Scottish & Southern Electricity Networks

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Cost Benefit Analysis Methodology

December 2019

Scottish Hydro Electric Transmission plc

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1 Section 1 – Context

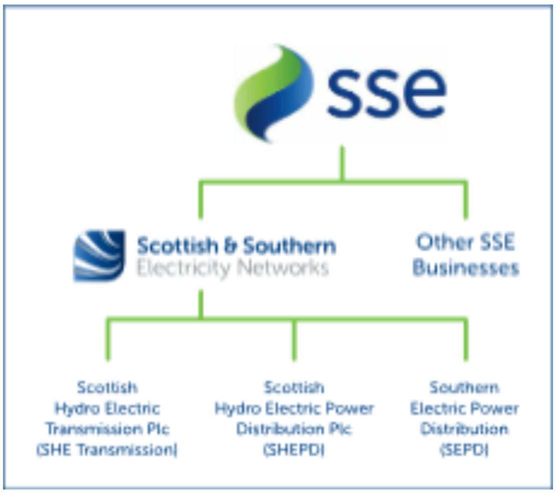
1.1 About us

Scottish Hydro Electric (SHE) Transmission is the owner of the high voltage electricity assets in the north of Scotland, as shown in Figure 1. As the Transmission Owner (TO) we own the 132kV, 275kV and 400kV electricity network in the north of Scotland. Our network consists of underground and subsea cables, overhead lines on wooden and composite poles and steel towers, and electricity substations, extending over a quarter of the UK's land mass and across some of its most challenging terrain.

Figure 1: North of Scotland Transmission Network

As part of Scottish and Southern Electricity Networks (SSEN), which includes our sister company Scottish Hydro Electric Power Distribution (SHEPD) the Distribution Network Owner (DNO) of the adjoining low voltage network, our electricity network is responsible for ensuring a safe, reliable supply of electricity to around 770,000 homes and businesses (Figure 2). We also provide grid access for over 7GW of generation, contributing to around one third of GB's renewable energy capacity.

Figure 2: SSE Group Structure



We power our communities by providing a safe and reliable supply of electricity. We do so by taking the electricity from generators and transporting it at high voltages, over long distances through our transmission network for distribution to homes and businesses in villages, towns and cities.

1.2 This publication

This document sets out the methodology we have applied to Cost Benefit Analysis (CBA) to support our RIIO-T2 Business Plan. The purpose of the methodology is to help decision makers within SHE Transmission make informed choices on investment decisions. It provides a framework for assessing the comparative societal, environmental and economic trade-offs associated with proposed investment options to enable the selection of the best value option for the end consumer. The approach outlined in this methodology can be applied to all investment types.

1.3 The need for Cost Benefit Analysis

As SHE Transmission is a provider of an essential public service in the North of Scotland, standard appraisal methods based on projected profits and investment expenditures are not applicable due to the intangible nature of public benefits associated with our investments. The application of Cost Benefit Analysis (CBA) helps us identify the most cost-effective allocation of public money that will enable us to continue to provide a reliable, effective transmission network and facilitate the transition towards a clean energy economy.

Before making any decision on expenditure, we must be certain that the investment is necessary, and the preferred option is the one that realises the most overall benefit for the GB energy consumer and local communities. This appraisal can be complicated by the long life and high cost of transmission infrastructure and in some cases, it can be of greatest benefit to build once rather than return to make a second upgrade. CBA improves the quality of such investment decisions by making explicit links between the inputs (i.e. the costs) and the outcomes (i.e. the benefits) of the investment. It attempts to express these in monetary terms which then enables the comparison across the alternative investment options.

It is worth noting that CBA is not an exact science and we use its outputs as a guide in our decision making, as opposed to trusting it delivers the definitive solution. CBA is one of many inputs that feed into the decision-making process, so results are typically used in conjunction with other analysis/qualitative considerations. There is always some need for assumptions or reliance on secondary data, which can limit the ability to draw out conclusive evidence for investment from the CBA alone. Therefore, we acknowledge that the outputs from CBA modelling should be used with care, with a full understanding of the limitations that may exist with the data and the assumptions upon which the analysis is based.

1.4 Ensuring consumer value

In May 2019, the Committee on Climate Change1 recommended a new emissions target for the UK: net zero greenhouse gases by 2050. In Scotland, the Committee recommended a net zero date of 2045, reflecting Scotland's greater relative capacity to remove emissions than the UK as a whole.

Striking the balance of consumer value and meeting net zero targets is no trivial task. Guidance provided in the Climate Change Committee's report, and by Ofgem indicates network operators should be developing 'future proof' network solutions i.e. where upgrades occur, they should be to a size sufficient to ensure no future augmentation at the relevant site would be required prior to 2050. In theory, a 'build big' approach makes sense, but only in the instances when there is sufficient confidence that this will not lead to stranded assets.

In recognition of this, where there is a strategic decision to be made on whether to 'future proof' an area of the network, we will carry out economic regret analysis out as part of our CBA to determine the optimum solution that delivers the best value for the consumer. Network solutions that involve anticipatory investment can generate large savings for consumers, but this relies on future need being accurately forecast.

1.5 Our CBA strategy

Our strategic objective is to enable the transition to the low carbon economy, and we have developed four themes that explain how we will achieve that objective. Together these four themes will drive our contribution to cleaner economic growth through decarbonisation, decentralisation, digitisation and democratisation. CBA plays an important role across all four of our strategic themes.

[1] www.theccc.org.uk/publication/net-zero-the-uks-contribution-to-stopping-global-warming/

Figure 3: SHE Transmission strategic themes

Being **stakeholder-led** requires us to be able to communicate the costs, benefits and associated trade-offs of our proposed investments. By applying a consistent methodology to reporting the societal, environmental and economic impacts of our projects via our CBA framework will allow us to engage more effectively with our stakeholders to deliver network solutions that ensure we meet current and future customers' needs.

To ensure we maintain **safe and secure network operation**, we must assess the impact of proposed changes in how we operate and maintain our network. There is a high economic and social cost for households and businesses if their supply of electricity is interrupted, so our CBA framework will help us quantify the potential impact on our customers from activities that need to be carried out to develop a network compliant with the National Electricity Transmission System Safety Quality and Security of Supply standard (NETS SQSS) and maintain greater than 99.99% reliability on our network.

To deliver **sector leading efficiency** means our network must be efficient, affordable to consumers and be open about the trade-offs between cost and investment for local and national benefits. We define efficiency as the minimum use of resources (time, materials, people and money) to achieve a necessary outcome across the whole life of an asset. We also believe consideration should be given to whole system approaches to support the future decentralisation of energy and the clean energy transition. Our CBA framework will help us determine the most efficient solutions that deliver an integrated approach to whole life development and operations.

To ensure **leadership in sustainability,** in line with the commitments set out in our Sustainability Strategy[2], we must be able assess the socioeconomic and environmental impacts of our investments, whether that be through numerical quantification or a qualitative assessment. Our CBA methodology will work in parallel with other sustainability-based metrics so that we deliver network solutions that realise the long-term benefits for society, the environment and the economy. To help measure our progress towards this ambition we will begin reporting on how many projects are assessed through the new framework each year.

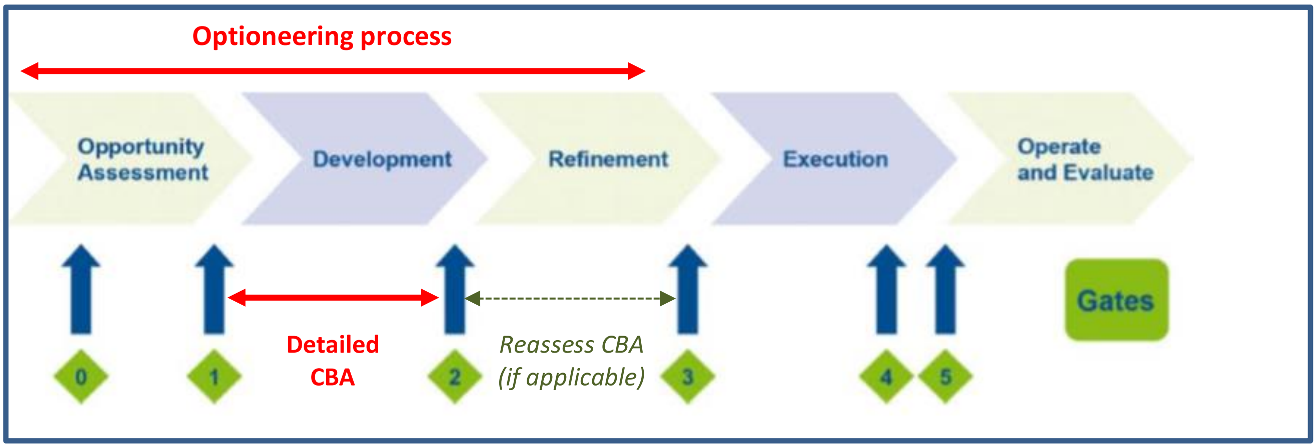
1.6 The use of CBA in project development

Our approach to the development of new infrastructure is governed by our Large Capital Projects (LCP) Governance process. The LCP process has five gate stages, as shown in Figure 4. CBA plays a crucial role in the optioneering process, which comprises the first three phases from Gate 0 through to Gate 3.

Our approach to optioneering, as outlined in our Strategic Optioneering Methodology, is centred around ensuring we build the right infrastructure at the right time, we consider whole system solutions and we deliver value for society and respect the environment. As part of this, we look to identify regional synergies to deliver a robust regional solution.

[2] http://www.ssen-transmission.co.uk/media/2701/sustainability-strategy.pdf

Figure 4: Gate positioning in our large capital projects governance



CBA is one of the main outputs of the optioneering, and analysis is typically carried out during the development phase, after infrastructure development options have been further assessed and more detailed costing, design refinement, including routing assessments and environmental studies have been carried out. A short-list of options is presented to the CBA to assist in the selection of a preferred development option[3]. Further verification of the CBA may be required within the refinement phase if the background drivers for the investment change (e.g. generation drivers, asset condition etc.) which result in a significant change in costs. The refinement phase is where the preferred option is further developed with detailed design completed along with consent application where applicable. Details of the project development gates and corresponding CBA can be found in Table 1.

Table 1: Project development gates and corresponding level of CBA

Gate phase	Gates	CBA analysis	Detail
Opportunity Assessment	0 and 1	Typically, wouldn't carry out CBA due to immaturity of project information	Initial preferred options are identified based on denotative optioneering, considering cost (totex), environmental and technical factors. (e.g. for load related infrastructure investments, this involves identifying preferred route corridors or preferred substation site locations)
Development	1 and 2	Detailed CBA carried out	Further refinement is undertaken on the preferred options, including more detailed design

[3] A note on RIIO-T2 CBA: Given the lack of certainty around generation drivers and future network operability, planning exactly which projects will be executed during the RIIO-T2 price control period is challenging. As per our project development process, we have carried out CBA on those projects that sit within the development phase between gates 1 and 2. For projects between gates 0 and 1, CBA has not been carried out due to the immaturity of the project information.

			refinement, routing assessments and environmental studies, so a more robust CBA can be carried out based upon firmer cost information and up-to-date generation data to determine a preferred option. Verification of the preferred option via the CBA is required before a project can be approved into the refinement stage (i.e. prior to consent application and detailed design and tender process)
Refinement	2 and 3	Reassess CBA (if applicable)	The preferred option is developed with detailed design completed along with consent application, where applicable. Further verification of the CBA may be required within this phase if the background drivers for the investment have changed (e.g. generation drivers, asset condition etc.) which results in a significant change in costs.

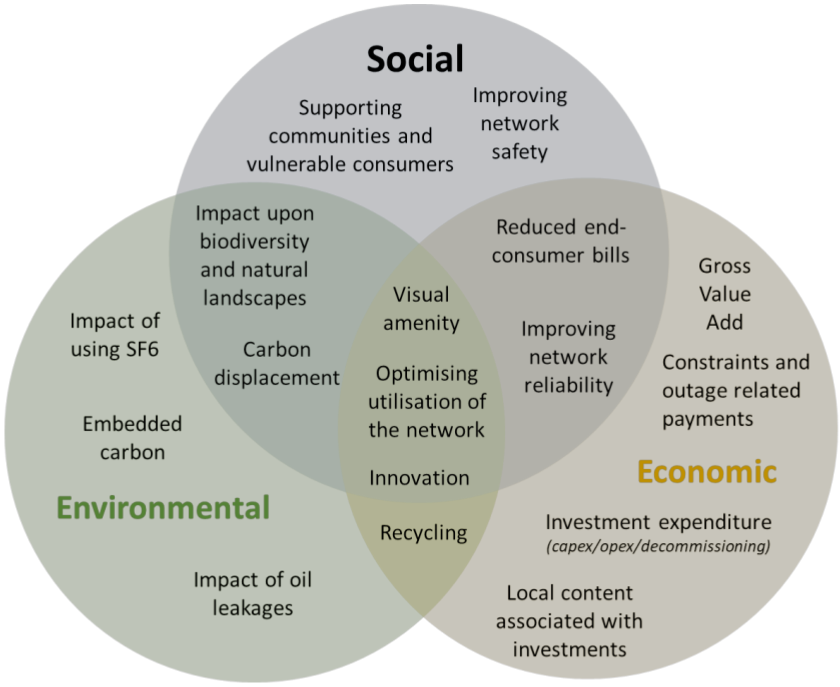
There are instances where CBA is not required as part of the decision-making process. This could be where there are no credible alternative options, i.e. a like-for-like asset replacement, or where there are technically no feasible alternatives. In the instance of there being only one technical solution for installation of a new asset, uncertainty may still exist around site selection, which is not something that can be assessed accurately through CBA due to the subjectivity of allocating values to environmental and land conditions. A qualitative assessment of environmental and ground conditions would therefore be undertaken to derive the preferred solution. In the event CBA is not used as part of the decision-making process, justification for not including it will be captured in project justification documentation.

2 Section 2 – SHE-Transmission CBA framework

2.1 Development of our CBA framework

SHE Transmission carried out extensive research to determine all the costs and benefits associated with our investments. Costs are categorised simply as the expenditure associated with proposed investments (i.e. capex, opex, decommissioning/disposal, and constraint/outage[4] related expenditure), and the benefits, as shown in Figure 5 have been categorised into social, environmental or economic.

Figure 5: Costs and benefits associated with SHE-Transmission investments and ongoing operations



Most benefits cross more than one category, for example, the carbon displacement associated with connecting new renewable generation crosses both social and environmental as there is an environmental benefit from displacing the use of fossil fuels, and a social benefit associated with the improvement of air quality and improving the sustainability of Scotland's and the wider GB energy supply.

[4] Constraint/outage related payments occur when the electricity transmission system is unable to transmit power to the location of demand, due to congestion at one or more parts of the transmission network, which might be because of construction/refurbishment of transmission assets or the network capability is insufficient to transfer the power according to the preference of the market at a particular point in time.

For benefits to be captured in CBA and included in the value of the proposed investment, they need to be monetised (i.e. converted into a GBP sterling value), but this is not always possible. Benefits that are difficult to monetise due to a lack of data, subjectivity of the data, or absence of a proven calculation methodology are described in qualitative terms as they cannot be valued cost-effectively.

These non-monetary benefits must be considered in the assessment of investments and should not be regarded as any less important than the monetary values as they may play a crucial role in the investment decision. Examples of benefits that are not able to be monetised at the moment due to the absence of a proven industry methodology and a lack of data include improving the safety of the network and the impact upon biodiversity. A description of each of the benefits shown in Figure 5, along with details as to whether the benefits have been considered in our CBA framework can be found in Table 2.

Table 2: Further explanation of benefits considered and their inclusion in CBA framework

	Benefit	Description	Details of inclusion in SHET CBA assessment
1	Supporting communities and vulnerable consumers	Delivering what customers, local communities and wider stakeholders require from the electricity transmission network, and the benefits associated with this.	**Our investment appraisal and optioneering process centres around the benefits we can deliver to our customers, local communities and wider stakeholders.** We apply an open and engaged approach to allow everyone to contribute to and understand the reasoning behind our business decisions.
2	Improving network safety	The quantification of the reduction in the probability of injury or fatality on the network because of investment.	**All proposed investments are subject to a rigorous safety review during the optioneering phase** with additional costs included where mitigation is required to minimise the risk of injury/fatality.
3	Improving network reliability	Can be quantified through Energy Not Supplied (ENS) – Ofgem sets targets for each transmission owners' level of ENS to encourage GB Transmission Operators (TOs) to reduce the number and duration of power cuts[5].	**ENS – not quantified in CBA.** To include ENS would require an assessment of the probability of ENS allocated out to individual assets. As SHE Transmission has consistently delivered against ENS targets set by Ofgem, this was not considered material in the CBA.

[5] https://www.ofgem.gov.uk/data-portal/volume-energy-not-supplied-electricity-transmission-riio-t1

4	Impact upon biodiversity and natural landscapes	This would involve: 1. Quantifying the Natural Capital assets – i.e. The natural features within SHE Transmission's ownership; 2. Identifying the ecosystem services that these assets deliver – e.g. Flood management, pollination 3. Drawing on 3rd party open source data to assign an indicative financial value to these services to create a Natural Capital baseline 4. Supports the development of alternative management or enhancement approaches that increase the potential value of our natural assets	**Not currently quantified in the CBA but will be applied once standard industry approach developed.** National Grid and AECOM are currently developing a Natural Capital Valuation tool[6]. SHE Transmission will look to embed a similar approach, once industry position is more developed.
5	Carbon displacement	By connecting new renewable generation, we are displacing the generation of fossil fuels and therefore reducing CO_2 emissions	**Quantified in CBA for new investments that enable the connection of new generation projects using the Scottish Governments Renewable Output calculator[7].** *(For more information see* Appendix 3 – Carbon*)*
6	Reduction in SF6 usage	SF6 is an insulating medium that currently forms the basis of circuit breaker arc interruption systems at all transmission voltages since the 1960s. It has significant environmental disadvantages having a global warming potential of approximately 22,800 times that of carbon dioxide.	**Quantified in the CBA.** The model does not define what specific alternative SF6 technology that will be utilised as this is not yet known by the business. It does assume, where an SF6 alternative is possible to be installed that the carbon impact of this alternative is 0tCO2e. *(For more information see* Appendix 5 – SF_6*)*
7	Project carbon footprint	The carbon emissions produced across the project lifecycle	**Quantified in the CBA.** Estimates included for project lifecycle categories – embodied carbon, construction emissions, operational emissions and decommissioning emissions

[6] https://www.aecom.com/projects/valuing-national-grids-natural-capital-assets/ and https://www.nationalgrid.com/group/responsibility-and-sustainability/environmental-sustainability/natural-environment

[7] https://www2.gov.scot/Topics/Statistics/Browse/Business/Energy/onlinetools/ElecCalc

			(For more information see Appendix 3 – Carbon*)*
8	Reduction in oil leakages	Aging transformers can be prone to oil leaks which can have a detrimental impact on the environment and incur cost due to oil needing to be replaced.	**Not quantified because data co-relating leakage and age/condition not available or captured.**
9	Recycling	Relates to the recycling of materials/assets.	**Included within costs in CBA.** We work with our contractors to ensure recycling of scrapped materials takes place, where applicable. Disposal costs included in the CBA include the net benefits of scrappage.
10	Innovation	Any cost savings associated with innovations will be incorporated into costs within the CBA.	**Included within costs in CBA.**
11	Optimising the utilisation of the network	This relates to: 1. Our ability to deliver whole system approaches and support the decentralisation of energy supply. 2. Electrical losses – through refurbishing existing assets or replacing/installing new assets using more efficient technology, there will be fewer losses on the network than might otherwise arise. This will save consumers money, and lead to a reduction in carbon.	**Whole system approaches are considered in our project development process** however, increased alignment between the transmission and distribution businesses will help support the transition towards delivering whole system solutions. **Reduction in losses will be quantified in the CBA when methodology agreed for quantifying unit cost of losses agreed across GB network operators.** *(For more information see* Appendix 6 – Losses*)*
12	Visual amenity impact	The impacts high voltage transmission grid can have on the visual amenity of landscapes, which is a concern for stakeholders.	**Included within costs in CBA.** A visual impact assessment is carried out as part of the optioneering phase within the project development process.
13	Reduced end-consumer bills	Through our strategy to build the right infrastructure at the right time and consider whole system solutions, we will create a more efficient network, resulting in cost savings for the end consumer.	**Included within costs in CBA.** Delivering best value for the end-consumer is the key driver behind our optioneering, so cost savings will be built into the CBA via consideration of low-cost options.
14	Gross Value Add (GVA) and local content associated with investments	GVA is the measure of the value of goods and services produced in an area, industry or sector of an economy. It is a measure of total output and income in the economy and provides	**Quantified in the CBA for both SHE Transmission investments and for the new generator connections enabled by SHE Transmission activities.**

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		the monetary value for the amount of goods and services produced in an economy after deducting the cost of inputs and raw materials that have gone into the production of those goods and services.	*(For more information see* Appendix 7 – Gross Value Add*)*
15	Constraints & outage related payments	Constraint/outage related payments occur when the electricity transmission system is unable to transmit power to the location of demand, due to congestion at one or more parts of the transmission network, which might be because of construction/refurbishment of transmission assets.	**Quantified out with the CBA by Electrical System Operator (ESO) where required.** Where constraint/outages have a significant impact upon the investment decision, input typically sought from the ESO to assist with calculations.
16	Investment expenditure	Includes operational, capital, decommissioning and disposal costs.	**All costs associated with the initial investment and the lifetime operation of the assets are included in CBA.**

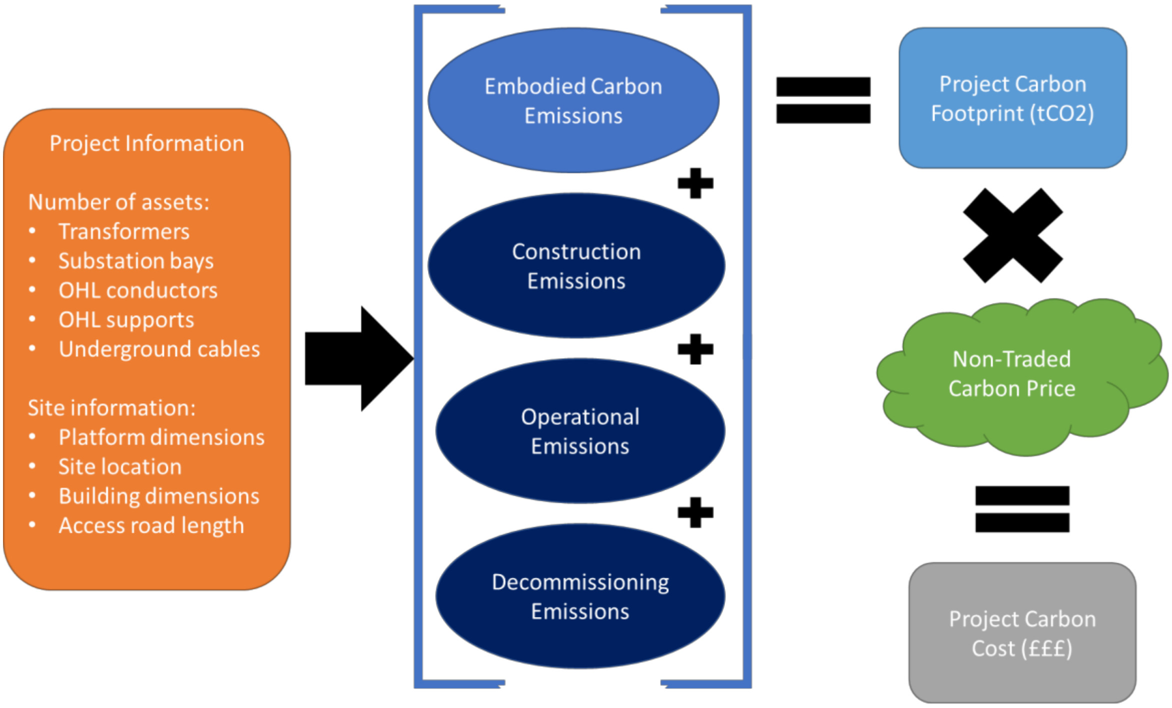
2.2 Carbon valuation

2.2.1 Lifecycle carbon valuation in CBA

We are committed to managing resources over the whole asset lifecycle – including embodied carbon (i.e. the manufacturing of assets), construction, operations and decommissioning activities – to reduce our greenhouse gas emissions in line with climate science and become a climate resilient business. It is our aspiration that the carbon lifecycle cost of investment options plays a key role within our project development (between gates 1 and 2) and is considered in the selection of a preferred solution. We have therefore developed an internal carbon pricing model that estimates a carbon cost to each option considered in our CBA through deriving values for the main emissions areas across the asset lifecycle.

Figure 9 outlines the high-level calculation steps applied within our carbon pricing model to determine the carbon cost of each of the options considered in our CBA. In terms of carbon price, we use the Department for Business, Energy and Industrial Strategy (BEIS) central, non-traded carbon price (as the emissions are outside the scope of the EU Emissions Trading Scheme), but the model does include the functionality to calculate the cost based on different prices.

Figure 6: Carbon pricing model



To reduce our greenhouse gas emissions, we must first establish an awareness of the carbon impact of our investments – our carbon price model allows us to do this. With this information, we can then identify those areas, or specific types of projects, that are the most carbon intensive and develop strategies to lower the carbon impact. It is our vision to embed carbon considerations within our strategic optioneering and project development processes, which will require us to determine a way of flagging high carbon options within our CBA outputs.

We are currently exploring approaches to this, but one way could be to categorise options using high/mid/low carbon impact ratings based upon the ratio of the carbon cost to project TOTEX (capex and opex), and how sensitive this ratio would be to an increase in the cost of carbon (Table 3). We will continue to develop our thinking in this space and would support collaboration across the GB TOs and the regulator to align reporting on the carbon cost of transmission network investments.

Table 3: carbon impact ratings

Option carbon cost impact ratings		
Low	increases in carbon price would have a limited impact on this project	< 10 %
Medium	increases in carbon price would have a moderate impact on this project	10-29.9%
High	increases in carbon price would materially affect this project	> 30%

To ensure our modelling is fit for purpose for indicating the lifecycle carbon emissions for investment options, we had third party consultants carry out a high-level peer review. Our consultants, who are experts in carbon evaluation, were satisfied the model covers the main elements required for developing a carbon footprint for the sort of infrastructure that is applicable to the SHE Transmission business; i.e.:

- embodied emissions associated with purchased goods, including replacement materials/equipment associated with maintenance over a 45-year lifetime;
- the construction process including materials, services and transportation;
- ongoing operation; and
- decommissioning.

The carbon cost of each option assessed in the CBA will also be reported using the same categorisations as in our Science Based Target[8] (SBT) reporting. We have committed to setting an SBT by summer 2020 in response to our stakeholders, and shareholders, wanting us to take ambitious action on climate change and reduce our emissions by following best practice in climate science, which includes setting a Science Based Target (SBT).

2.2.2 Carbon displacement

As well as reporting on the carbon cost of our investments, we also calculate the estimated carbon that will be displaced for load projects that will enable the connection of new renewable generation onto our network. As the proportion of renewable electricity in Scotland grows it gradually displaces the need to generate electricity from polluting fossil fuels, reducing total carbon emissions. Using a methodology based on the Scottish renewable energy output calculator[9] we can estimate the tonnes of CO_2 that will be saved per year through the new renewable generation that we connect, and then assign a value to this using the non-traded carbon price.

[8] Setting a SBT involves companies setting targes to reduce greenhouse gas emissions in line with what the latest climate science says is necessary to meet the goals of the Paris Agreement – to limit global warming to well-below 2°C above pre-industrial levels and pursue efforts to limit warming to 1.5°C. Setting a SBT will provide us with a clearly defined and transparent pathway that specifies how much and how quickly we need to reduce our emissions. Success will be achieving our SBT and we are committed to report annually to our stakeholders on progress. www.sciencebasedtargets.org/

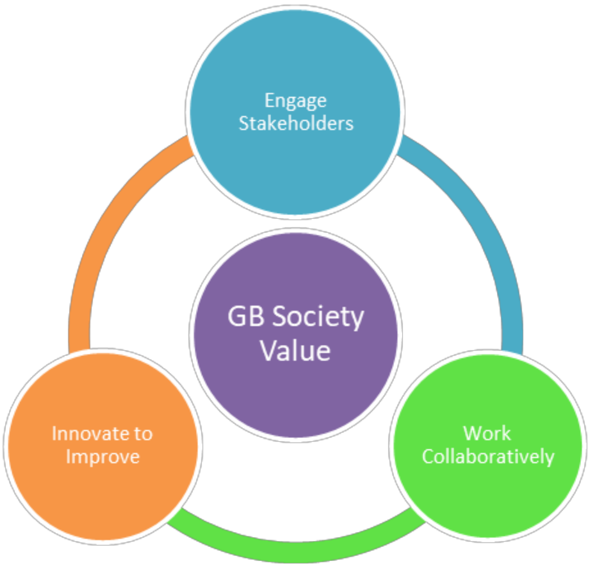
[9] https://www2.gov.scot/Topics/Statistics/Browse/Business/Energy/onlinetools/ElecCalc

2.3 A whole system approach

Our GB electricity system is undergoing a period of sustained change driven by our commitment to a net zero economy by 2050 (2045 in Scotland). New technologies are driving new ways of producing and consuming energy. How we generate and distribute that energy is becoming increasingly important, ensuring we do so in a sustainable and economic manner. The challenges associated with this span not only the electricity industry, but also the transport, gas and heat industries as we transition to a net zero economy. It therefore makes sense to work across the GB energy networks to identify how best to meet these challenges and support the overall transition.

To deliver whole system solutions, a new approach to system planning and development is needed – we need to be able to appropriately compare transmission asset-based solutions with solutions on the distribution network, or alternative flexible and market-based solutions that can deliver better value, whether that value is economic, social or environmental. This will likely necessitate changes in the standards and frameworks that we adhere to in system planning and operations. The complexity of these required changes should not be understated and as such, significant further analysis and discussion with the ESO and the regulator will be required before new ways of working can be implemented.

GB Society Value sits at the heart of a whole system approach – key to this is quantification of the value of whole system solutions through CBA. It is our aim, during RIIO-T2, that we establish a clear set of parameters that allows us to implement whole system CBA which will give transparency to our assessment and decision-making processes.



It must be noted that assessing the benefits of network solutions that deliver outputs on both transmission and distribution networks is complex due to business separation. Although SSE Plc. Distribution and Transmission businesses operate under the same RIIO regulatory framework, there are differences in outputs and incentives making it difficult to align benefit assessment. As outlined in our Whole System Policy, we are committed to developing whole system CBA. Increased alignment between the SSE transmission and distribution businesses will support the identification and adoption of alternative approaches to network development and where these can deliver better value, whether that value is economic, social or environmental.

2.4 Willingness to pay and CBA

Willingness to Pay (WtP) is simply a measure of the economic value of goods and services, whether traded in competitive markets, provided without markets, or in a regulated market. Being a regulated monopoly, visibility of the actual market choices of the end consumer is limited, so WtP research helps inform the economic value consumers give to services, which in turn can be used to influence our investment decisions.

As a provider of an essential public service in the North of Scotland, understanding end bill payers' views on WtP for services can help inform and justify investment. To inform these valuations in our CBA, SHE Transmission took part in a joint study carried by NERA Economic Consulting on behalf of the GB Transmission Operators to establish WtP valuations. The study was conducted via a targeted survey of end consumers and it generated estimated customer valuations for a range of service attributes, as outlined in Figure 7.

WtP formed a critical piece of RIIO-T2 stakeholder engagement, revealing that customers are willing to pay for enhanced reliability, environmental initiatives, visual amenity improvements, supporting communities, biodiversity and revealing their preferences. The findings will be applied qualitatively alongside other evidence, including other stakeholder feedback, to triangulate our policy decisions, test our emerging policy position and inform our strategic options. The study has provided significant information on priorities for investment and incentive applications in our RIIO-T2 plan.

Figure 7: WtP service areas

2.5 Stakeholder engagement

On the 13th of June 2019 we hosted a Cost Benefit Analysis webinar to seek feedback on our CBA framework and present on how we developed our approach. There was wide stakeholder representation with participants from Ofgem, National Grid Transmission, National Grid Electrical System Operator, Scottish Power Energy Networks, Edinburgh University, Strathclyde University, Yorkshire Water, Scottish National Heritage and SHE Power Distribution. The questions asked, and feedback provided are shown in Table 4.

Table 4: CBA webinar questions and summary of feedback

	Question	Summary of feedback
1	Do you agree our CBA methodology fits within our four strategic themes?	There was agreement that our methodology fits within our themes.
2	Do you think our CBA framework includes the relevant social, economic and environmental benefits to allow us to deliver the best solutions for our customers?	There was agreement that our framework does consider the relevant costs and benefits. Comments were made around the quantification of whole system benefits which is something we will be developing on the lead up to and during the RIIO-T2 price control period.
3	How important are the wider societal benefits inclusion within the framework?	There was agreement that it is valuable to include societal benefits within CBA, but there needs to be

		clear traceability and verification of underlying calculations/assumptions to ensure a robust approach.

3 Section 3 – CBA modelling

3.1 Modelling tools and related documentation

All CBA has been carried out using the RIIO-T2 CBA Excel model provided by Ofgem, which applies HM Treasury's Green Book approach to project appraisal[10]. The model provides Ofgem with a common reference point that can be used to compare projects across GB Transmission Operators. The defined costs and benefits captured in the Ofgem model are shown in Table 5, but the model does provide the user with the ability to add in other benefits not prescribed within the Ofgem model.

The outputs of the CBA will be captured in investment justification papers which are to be submitted to Ofgem for all proposed investments throughout T2. These papers provide a summary of the proposed investment, details of the optioneering process, what cost benefit analysis has been carried out as well as a summary of the stakeholder engagement that has been carried out relating to the project.

Table 5: Ofgem CBA model costs and benefits

Costs	Ofgem defined benefits
• Investment expenditure (capex, opex, decommissioning/disposal) • Constraint/outage costs	• Reduction in losses and the associated cost saving and linked to this. • Reduction in carbon emissions associated with losses valued using the traded carbon price. • Reduction in emissions associated with using SF6 alternatives. • Reduction in oil leakage, and the associated £/litre of oil savings. • Reduction in the probability of fatality and non-fatal injury. • Reduction in monetised risk (see Appendix 8 – Network Asset Risks Metrics (NARM) and Monetised Risk)

3.2 Types of investments that require CBA

SHE Transmission's proposed RIIO-T2 investments fall broadly into two main categories – load and non-load. Load expenditure relates to changes in generation or demand using our network, whereas non-load expenditure

10 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/685903/The_Green_Book.pdf

is triggered based upon condition assessments of network infrastructure or operability concerns or improvement opportunities.

Expenditure is further classified into core and non-core, where core expenditure relates to transmission network expenditure and non-core relates to indirect business activities or operations. Table 6 shows the different investment types and the approach we have taken to carrying out CBA.

Table 6: Investment types and CBA details

Investment category	Investment type	CBA details
Load	Load core investments relate to developing our network capacity to accommodate changing patterns of energy use, such as connecting new generation or accommodating shifting demand.	CBA has been carried out on projects that sit within the development phase between gates 1 and 2. For projects between gates 0 and 1, CBA has not been carried out due to the immaturity of the project information.
Non-load	Non-load, core investments relate to the maintenance or replacement of assets that are damaged or at the end of life.	CBA has been carried out on all proposed T2 projects.
	Non-core, non-core investments which cover costs associated with the performance of the system (e.g. managing high levels of intermittent generation which can impact power quality, managing black start capability).	Due to the nature of these investments where the benefits are not easily quantifiable, CBA is not always the most applicable method of project appraisal for selecting the best investment option so is only used where applicable quantification permitted.
	Non-load, non-operational relates to investments that are not directly related to the core operations of the company e.g. IT system upgrades.	Due to the nature of these investments where the benefits are not easily quantifiable, CBA is not always the most applicable method of project appraisal for selecting the best investment option so is only used where applicable quantification permitted.

3.3 The different approaches to CBA calculations

There are different types of CBA depending upon the type of investment:

1. **Counterfactual NPV assessment –** this involves establishing a baseline (i.e. the counterfactual position) which can be compared to the different investment options. The value-add from each investment

option compared to the baseline will inform the selection of the preferred option. The baseline position is an investment option in itself. This approach is used where the proposed investment relates to reinforcing the network (i.e. developing our network capacity to accommodate changing patterns of energy use, such as connecting new generation or accommodate shifting demand), replacing or refurbishing existing assets. Where we have an obligation to connect new generation due to our statutory licence obligations, there might not be a comparable counterfactual position to compare the options to. In this instance a comparative NPV assessment of the cost and benefits of each option would still take place. See Appendix 1 – Counterfactual NPV assessment for full calculation steps for this approach.

2. **Least Worst Regrets (LWR) –** this is used in decision making whenever it is difficult or inappropriate to attach probabilities to possible future generation scenarios. The "regret" is the difference in the value between the decision made and the optimal decision, given the realisation of a generation scenario. LWR provides a recommended investment option based on minimising the worst-case regret. For example, if Option A has an NPV of £500m and Option B an NPV of £450m, the regret of choosing Option B over Option A is £50m. The regret of choosing Option A is zero. The approach provides a series of regrets for each transmission option under each generation scenario. The highest (worst) regret is then determined for each reinforcement option – the option of least worst regret is the one that returns the lowest worst regret. See Appendix 2 – Least Worse Regrets for full calculation steps for this approach.

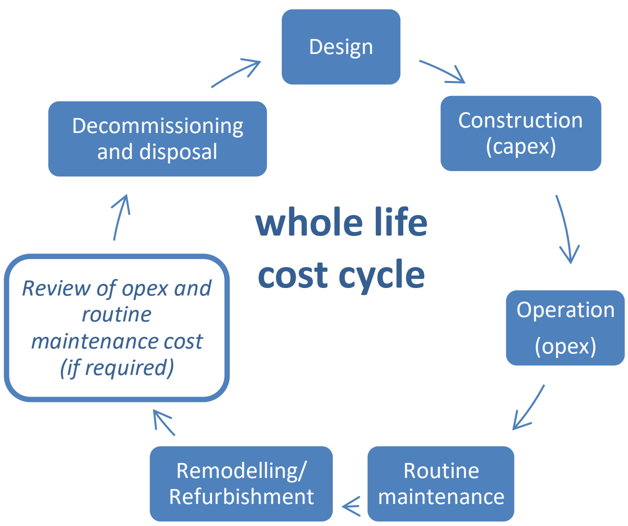
Recognition must be given to our statutory licence obligations; especially as far as new connections are concerned. We are obliged to prepare offers to connect new generation projects to the transmission network and, if these offers are accepted, proceed to develop and deliver the works associated with the connection. It might therefore be the case, in some instances, that the Net Present Value (NPV) of the new projects is negative, given the capital costs involved in connecting the new project.

3.4 The incorporation of whole life costing in CBA

In all our CBA modelling for RIIO-T2, consideration has been given to the whole-life costs. This approach has allowed us to fully assess the financial risks of taking long term responsibility of proposed investments. Opex estimates have been generated for lead assets only[11]. It is often the case that in the initial stages of a project the focus is often around driving down initial capital cost, with longer-term maintenance and operating costs given little consideration. We believe the systematic consideration of all relevant costs and revenues associated with the construction and operation of an asset throughout its whole life outlined in Figure 8 provides many benefits including:

1. Encourages the analysis and questioning of business requirements helping to optimise decision-making and avoid costly specification mistakes.
2. Optimises the total cost of ownership by balancing the initial capital outlay with the ongoing running costs leading to better value-based decisions.
3. Ensures future maintenance and operational requirements are understood and factored into the upfront decision-making.
4. An understanding of the key drivers behind the whole life cost can help to unlock opportunities for innovation.

Figure 8: whole life cost cycle



[11] Lead assets consist of: transformer, reactors, underground cables and Overhead lines. Overhead line is made up of tower/wood pole/composite pole, conductor and fittings.

4 Appendices

The appendices provide addional detail around specific elements considered within SHE Transmission's CBA framework and, if applicable, the methodology applied to incorporate them into CBA calculations.

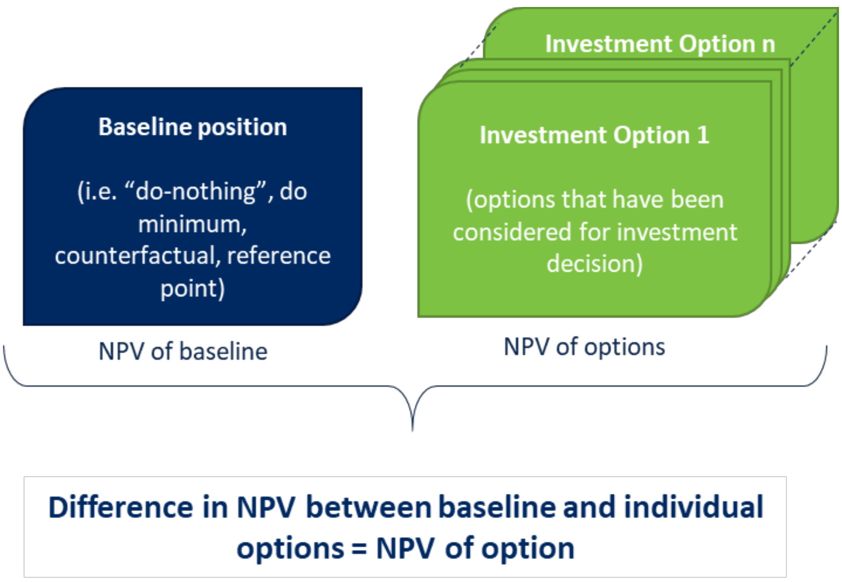
4.1 Appendix 1 – Counterfactual NPV assessment

The calculation steps for carrying out a counterfactual NPV assessment are as follows:

1. **Define the baseline position, as well as the possible investment options**

   Identify the costs associated with the baseline position (i.e. pre-investment status quo). This generates the counterfactual position which is then used as the baseline for comparison purposes. The value of each investment option is compared to the value of the baseline, and the delta in these is the value of carrying out the investment (see Figure 9).

Figure 9: counterfactual NPV calculation



2. **Identify relevant costs and benefits**

   Costs and benefits are classified in the following manner:

   - Costs (capital, operating expenditure, disposal/decommissioning, constraint costs resulting from outages)
   - Tangible (e.g. SF6 impact, embedded carbon, carbon displacement)
   - Intangible (e.g. social benefits i.e. Gross Value Add, visual amenity, impact upon biodiversity and natural landscapes)

3. **Predict costs and benefits over relevant period (i.e. 45-year asset life)**

Analysis is carried out over the period when the costs and benefits will occur, which for transmission assets is defined as a 45-year lifespan.

4. **Convert costs and benefits into common monetary value, where applicable**

   To turn outcomes from projects into a financial benefit that can then be used in the cost benefit analysis, outcomes/benefits/costs should be monetised and expressed in the same monetary unit to enable comparison across the different options and across different options where possible. However, not all benefits can be monetised, for example the impact upon biodiversity and natural landscapes. A qualitative assessment of these benefits should be considered in the assessment of the different investment options.

5. **Calculate NPV of options**

   To determine the present value of the costs and benefits for use in calculations of overall efficiency and benefit cost ratios, the values of future costs and benefits are discounted to current prices. The CBA model uses Social Time Preference Rate (STPR) discounting method whereby the value attached to society of investing sooner is more than what would be attached in the future. A standard discount factor of 3.5%, as stipulated in HM Treasury's Green Book for the first 30 years of investment, then 3.0% thereafter. Calculations also take account of capitalisation of assets and depreciation over the 45-year asset life as prescribed under the RIIO regulatory framework.

6. **Sensitivity analysis**

   To provide a greater understanding to decision makers who will be using the outputs of the CBA, sensitivity analysis can be carried out to understand whether changes in the data and assumptions in the model has a significant effect on the outputs of the CBA. Data in the model should be adjusted to more pessimistic or optimistic values to understand the impact on the value of the investment. There are several potential scenarios that can be run. For example, changing the timing of the investment to take advantage of planned system outages, or considering a wider regional approach regarding timings of new generation connections to protect against the installation of assets that may become stranded in the future.

7. **Make recommendation of investment option**

   Based upon the results of the NPV analysis, and any accompanying qualitative evidence that may not captured in the CBA calculation (i.e. stakeholder engagement, past project experience), a recommendation can be made on the preferred option.

8. **Internal review and governance checks on results**

All CBA working is subject to rigorous internal peer review and senior management sign-off.

4.2 Appendix 2 – Least Worse Regrets

Investments requiring least worst regrets analysis typically have multiple options that need to be assessed across future scenarios which will typically comprise generation scenarios. For example, an investment might have a baseline option, plus two other investment options for three generation scenarios. This would result in nine LWR scenarios being considered, as illustrated in Figure 10.

Figure 10: LWR illustrative example

LWR scenarios

Investment options
Baseline
Option 1
Option 2

Generation scenarios
Generation scenario 1
Generation scenario 2
Generation scenario 3

Baseline - Generation scenario 1
Baseline - Generation scenario 2
Baseline - Generation scenario 3
Option 1 - Generation scenario 1
Option 1 - Generation scenario 2
Option 1 - Generation scenario 3
Option 2 - Generation scenario 1
Option 2 - Generation scenario 2
Option 2 - Generation scenario 3

The calculation steps for carrying out a LWR assessment are as follows:

1. **Carry out counterfactual NPV assessments across all LWR scenarios**.

   In the illustrative example in Figure 10, there would be six counterfactual NPV calculations carried out:

   - Option 1 - Generation scenario 1 vs. Baseline - Generation scenario 1 (A1)
   - Option 1 - Generation scenario 2 vs. Baseline - Generation scenario 2 (A2)
   - Option 1 - Generation scenario 3 vs. Baseline - Generation scenario 3 (A3)
   - Option 2 - Generation scenario 1 vs. Baseline - Generation scenario 1 (B1)
   - Option 2 - Generation scenario 2 vs. Baseline - Generation scenario 2 (B2)
   - Option 2 - Generation scenario 3 vs. Baseline - Generation scenario 3 (B3)

2. **Determine highest NPV for each generation scenario**

   In the example, establish the highest NPV out of A1 &. B1 (=H1), A2 & B2 (=H2), A3 & B3 (=H3)

3. **Calculate least worst regret**

   This is calculated by establishing the difference between the NPV for each option/generation scenario and the highest NPV for that generation scenario, which would involve calculating the following: A1 – H1, A2 – H2, A3 – H3 for option 1 and B1 – H1, B2 – H2, B3 – H3 for option 2.

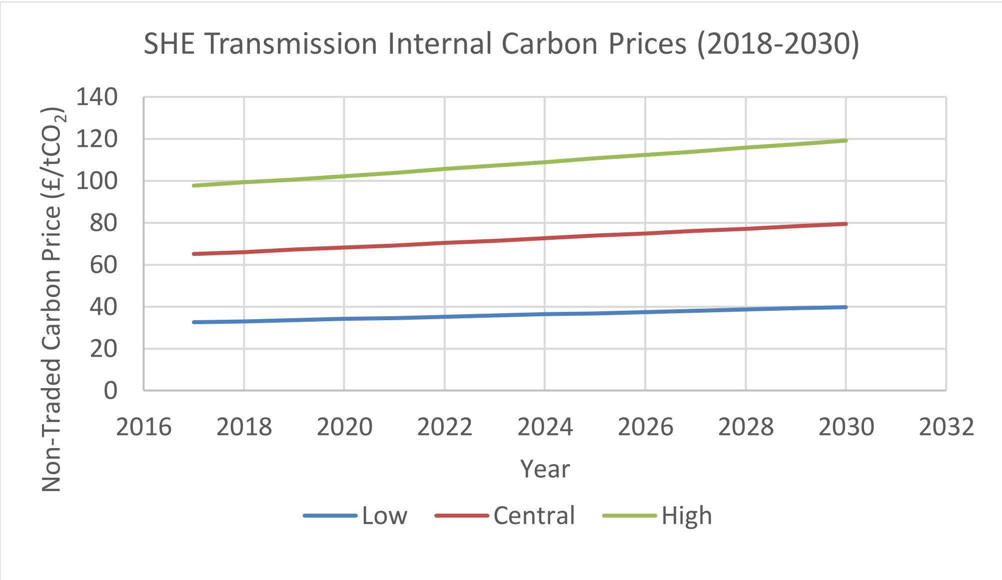
4. **For each option, calculate the worst regret**

   Using the results from the calculations in step 3, identify the option that has the worst regret i.e. lowest NPV. The option with the least worst regret (i.e. the smallest comparative regret) is usually deemed the preferred option.

4.3 Appendix 3 – Carbon

The Department for Business, Energy and Industrial Strategy (BEIS)[12] has calculated non-traded carbon prices out to 2100 using high, central and low estimates. Figure 11 shows the forecast increase in carbon prices between 2018 and 2030. Our carbon pricing model uses the central pricing forecast to value the emissions across the project lifecycle, based on the relevant year in which they are estimated to be produced.

Figure 11: SHE Transmission internal carbon prices based on BEIS estimates



4.3.1 Project lifecycle carbon impact calculation methodology

To estimate the carbon emissions across the project lifecycle we have focused on the following four lifecycle categories:

1) Embodied Carbon
2) Construction Emissions
3) Operational Emissions
4) Decommissioning Emissions

12 Table 3 - https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal (December 2017)

Our carbon pricing model uses inputs on the number of assets and civil works to provide carbon emission estimates for each of these categories in tonnes of CO2 equivalent (tCO2e). A summary of the main emission areas estimated within each of these categories is described below.

1) **Embodied Carbon** – estimates the carbon emissions associated with the production and manufacturing of electrical assets (e.g. transformers, substation bays, OHL) and civil materials (e.g. structural steel, concrete, aggregates).
2) **Construction Emissions** – estimates the carbon emissions associated with construction and installation activities, primarily from fuel use for construction plant and the transportation of assets and materials to site.
3) **Operational Emissions** – estimates the carbon emissions associated with operational activities over the 45-year design life of the transmission assets. This includes emissions from operational transport (for inspection and maintenance), substation electricity use and sulphur hexafluoride leakage.
4) **Decommissioning Emissions** – estimates the carbon emissions associated with the decommissioning of the transmission assets at the end of their design life.

The sum of the above emissions provides the total project carbon footprint. This value multiplied by the BEIS non-traded carbon forecast price to produce the project carbon cost. This provides project managers with a view of the carbon impact of proposed investment options. The information can also be used to forecast how the project would be affected by growth in carbon prices over its lifetime.

A high project carbon cost can serve as an indicator of where the project would potentially be misaligned with a business Science-Based Target (SBT) for emissions reduction. In this regard it can be used to incentivise the project manager/engineer to pursue lower carbon options on the project (e.g. route/site/technology/asset choice).

We are currently investigating how we can embed carbon pricing within our strategic optioneering process. One option would be to compare the carbon cost to the TOTEX for the individual options being assessed in our CBA. Our carbon modelling calculates this ratio, which can be fed through a red-amber-green (RAG) scoring system to provide an indication of the carbon intensity of the project (Table 7).

Our thinking of what rating would be deemed acceptable for different project types is in its early stages. We will continue to develop our knowledge in this space and would support collaboration across the GB TOs and the regulator to align reporting on the carbon cost of transmission network investments.

Table 7: carbon impact ratings

Option carbon cost impact ratings		
Low	increases in carbon price would have a limited impact on this project	< 10 %
Medium	increases in carbon price would have a moderate impact on this project	10-29.9%
High	increases in carbon price would materially affect this project	> 30%

4.3.2 Carbon displacement

Load related projects will enable the connection of renewable generation schemes. The electricity generated from these schemes will displace the carbon emissions associated with the UK electricity grid mix, resulting in a carbon saving which can be quantified. Using the capacity of the connected schemes (in megawatts) as an input, we can estimate the carbon emissions (in tCO_2e) that would be avoided as a result of our project enable these schemes to connect. This uses a methodology similar to the Scottish renewable energy output calculator[13] but which also includes a declining UK grid mix factor, accounting for the growth of renewables on the UK energy network.

[13] https://www2.gov.scot/Topics/Statistics/Browse/Business/Energy/onlinetools/ElecCalc

4.4 Appendix 4 – Constraints

Constraint/outage related payments occur when the electricity transmission system is unable to transmit power to the location of demand due to congestion at one or more parts of the transmission network. This may arise when the market would see more generation output seeking to use a part of the network than the network capacity available at that particular time or, in another instance, when network users' access has to be restricted as a result of construction/refurbishment activities. The payments are associated with the compensation made to the generators that are unable to transmit power which are determined through the contractual arrangements agreed with the ESO.

The inclusion of constraints within transmission planning is becoming more important as a result of increasing levels of connected renewable generation in the north of Scotland leading to potential for greater constrained volumes. In addition to this, there are various developments being carried out on existing assets related to enhancing the capacity of existing overhead line circuits by, for example, reconductoring or voltage uprating which result in lengthy construction outages while the enhancement is delivered.

Historically, the quantification of constraint payments has always required input from the ESO as SHE Transmission does not have access to the system balancing data used to understand the impact of increased renewable connections, or the contractual terms that dictate the £/MW value paid to the generators experiencing the constraints. This analysis is also labour intensive so SHE Transmission typically only seeks input from the ESO on large boundary transfer projects to enable effective comparison across delivery strategies.

In short, the following information is needed to calculate constraints when there is a local boundary impact as a result of works:

1. Duration of outage to determine length of time generators will be constrained i.e. the number of days the generator will be constrained over the period of works, which could extend over multiple years.
2. Total MW capacity constrained (taking into consideration load factors)
3. £/MW rate paid by the ESO to generators to compensate for outages.

As the CBA model is annual, constraint costs need to be on an annual basis for the duration of the works. For each year, the following calculation is required:

$$constraints = no. of\ days\ x\ MW\ constrained\ x\ £/MW\ rate$$

SHE Transmission has obtained input from the ESO for those RIIO-T2 projects where there will be significant boundary transfers but is exploring methods of assessing constraints internally in light of the increasing importance of managing constraints on the network. As we increase our focus on developing a whole system approach, it is our intention to develop our own methodology for quantifying constraints which will allow more comprehensive and insightful assessment of options before engaging the ESO.

4.5 Appendix 5 – SF_6

SF_6 is an insulating medium that currently forms the basis of circuit breaker arc interruption systems at all transmission voltages since the 1960s. The use of SF_6 circuit breaker technology replaced other arc interruption techniques such as the use of bulk oil or air blast circuit breaker technologies.

Whilst SF_6 technology is inherently safer and more reliable compared to bulk oil or air blast circuit breakers, it has significant environmental disadvantages. SF_6 is one of the four greenhouse gases (GHGs) captured under the Kyoto Protocol. It has a global warming potential of approximately 22,800[14] times that of carbon dioxide and is one of the more potent GHGs. Recording and reporting the management of SF_6 is controlled by the Fluorinated Greenhouse Gases Regulations 2015.

In recent years, manufacturers have developed circuit breakers with SF_6 alternatives, such as G^3 or H2 or Airplus as an insulating medium. These alternatives to SF6 circuit breakers have significant environmental advantages as they are not greenhouse gases and the impact of carbon is almost negligible in comparison to SF_6 (Table 8).

Table 8: Circuit breaker insulating mediums and the associated global warming potential relative to carbon dioxide.

Insulating Medium	Global warming potential relative to carbon dioxide
SF_6	22,800
G^3	326
H2	6
AirPlus	1

Non-SF6 circuit breakers are still experimental and innovative, and in RIIO-T2, SHE Transmission will be looking to test different SF_6 alternative circuit breakers on the network.

As non-SF_6 alternative circuit breakers have the potential to have significant benefits in terms of reduced carbon emissions, this will be included as a benefit within the CBA where applicable. The approach SHE Transmission has adopted is as follows:

1. As SF_6 alternatives are under-going development by manufacturers it will not be known at this stage which SF_6 alternative will be adopted for particular projects. Where there is a technically and

[14] http://naei.beis.gov.uk/overview/pollutants?pollutant_id=SF6

commercially viable alternative, and subject to CBA, we will no longer install SF_6. Therefore, SHE Transmission have assumed that the reduction in carbon for a SF_6 alternative circuit breaker is equivalent to the amount of carbon that will be removed from not installing a SF_6 circuit breaker. SHE Transmission have not considered the carbon impact of SF_6 alternatives since the carbon impact of the other alternatives is negligible in comparison (Table 8).

2. The amount of SF_6 within circuit breakers which is used to derive the carbon impact of SF_6 is shown in Table 9. SHE Transmission derived these values based on analysis of all the circuit breakers on the network. These values are common with values that have been used within the implementation of the Network Asset Reliability Measures (NARMs) methodology which was calibrated with National Grid Electricity Transmission and Scottish Power Transmission.

Table 9: Amount of SF6 within circuit breakers

GIS / AIS	Voltage	Amount of SF_6 (kg)
AIS	400kV	260
AIS	275kV	64
AIS	132kV	23
GIS	400kV	775
GIS	275kV	274
GIS	132kV	87

Scottish & Southern Electricity Networks

4.6 Appendix 6 – Losses

Transmission losses refer to the energy that is lost as electricity is transmitted across the transmission network from generation to directly connected demand or a grid supply point[15]. Generally, for a fixed type of line/cable/voltage; the greater the distance energy has travelled, the greater the energy lost during transit. Therefore, the locational variability of losses is an important factor for generation and demand in particular locations. Elexon suggest that transmission losses account for just under 2% of all electricity transmitted[16].

Losses in transmission systems are, largely, a function of the current carried by the conductors. The loss experienced in a conductor carrying alternating current is given by the equation I^2R, where I is the current and R is the resistance of that conductor. This resistance causes energy to be absorbed by the conductor which results in the conductor heating up in the same way as an electric bar heater or the element in a kettle. This energy is lost to the surroundings. Reducing losses contributes to greater energy efficiency and since the cost of losses is passed on to the consumer, we need, to take transmission losses into consideration when developing the transmission network and, where appropriate, when assessing that investments are well founded.

Increased renewable generation connections in Scotland has led to increased peak network transfers and therefore to higher transmission losses. Power flow studies are used to determine the impact of the proposed load related reinforcement projects on transmission losses.

Against a background of increased network transfers, achieving a reduction in total network losses would not be economic or efficient. However, we are working to reduce the losses associated with each unit of energy transmitted across our network by considering losses and wider environmental impacts when evaluating options for reinforcements or asset replacement.

We are working with other network operators to establish a methodology to determine a unit cost for losses which incorporates the direct financial cost to consumers as well as the environmental impact. Once this methodology has been established, SHE Transmission will build it into its CBA methodology. For more information please see SHE Transmission's Losses Strategy.

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[15] The level of Transmission Losses from the licensee's Transmission System, measured as the difference between the units of electricity metered on entry to the licensee's Transmission System and the units of electricity metered on leaving that system

[16] https://www.elexon.co.uk/documents/training-guidance/bsc-guidance-notes/transmission-losses-2/

4.7 Appendix 7 – Gross Value Add

GVA is the measure of the value of goods and services produced in an area, industry or sector of an economy. It is a measure of total output and income in the economy and provides the monetary value for the amount of goods and services produced in an economy after deducting the cost of inputs and raw materials that have gone into the production of those goods and services.

SHE Transmission has developed an Excel based GVA modelling tool to assess the potential regional (Scottish) benefit of specific transmission investments as well as the accompanying renewable generation enabled (onshore wind, offshore wind and tidal etc.).

The following methodology is followed in the model to determine GVA (also summarised in Figure 12):

1. Project expenditure is categorised into three key groupings – development costs, capital costs and operating costs (including decommissioning). Transmission Capex is based on SHE Transmission estimates while renewable energy capex will be based on £/MW assumptions.

2. The proportion of 'regional content' in the original investment is calculated based on a range of relevant studies for Scotland[17].

3. These costs are then deconstructed into relevant Office of National Statistics (ONS) Standard Industry Classifications (SIC)[18].

4. Regional input-output multipliers[19] published by the ONS for the Scottish Government are used to measure the expected change in total output following an increase in final demand for a relevant

[17] Onshore Wind: Economic Impacts (RenewableUK) http://c.ymcdn.com/sites/www.renewableuk.com/resource/resmgr/Publications/Reports/onshore_economic_benefits_re.pdf , Economic benefits from onshore wind farms (BVG Associates), https://bvgassociates.com/wp-content/uploads/2017/09/BVGA-18510-Economic-impact-onshore-wind-report-r3.pdf, Onshore Wind Direct & Wider Economic Impacts (RenewbableUK) https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/48359/5229-onshore-wind-direct--wider-economic-impacts.pdf

[18] https://www.ons.gov.uk/methodology/classificationsandstandards/ukstandardindustrialclassificationofeconomicactivities

[19] https://www2.gov.scot/Topics/Statistics/Browse/Economy/Input-Output/Downloads/IO1998-2015Latest

sector's output. Change is the sum of the stimulus' direct effect on that sector as well as its indirect effects on other sectors through production interdependencies.

5. Total benefits are assessed over the economic life of the asset (45-year asset life for SHE Transmission investments and interconnectors, 20 years for windfarms and solar farms), and discounted to 2019 using the social time preference rate as published in the HMT Green Book[20].

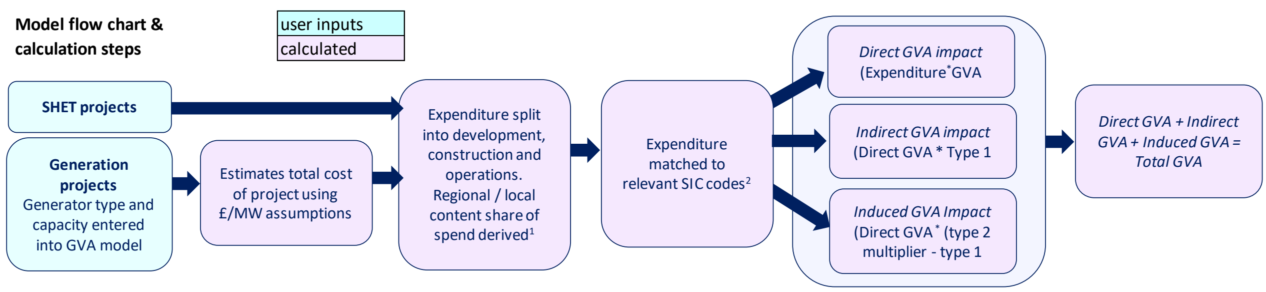
Total GVA is calculated at three levels:

1. Direct GVA: value generated from direct project expenditure

2. Indirect GVA: value generated from employment of sub-contractors and demand for goods and services from suppliers down the supply-chain

3. Induced GVA: value generated from greater demand and spending on goods and services such as accommodation, food, fuel and retail by employees who are employed as a result of the direct and indirect impact.

Figure 12: GVA model methodology flow chart



[1] Assumptions based on various sources

[2] Standard Industrialisation Classification (SIC) codes are used by government bodies such as Companies House and the Office for National Statistics to systematically identify and categorise the principal business activities of limited companies operating within the UK

[3] GVA output ratio % is calculated as GVA effect / GVA multiplier, based upon Scottish Government's Input-Output tables

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20 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/685903/The_Green_Book.pdf

4.8 Appendix 8 – Network Asset Risks Metrics (NARM) and Monetised Risk

Non-load related asset investment is triggered on a risk basis where the risk of an asset is derived using the Network Asset Risks Metric (NARM) methodology. This methodology was developed by all UK electricity transmission owners (TOs) in collaboration with Ofgem. It allows TOs to assess the risk of assets on the transmission system and to demonstrate that they are investing in the right areas to manage that risk effectively[21]. The NARM methodology calculates asset risk separately for each lead asset. Lead assets consist of transformers, reactors, circuit breakers, underground cables and overhead lines (conductors, fittings, and towers).

The types of non-load investment that can be applied to manage the performance of the transmission system range from routine maintenance to full replacement. At the highest level, there are four options for intervention for each lead plant type which have the following definitions:

- Repair – activities which take place on detection of a defect or after a fault and return the asset to its pre-fault condition and asset life.
- Maintenance – activities to achieve the asset life and ensure asset performance. Maintenance would not be expected to extend asset life.
- Refurbishment – activities that change asset condition and / or extend asset life.
- Replacement – replace an asset in its entirety that is in a state requiring replacement.

SHE Transmission use a Condition Based Risk Management (CBRM) system to assess the risk of every lead asset on the transmission network. This system takes a range of asset and site-specific information and applies the methodology to create a monetised risk figure, which can be used to start the process of prioritising asset interventions.

The outputs from CBRM, along with operating experience will be used to identify the assets that require investment in T2. Once SHE Transmission has determined which assets require investment the CBA will be carried out to determine the optimal solution, based on credible investment options, for example replacement

[21] https://www.ofgem.gov.uk/publications-and-updates/notice-intention-not-reject-modified-electricity-transmission-network-output-measures-NARMs-methodology

of a transformer in-situ or offline. The CBA for non-load related investment will follow the same approach as load-related investment, with the addition of a lifetime benefit which is a measure of the long-term risk benefit from investment in an asset.

The NARM methodology will be used to derive the monetised asset risk reduction that can be expected with and without an intervention over the lifetime of the intervention. This will enable the lifetime benefit of the investment to be derived and compared between different intervention options (for example replacement against refurbishment) and different assets.

Figure 13 illustrates how the NARMs methodology and CBAs are used to identify and justify non-load asset investment.

Figure 13: NARMs methodology

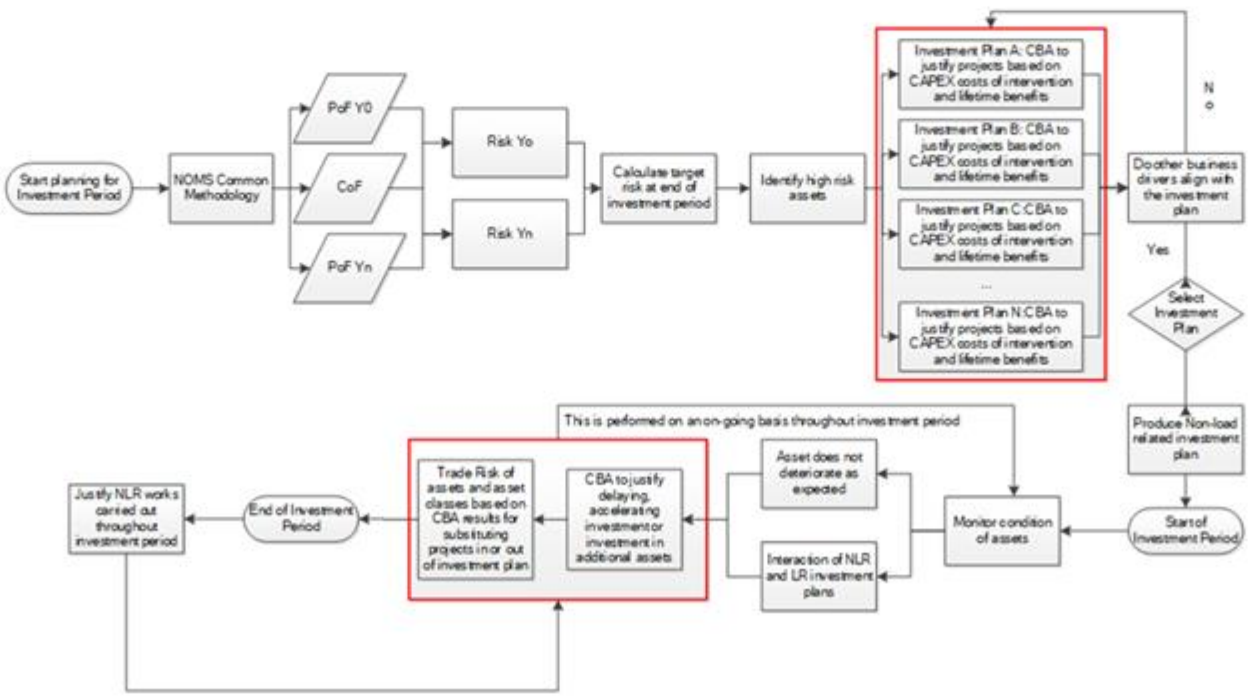

Figure 13 illustrates how the NARMs methodology is used to derive asset risk and how it is used in the creation of a non-load business plan, and throughout the price control.

4.8.1 Risk Calculation

The risk of an asset is defined as the likelihood of an event and the consequences of the occurrence,

$$Risk = Probability\ of\ Failure\ x\ Consequence\ of\ Failure$$

where the probability of failure represents the likelihood that the asset will have a failure requiring the asset to be replaced, and the consequence of failure represents the impact of the asset failure.

When the likelihood is expressed as a probability and consequence as a cost, then using the risk equation provides a risk cost. This risk cost enables the risk of assets to be ranked, and the risk across different asset classes can be compared.

The consequence of failure is a monetised value for each of the underlying consequence of failures:

- System: this is a measure of an asset's importance in terms of its function to the transmission system. It is measured in terms of system related costs incurred by the electricity sector if that asset was to experience a failure. The system costs are split into two categories; customer costs and system operator costs, however, all these costs are recovered through the consumer.
- Safety: when assets fail, they have the potential to cause harm to both the public and personnel who work on or near to the assets. In these circumstances there is an incurred cost. The safety consequence therefore captures the safety risks that deteriorating assets present to individuals who are exposed to their effects and the associated cost to society.
- Environmental: when assets fail, they have the potential to impact on the local area to the asset or to the wider environment. The aim of this part of the methodology is to capture the environmental risks that deteriorating assets present to the environment and the associated cost to society.
- Financial: this represents the amount it would cost SHE Transmission to replace or repair the asset.

Although the consequence of failure, and therefore risk, is monetised, this does not correspond to the cost that SHE Transmission will incur if the asset was to experience a fault. It is instead a measure of the impact of the asset failure on society and the electricity network. By monetising the consequence, it allows each of the consequences to be relative to each other, and the consequence which has the greatest impact at a site will drive investment.

The probability of failure is based on a combination of the condition of the asset and historical experience of failures. The condition of the asset is based on a catalogue of information which includes:

- Location information: where is the asset located, as location and altitude will have an impact on the condition of the asset as closer to the coast the asset will experience more corrosion than asset further inland, and assets at a higher altitude will be more exposed to harsher weather conditions.
- Results from inspections and condition assessments: this can include visual condition assessment results, and results from oil tests.
- Historical experience from operating the asset: this includes SF6 leakage.

4.8.2 Calculation Methodology

To evaluate the lifetime benefit, the methodology will be used to derive the monetised asset risk with and without an intervention over the lifetime of the asset. This will enable the relative risk reduction to be compared between different interventions (for example replacement, refurbishment, and increased OPEX costs) and different assets. The lifetime benefit will be calculated as a ratio of the costs to the risk reduction.

Within the non-load CBA, the costs and benefits of credible investment options will be compared to the "do nothing" option. "Do nothing" represents business as usual, and no capital investment will be applied to the asset. This option will assume that inspections, maintenance and condition assessments are performed at current levels of frequency and reactive maintenance is carried out when required. It is assumed that the asset under the "do nothing" scenario will be replaced at the end of its operational life. To determine the end of operational life the NARM methodology has been used. Within the NARM methodology an End of Life modifier (EoL) for every asset can be calculated which provides an indication of the health of the asset. The EoL goes on a scale from 0.5 to 10, and the End of Life of an asset will be when the asset reaches an EoL of between 6 and 10. Typically the End of Life of the asset is defined as EoL greater than 7, and any asset which has an EoL above this value asset will not be allowed to remain operational, as the risk to the system would be too great.

The risk of the asset under the "do nothing" and intervention options can be used to determine the lifetime benefit of investment. The monetised risk is calculated for each year over for the life of the asset. The monetised risk is used to calculate the survival risk of the asset, which corresponds to the risk of the asset experiencing a catastrophic failure weighted by the probability that the asset will survive. The lifetime risk benefit of an Option is then calculated by comparing the survival risk of the Option with the "do nothing" survival risk. The "do nothing" scenario assumes that when the asset experiences a catastrophic failure the asset is replaced. The lifetime benefit is an aggregation of the risk of all lead assets being considered within the project scope.

The monetised consequence value of the failure of an asset should be assumed to be fixed during the assessment period for the cost benefit analysis purpose for a like for like intervention. The exceptions to this would be when the asset replacement brings an environmental or safety benefit, for example

- Replacing an AIS circuit breaker with a GIS circuit breaker
- Replacing an oil-filled cable with an XLPE cable
- When replacing an asset, locating it indoors rather than outdoors.

4.8.3 Monetised risk and decision making

As mentioned previously, one of the fundamental benefits of implementing a monetised risk-based methodology is the ability to express the risk on the network as one discrete value. Not only can we compare risk across asset classes using the same "currency", but we can better measure our performance against asset risk targets regardless of the type of works being carried out.

4.9 Appendix 9 – OPEX

The inclusion of OPEX within CBA allows SHE Transmission to fully assess the whole-life financial implications associated with the proposed investment. It means that the lifetime maintenance and operational requirements are fed into decision making which will enable better value-based, long-term decisions.

OPEX estimates are included for lead assets only and correspond to the costs associated with maintaining and inspecting assets on the network. SHE Transmission have policies detailing the inspections and maintenance regimes carried out on assets. These policies[22]are created by Asset Management which have experience in managing the assets on the network, as well as Operational departments which have experience in operating assets on the SHE Transmission network[23].

SHE Transmission have used the policies detailing the inspections and maintenance regimes as the basis for estimating OPEX costs over the life of an asset (i.e. over 45 years). For each inspection and maintenance activity the lifetime cost has been established and then spread annually. Some costs are easier to estimate than others – for example, SHE Transmission incurs a fixed cost for a transformer oil test, however, inspection and maintenance costs can vary depending on the manufacturer and asset model due to the resource required. For these types of costs, SHE Transmission has a database recording the resource required to inspect and maintain associated lead assets. The average of these costs for each lead asset category has been used to represent the resource time required for the activity, and this was combined with the average hourly rate in order to estimate a cost for the activity.

The following is a list of high-level assumptions in the OPEX costs, detailed assumptions are listed within the CBA:

- OPEX estimates only covers costs directly associated with the lead asset. General substation inspections and maintenance is excluded, for example, maintenance of associated protection and civils.

[22] TG-NET-GOV-XXX: Transmission Asset Management Plans for Inspections, Maintenance and Condition Assessments
[23] Lead assets consist of: transformers, reactors, underground cables, and overhead lines. Overhead lines are made up of a structure (tower / wood pole / composite pole / trident line), conductor and fittings.

- For substation lead assets (transformers, reactors and circuit breakers), the maintenance cost covers resource, materials and plant.
- For overhead lines, the maintenance costs correspond to resource only, and excludes any plant or materials that may be required. It is calculated on a span basis and differentiates between steel towers, wood poles and composite poles.
- OPEX resource estimates only cover the time to carry out the activity and does not include travel time to site.
- Inspections and maintenance costs corresponds to the average cost of the asset type.
- Only included routine OPEX, any ad-hoc OPEX has been excluded.

4.10 Appendix 10 – Biodiversity and natural landscapes

As a responsible developer, we want to make sure our environmental impacts are minimised, and that permanent habitat loss and associated value is understood, compensated and mitigated in better ways that provide a net positive contribution. We have a responsibility to protect and promote the natural environment and ensure development expenditure is undertaken in a sustainable manner now for the benefit of future generations.

Promoting our natural environment encompasses many areas including (but not limited to) biodiversity, natural processes, landscape change and visual amenity. Through our development activities, we consider a wide range of natural environment aspects at each stage of our work. In relation to sensitive species and habitats, the linear nature of our new and existing networks provides real opportunities to actively improve the connectivity between important habitat types and ecosystems, but it is equally important to ensure that such linear corridors do not act as ecological barriers.

This is important as an abundance of habitats and species of conservation value are reducing year on year, so much so that the UN has set strategies that aim to halt and reverse this trend. The Scottish Government has also set out its "Scottish Biodiversity Strategy" that sets out its vision, objectives and desired outcomes[24] [25].

Whilst biodiversity is valuable in its own right, it is also crucial to the maintenance of natural systems on which we all depend (for example: pollination of crops, flood management and air quality regulation). Protecting and enhancing biodiversity is therefore an essential element of a truly sustainable society.

As such, our ambition is to ensure that our activities not only maintain the existing balance that exists, but help to enhance the biodiversity in our area, targeting a net gain. Our projects also have a visual impact on the natural environment. To address this, we will ensure that the visual impact of new infrastructure is fully considered in our projects from conception and is reduced as far as practical in line with our social, environmental and economic cost benefit analysis.

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[24] Scottish Executive. (2004). Scotland's Biodiversity: It's in Your Hands. Scottish Executive, Edinburgh http://www.scotland.gov.uk/Publications/2004/05/19366/37239

[25] Scottish Government, (2013). 2020 Challenge for Scotland's Biodiversity: A Strategy for the conservation and enhancement of biodiversity in Scotland. Scottish Government, Edinburgh http://www.gov.scot/Resource/0042/00425276.pdf

There is not yet a standard industry approach for assigning a financial value to the impact on biodiversity and the natural capital, therefore this has not been incorporated in our current CBA modelling. We are working with National Grid to establish a methodology and would look to apply in the future.

A high-level indicative view of what this methodology might look like is:

1. Quantifying the Natural Capital assets – i.e. The natural features within SHE Transmission's ownership;
2. Identifying the ecosystem services (ES) that these assets deliver – e.g. embedded carbon, Flood management, pollination;
3. Drawing upon 3rd party open source data to assign an indicative financial value to these services to create a Natural Capital baseline.

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