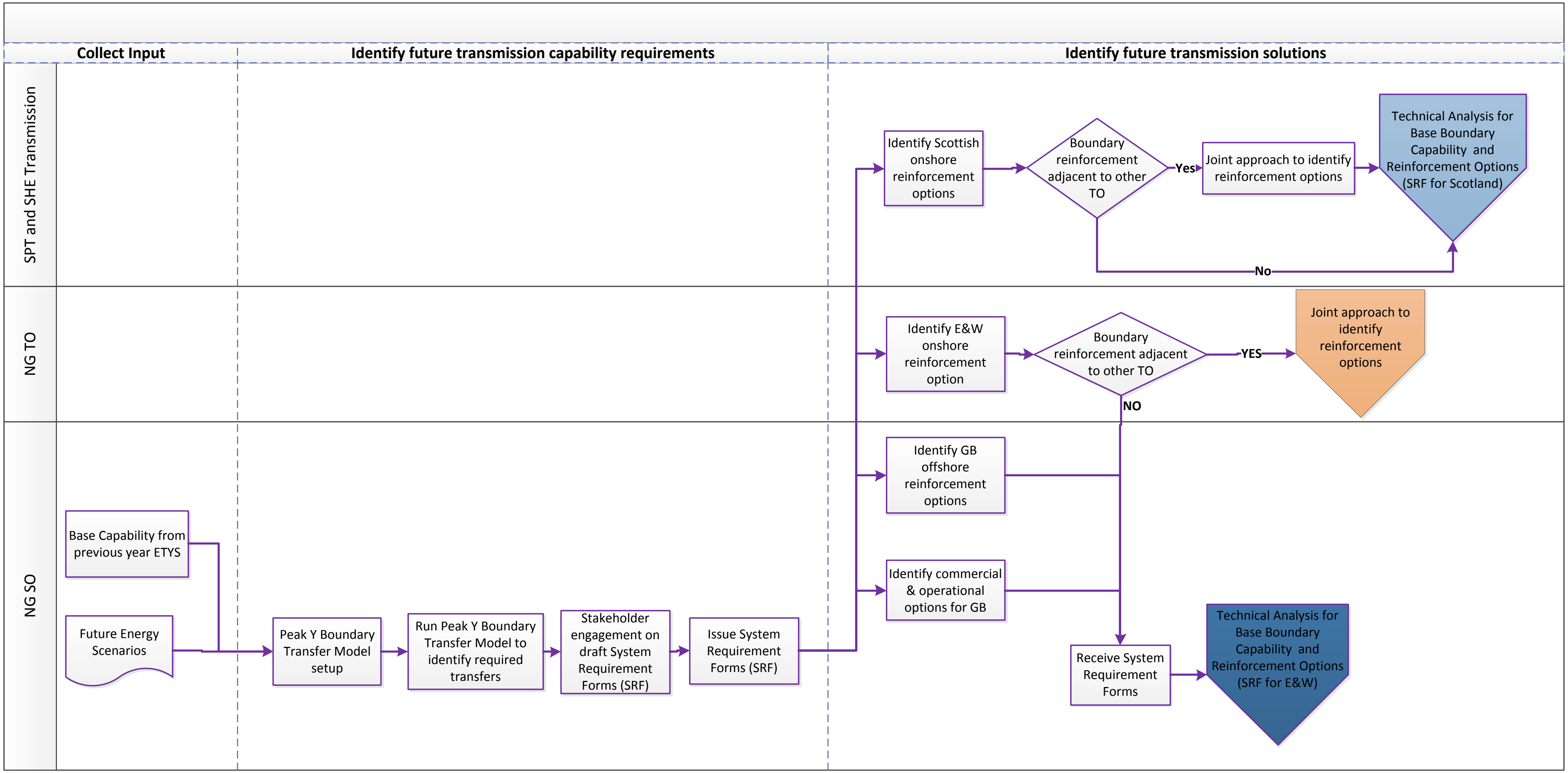
Appendix C: NOA Study Matrix

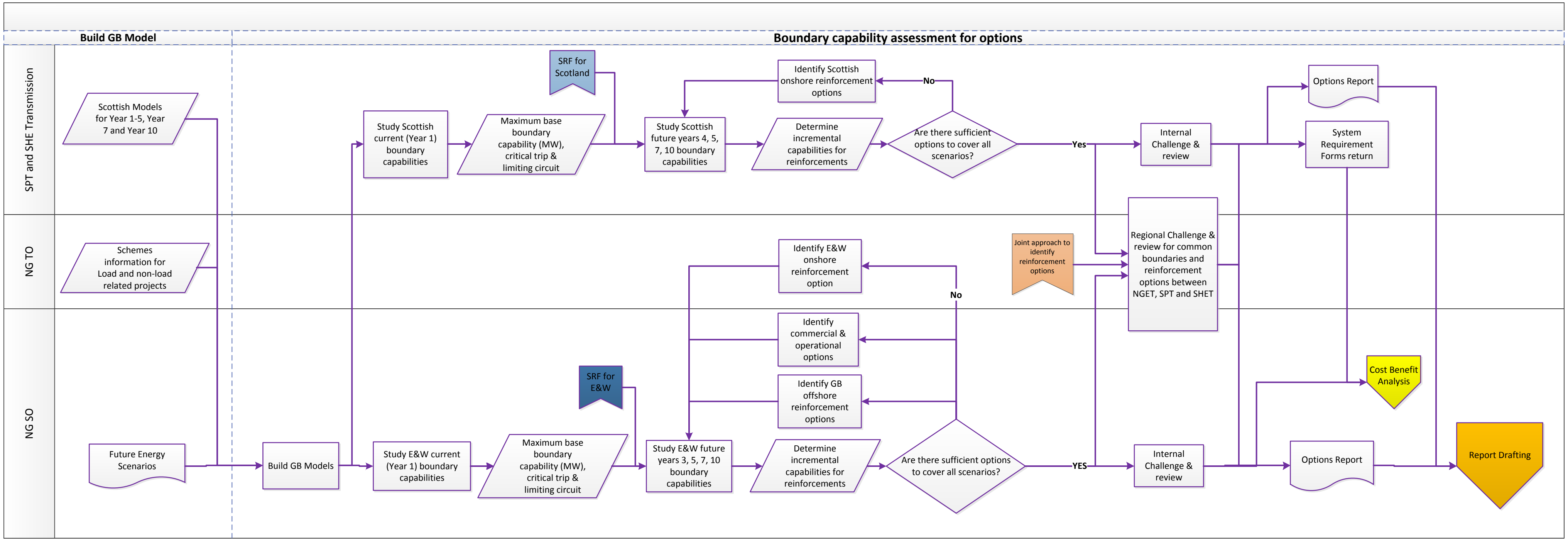
Assumption/Condition		Initial NOA (March 2016)	Comments
Generation Scenarios	Gone Green	✓	Technical and economic assessment of the reinforcement options; sensitivity studies where appropriate
	Slow Progression	✓	Economic assessment only of the reinforcement options; sensitivity studies where appropriate
	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
Demand	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	Transmission Based reinforcements	✓	
	Alternative non-build reinforcements	✓	Assessment of non-build reinforcement options
Study Years	Year 1		Year 1 analysis in NOA is not relevant due to the publication date in March 2016
	Year 2	✓	Assessment of non-build reinforcement options subject to availability
	Year 3	✓	Assessment of non-build reinforcement options subject to availability
	Year 4	✓	Assessment of build and non-build reinforcements options excluding those are subject to Ofgem agreement
	Year 5	✓	Assessment of build and non-build reinforcements options excluding those are subject to Ofgem agreement
	Year 7	✓	Assessment of build and non-build reinforcements options excluding those are subject to Ofgem agreement
	Year 10	✓	Assessment of build and non-build reinforcements options excluding those are subject to Ofgem agreement

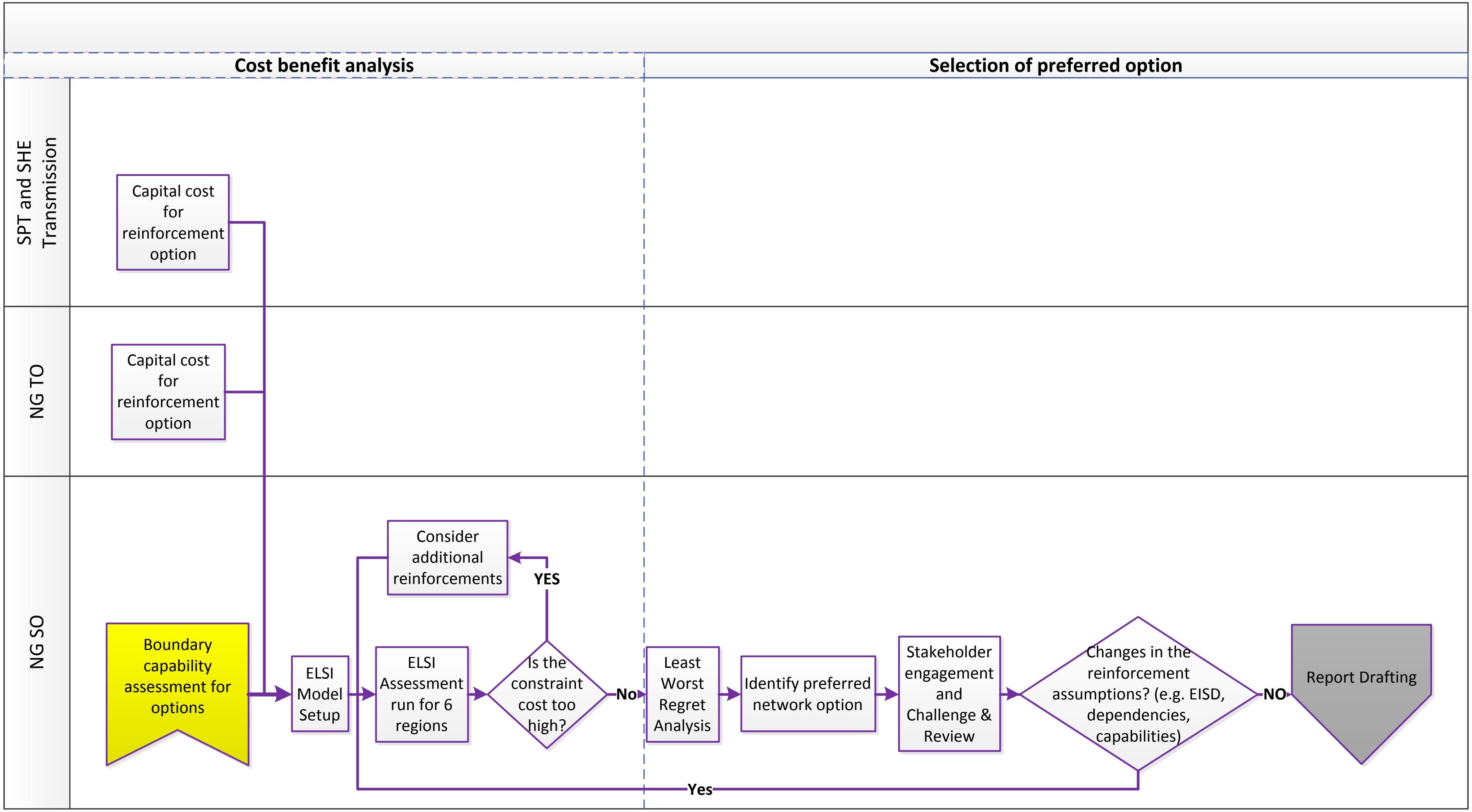
Appendix D: NOA Process Flow Diagram

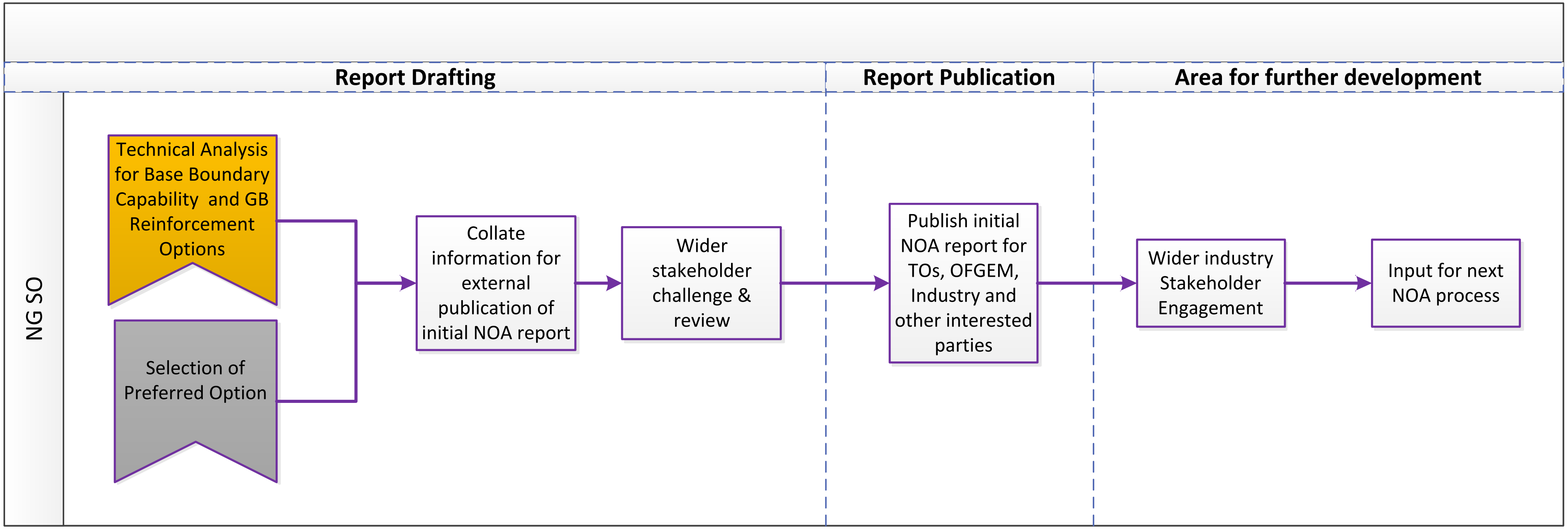


This diagram shows the overall NOA process. The text in each box corresponds to the descriptions of the stages at the top of the diagrams on the next pages. The process headings can also be found in Appendix A.


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
Base Capability from previous year ETYS
Identify commercial & operational options for GB
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
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 & limiting circuit
SRF for Scotland
Study Scottish future years 4, 5, 7, 10 boundary capabilities
Determine incremental capabilities for reinforcements
Identify Scottish onshore reinforcement options
No
Are there sufficient options to cover all scenarios?
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
No
Identify commercial & operational options
Identify GB offshore reinforcement options
Study E&W current (Year 1) boundary capabilities
Maximum base boundary capability (MW), critical trip & 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
ELSI Model Setup
ELSI Assessment run for 6 regions
Consider additional reinforcements
YES
Is the constraint cost too high?
No
Least Worst Regret Analysis
Identify preferred network option
Stakeholder engagement and Challenge & Review
Changes in the reinforcement assumptions? (e.g. EISD, dependencies, capabilities)
NO
Report Drafting
Yes


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 for external publication of initial NOA report
Wider stakeholder challenge & review
Publish initial NOA report for TOs, OFGEM, Industry and other interested parties
Wider industry Stakeholder Engagement
Input for next NOA process

Appendix E: Summary of Stakeholder feedback

Letter from SHE Transmission

Scottish and Southern Energy
Power Distribution

Inveralmond House
200 Dunkeld Road
Perth PH1 3AQ
email: jen.carter@sse.com

Julian Leslie
Electricity Network Development Manager
National Grid Electricity Transmission
Warwick Technology Park, Gallows Hills
Warwick
CV34 6DA

26 June 2015

Dear Julian,

Re: Development of the Network Options Assessment methodology

On behalf of Scottish Hydro Electric Transmission (SHE Transmission), I would like to express our appreciation for the opportunity to participate in the Network Options Assessment (NOA) working group and to contribute our views to the development of the proposed methodology.

Whilst we recognise the licence obligation sits with National Grid Electricity Transmission (NGET) as the System Operator (SO), we see the annual publication of a NOA report as a significant undertaking for all of the onshore Transmission Owners (TOs). As with similar documents like the Electricity Ten Year Statement and the National Electricity Transmission System Performance Report, we will support the SO in the collation of data relevant to our licensed area and associated analysis. To that end, we support the split of roles and responsibilities for the 2015/16 NOA report.

As per previous discussions, we remain concerned with proposals to bring forward the publication date in subsequent years, given the extent of data exchange that is required between parties.

We appreciate that further work is required to develop the methodology in relation to SO support to TOs during the development and assessment of Strategic Wider Works Needs Cases and look forward to discussion of this aspect over the summer.

Yours sincerely,

Jen Carter

Networks Regulation, Transmission

Letter from SP Transmission

SP ENERGY NETWORKS

Network Planning & Regulation

Julian Leslie
Electricity Network Development Manager
National Grid House,
Gallows Hill,
Warwick
CV34 6DA

Your ref

Our Ref

Date
30th June 2015

Contact / Extension
Alan Kelly/0141 614 1736

Dear Julian,

Re: Development of the Network Options Assessment methodology

On behalf of SP Transmission plc (SPT), I would like to acknowledge the effectiveness of the stakeholder engagement provided through the Network Options Assessment (NOA) working group. Our involvement with this group has allowed us to fully contribute to the development of the proposed process and methodology. This has been another good example of coordination and co-operation between the System Operator (SO) and all there onshore Transmission Owners (TO's).

Whilst we recognise the licence obligation sits with National Grid Electricity Transmission (NGET) as the SO, we recognise the annual publication of a NOA report will be a significant undertaking for all of the onshore TOs. To that end, we support the proposed timetable and delegation of roles and responsibilities for the 2015/16 NOA report.

As the working group has developed the scope of the methodology and report, we consider the ability for us to contribute effectively if the report is earlier than March in subsequent years will be a significant challenge. However, we are committed to providing the required data as best we can.

We look forward to continuing the engagement with you on the further development and delivery of the NOA process.

Kind regards

Alan Kelly
Transmission Commercial and Policy Manager
SP Energy Networks

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