Investment Decision Pack

NGET_A8.02 Generation

December 2019

As a part of the NGET Business Plan Submission

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Engineering Justification Paper
Load Related – Generation Connection

Primary Investment Driver	Generation Connections (including Storage & Interconnectors)		
Reference	NGET_A8.02 Generation		
Location in main submission narrative	Chapter 8 – *We will make it easier for you to connect and use the network* Section 5.1 i) *Invest in our network to connect generation, storage and interconnector customer*		
Cost	£245.0m		
Delivery Year(s)	2021 – 2026		
Reporting Table	B series tables and totex cost-matrix tables		
Outputs in the T2 period	15.3GW of generation connections in T2		
Spend Apportionment	**T1**	**T2**	**T3**
	£145.2m	£245.0m	£57.0m

**All costs are in 18/19 prices unless otherwise stated.*

Contents

Executive Summary

Our Business Plan proposes a baseline allowance of £245.0m to connect 15.3GW of generation, storage, and interconnector projects during the T2 period. We have robust processes in place to ensure that appropriate investment development is undertaken at the right time; that stakeholder views, including the Electricity System Operator, are taken into account; that scope and cost estimates are robust; and that lessons learnt are captured and incorporated in future projects. This paper describes these processes and justifies 99% of the proposed baseline allowance, through five detailed case studies of the investment decisions we have made and 20 individual cost benefit assessments.

It is inappropriate to make unit cost comparisons (£/MW) between projects expected to be delivered in T1 and proposed baseline for T2 because the proposed mix of projects anticipated to connect in the T2 period is very different (and consistent with the Common Energy Scenario). Well designed and calibrated uncertainty mechanisms will ensure allowances adjust appropriately should the mix of customer projects change from that assumed and provide an incentive to minimise investment costs.

1. Introduction

The need for new connections, and the associated network investment, arises from customer applications to connect to the transmission system. Upon receipt of an application, National Grid assesses the customer's request and identifies the most economic and efficient solution to facilitate their connection. Up to three months after the application an offer is made to the customer (via the Electricity System Operator). Once the offer is signed by the customer, the investment is progressed through our Network Development Process (NDP).

New customer connections can drive a variety of different network investments. This justification paper focuses on local investments, rather than those on the wider network to reinforce major system boundaries. Depending on the nature of the connection (e.g. the technology type), these local investments can be made up of connection assets (those forming the immediate connection to the transmission substation and capable of use by only one customer, treated in T1 as an Excluded Service); or assets beyond the connection charging boundary known as local infrastructure assets (funded in T1 by a baseline allowance and adjusted by a generation uncertainty mechanism).

As investments progress through our NDP, we continually assess the likelihood of the customer investment delaying or cancelling. Where we assess there to be a high risk of a customer not proceeding with their project, we will seek to minimise and / or delay our expenditure where possible. To inform this process, a regular report is provided to our investment committees to show the relative viability of our customer's own projects against the financial commitment we are making.

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2. Generation Connections in RIIO-T1

The baseline for T1 was set using the 2012 Gone Green energy scenario, with adjustments made for edge effects and ensuring a consistent operation of the uncertainty mechanisms[1]. The underlying capacity of connections anticipated for T1 was 26GW. The following table summarises the underlying baseline and latest view of T1 capacity, allowance, and spend for generation connections.

	Capacity (GW)	Allowance (£m)	Spend (£m)
RIIO-T1 Baseline / Business Plan	26	1388	1863
RIIO-T1 Latest Forecast	13	416	670

The reduction in forecast (based on six years of actuals and two years of forecast) has been driven by changes in customer requirements. Key changes include:

- the rapid and unanticipated growth in embedded generation and, in particular, small and medium scale solar generation; and
- the delay of new nuclear power stations and large offshore wind farms, that have depended on financial support that has not (yet) been forthcoming.

While spend has reduced as a result of these changes, so too have our allowances. Through the operation of the T1 uncertainty mechanisms, generation allowances have reduced by £972m[2], resulting in spend being £252m higher than adjusted allowances. There are two main drivers for this:

- the mix of projects now proceeding require more investment than those originally considered when the average UCA was set. We estimate this has led to a £58m overspend against allowances; and
- we have incurred costs of £194m on projects that do not deliver an output before 2022/23 (the so-called RIIO-T1+2 period, eight years of T1 plus the first two years of T2) because customers have either terminated or the output is beyond this period.

It is difficult to systematically determine the efficiencies that have been delivered by load related investments because allowances have been adjusted by an uncertainty mechanism based on an average unit cost. However, we have identified £264m of specific efficiencies in the generation portfolio, of which £132m relates to projects delivering outputs in T1. Most of these efficiencies relate to steps we have taken to reduce the scope of our investment; but significant contributions have been made through working with the supply chain and changing the commercial codes that drive investment. We have incorporated these learnings, where applicable, in our T2 business plan.

[1] The baseline set by Ofgem was 33GW
[2] Excluding adjustments for TPG

3. Developing and Costing projects

National Grid established the NDP to ensure a consistent approach to project development is applied to all investments (the same process applies to customer-driven and asset health-driven investments) and provide a rigorous governance framework to ensure the right development activities are undertaken at the right time, before moving on through the process and incurring additional costs. The process is characterised by stages of activity (boxes) and governance gates (diamonds), as shown in Figure 1.

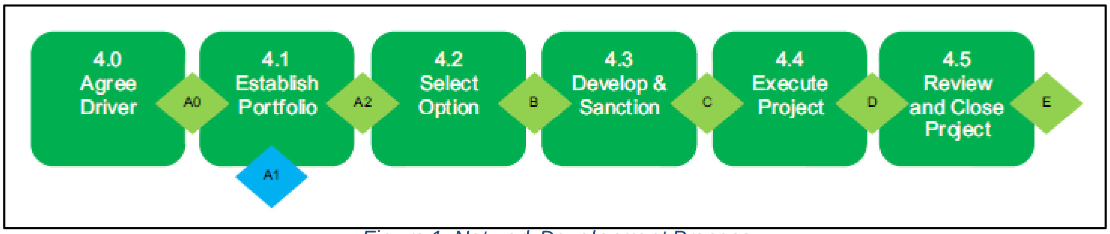

Figure 1: Network Development Process

A gate keeper is assigned to each of the gates with accountability for determining whether sufficient development has been undertaken (by reference to an agreed check-list) and whether the time is right to move to the next process stage (which is informed by the underlying driver of the investment and the timescales of future development).

Typically, projects progress linearly from one stage to the next. However, there are instances, particularly for customer-driven investments, where projects may go forward or backwards one or more stages. For instance, a customer that terminates their project may move from Stage 4.2 to Stage 4.5 so that the investment can be closed; or a customer may change its connection requirements during Stage 4.3 (via a new application) such that it might be appropriate to return to Stage 4.2 to review the option selection.

Stage 4.0 – Confirm and Agree Driver

This stage records the driver for an investment and the outputs that are expected to be delivered. Typical drivers include connecting a new customer, removing constraints on system boundaries, or maintaining compliance with industry codes and standards. Once a driver has been established, the investment will proceed to Stage 4.1. For customer offers, Stages 4.0 and 4.1 are often combined.

Stage 4.1 – Establish the portfolio by creating an initial plan entry

The aim of this stage is to establish and maintain a portfolio of all potential investments required to meet our customers' needs and identify high-level investment costs and development milestones. This is the first building block from which investment scenarios can be created for business planning purposes. In the case of generation and demand connections, this phase of work will be undertaken during the three-month connection offer process with input from a scheme team that encompasses a wide range of engineering and commercial disciplines.

At the end of this stage an initial project scope will have been outlined and costed (this will include lead assets and the typical non-lead assets that are associated with this, considering the likely investment context e.g. if an existing substation is being extended or if a new site is required); initial resource estimates made; and a series of future milestones identified to ensure that subsequent development and construction activities meet the customer's requirements. Options and issues for consideration in future stages of development may also be identified and recorded.

All investment costs at this stage are based on a Cost Book and expenditure phased using pre-defined spend profiles. The Cost Book provides a list of standard transmission assets and development activities, and the average unit cost to procure and / or install these. The costs provided by the Cost Book are based on delivered and tender returns and it is updated annually. The phasing considers the likely complexity of the work (e.g. if a development consent order will be required) and the type of assets being installed (e.g. a transformer or overhead line).

When the milestones indicate that it is necessary to begin more detailed development (which, for connection offers is when the customer signs their contract), the project is presented to Gate A2 and, if successful, moved into Stage 4.2.

Stage 4.2 – Option Selection

The purpose of this stage is to identify a full range of options that satisfy the driver (whist complying with industry codes and standards, and recognising any request from the customer to deviate from this, where permitted, through a 'design variation' customer request) and to select a preferred option by identifying with more certainty the scope, programme, costs and issues associated each of these potential options. This work is usually in the form of obtaining existing records and site information, and then undertaking desktop assessments. The stage will identify a variety of different ways the driver could be met, including: no-build and less-build solutions (if they are available); use of innovative or emerging technologies (e.g. use of new conductor types); choices such as on-line versus off-line build and air-insulated versus gas-insulated solutions; the application of any lessons learnt from similar previous projects; and the current ratings different assets and technologies provide. During this stage we will also considered the availability of whole system options, if that has not already been assessed through another process, which are covered below.

The options are then assessed to identify a preferred option. Options are costed using the Cost Book. When decisions are finely balanced, a more detailed cost benefit analysis (CBA) is undertaken. Option selection considers our anticipated investment costs as well as non-economic issues such as impact on the environment (e.g. noise impacts) and the challenges gaining the necessary consents (for example, the impact on specific listed animal / bird species, and sites of special scientific interest or areas of outstanding natural beauty).

In the case of connection for offshore wind farms and interconnectors, there are two stages of option selection. First, a process to determine the optimum onshore connection point, then a process to optimise the design of the agreed onshore connection. The first phase of this delivers a Connection and Infrastructure Options Note (CION)[3] and involves extensive close working between the customer, other transmission owners, and the electricity system operator (ESO). The purpose of the CION is to ensure that the best whole system solution is selected and progressed.

The CION process considers the investment costs of the customer, the onshore and offshore TOs (where relevant), and the ESO's constraint management costs for a range of connection locations. The ESO then undertakes a cost benefit analysis to establish the least worst regret option. In undertaking this work, a range of different energy backgrounds are considered consistent with the published Future Energy Scenarios[4] (FES). Economic considerations are augmented by other technical considerations such as deliverability, technical issues, and consentability.

Once a preferred option is selected and it is right to commit resource to develop and sanction the selected option, the project is presented to Gate B and, if successful, moves into Stage 4.3.

[3] https://www.nationalgrideso.com/document/45791/download
[4] http://fes.nationalgrid.com/fes-document/

Stage 4.3 – Develop and Sanction

During stage 4.3 further work is undertaken to develop the preferred option to the level of accuracy required to achieve financial sanction and move into the tender and delivery stage. Survey works (e.g. noise assessments and asbestos surveys) and further detailed design work (e.g. engineering drawing production) is undertaken to establish a comprehensive project scope, identify and address hazards, and ensure resources are in place to deliver the project (including system access).

At the end of this stage, the design will be costed using a bottom-up assessment and a full quantitative risk assessment (QRA) undertaken. The level of detail and accuracy determined by the stage is sufficient for National Grid to undertake a rigorous assessment of tender returns and subsequently ‘baseline’ the investment to monitor progress during the delivery stage.

Once this stage is completed the investment is then taken forward for full financial sanction approval by the relevant investment committee. Provided the driver is still firm (e.g. customer commitments are being fulfilled), it will then be presented to Gate C and if successful move into Stage 4.4.

Stage 4.4 – Execute Project

This stage encompasses the delivery activities ranging from tendering and contract award through to physical construction work and commissioning. Throughout this stage our contractors are monitored to ensure the projects are delivered according to the agreed scope and cost.

Once the construction activities are completed, all financial matters settled (e.g. contract claims closed), lesson learnt captured and consolidated, and systems updated (for example, to ensure the correct maintenance occurs in the future), the investment is ‘closed’ by the relevant sanctioning authority and presented at Gate D. If successful, the project is moved into Stage 4.5.

Stage 4.5 – Review and Close Project

The purpose of this stage is to provide final confirmation that the investment elements have been closed in all business systems, and that all reported costs are final and complete. Once this assurance has been received, the investment process is complete.

This stage, in conjunction with the investment sanctioning committee, will also identify projects that should be subject to a Post-Investment Appraisal (PIA). A PIA is used for challenging investments to review decisions and ensure that appropriate lessons are learnt.

4. Engagement of the ESO during design & delivery

The ESO is engaged extensively during the design stages (in particular, Stage 4.0 to 4.2, when the preferred option is selected). NGET is accountable for developing a solution that meets all stakeholder’s requirements. To ensure that the ESO is involved during this key phase, weekly meetings are held with the ESO to update them on progress and raise any commercial or engineering issues that may arise before a customer offer is finally made. Following legal separation, NGET provides a draft offer to the ESO around 60 days after the customer’s application has been received, so that any remaining issues (mainly commercial rather than engineering) can be resolved before the three-month offer deadline is met.

NGET keeps the ESO appraised during project delivery and periodically provides information to the ESO, so that its and the customer’s financial exposure can be assessed and managed, as well as monitoring progression against agreed contract milestones.

5. Establishing efficient costs and scope

As described in the preceding section, the NDP uses a Cost Book during the early development (Stages 4.0 to 4.2) to determine the investment costs (i.e. for each asset type included, the calculation is: number of assets required x unit cost of asset). This approach to costing projects has been used to determine 62% of the baseline expenditure. The unit cost of key assets in the Cost Book has been recently benchmarked by external consultants. In more than half of the assets assessed, the consultants found the unit cost was below the industry average. In cases where the unit cost was between the industry average and maximum, we have included efficiency savings in the plan, to align our unit costs with the industry average. The review found no assets had unit costs above the industry maximum. Details of the study and the methodology used can be found in Chapter 14 'Our total costs and how we will provide value for money' and NGET_A14.02 TNEI Asset unit cost methodology review annex.

In addition to ensuring the unit costs are efficient, we also ensure the designed scope of the schemes are efficient. This takes places in a series of design reviews. For customer connections, these typically occur once during the offer stage (Stage 4.0 / 4.1); and again, during development and sanction stage (Stage 4.3). Design reviews are intended to examine the safety, cost and environmental impacts of our projects throughout their entire lifecycle from design and construction through to operations, maintenance and final decommissioning. At these reviews, independent and experienced engineers challenge the engineering design decisions that have been made by the project teams, to ensure that minimum scope has been included. For some investment types, a checklist might be used to test whether lean design decisions that have been made in the past can be applied to similar investments being reviewed.

6. Development assumptions and risks

Assumptions are inherent in a process that increases our understanding of the scope of an investment as it passes through successive development stages. A key assumption during the early stages of development (typically Stages 4.0 to 4.2) is to assume a typical project scope and costing this using the Cost Book. However, as development continues, these assumptions are refined until the scope is fully understood and costs have been determined on a bottom-up basis. There are some exceptions to this. For instance, an investment may currently reside in an early development stage but has had detailed development undertaken because it progressed through later stages for a customer that is now delayed. The same investment may, however, be of use for another customer but whose project is at an earlier stage of the NDP.

The main risks to projects are:

- the customer project does not proceed at the anticipated rate or terminates. The consequence of this is that unnecessary costs may have been incurred. To mitigate this risk, customers make a financial commitment to transmission investment (through the ESO), which encourages them to delay their connection before significant transmission costs are incurred. National Grid also monitors customer projects and milestone compliance to provide further comfort about the customer's progress and align this (to the extent possible) with our own investment. We have also championed industry code changes that, if implemented, would pass the cost of customer-driven delays back to the customer, to protect consumers from these costs.

- planning permission may not be received, might be delayed, or could be conditional. These risks are inherent in projects that require substation extension or new / altered overhead lines. To mitigate these risks National Grid identifies potential consenting issues early (e.g. designated land, endangered species, and visual impacts) and has developed good relationships with landowners and consenting authorities, so these issues can be addressed during scheme development.

- system access may not be available, which might affect the date of delivery or the way in which construction is undertaken. National Grid works closely with the ESO throughout the development process to reduce this risk. This starts by booking ‘provisional’ outages during the early stages and making ‘firm’ bookings during Stage 4.3, so that transmission work can be accommodated. These bookings are reviewed throughout the project life. Where there are issues with transmission access, we will consider different delivery methods (e.g. circuit diversions or quicker return to service arrangements) or request the ESO reviews its risk position and / or jointly assess the cost-benefit of additional delivery costs verses the ESO’s system management costs.

Each project has its own specific risks. Therefore, for each project with a detailed cost-benefit analysis, we have included a project-specific risk assessment.

7. Generation Background for our Business Plan

Our Business Plan is fully consistent with the low-end Common Energy Scenario that has been developed by network companies across the energy industry (including transmission and distribution, and gas and electricity sectors), with support from the ESO to provide consistency with the FES published in 2018.

The supply mix in England and Wales is likely to see a substantial level of change over the T2 period, driven by digitalisation, decarbonisation, and decentralisation. Whilst there is over 46GW of generation and interconnectors contracted to connect over the T2 period, the Common Energy Scenario estimates only 15.3GW of this will connect over this period. The Common Energy Scenario anticipates the following high-level trends:

- growth in decentralisation will continue, leading to new generation and storage connections that are much smaller than traditionally observed;
- the requirement to replace capacity lost through power station closures (e.g. coal-fired generation by 2025) will lead to a need for new gas-fired generation to meet demand;
- continued decarbonisation leads to new offshore wind and some nuclear connections; and
- a continued desire for increased access to European energy markets driving an increased level of interconnection.

Figure 2 summarises the energy background for England & Wales that drives our Business Plan expenditure and outputs delivered during the T2 period. In all categories, our planning assumptions sit at the low-end of the industry-agreed Common Energy Scenario.

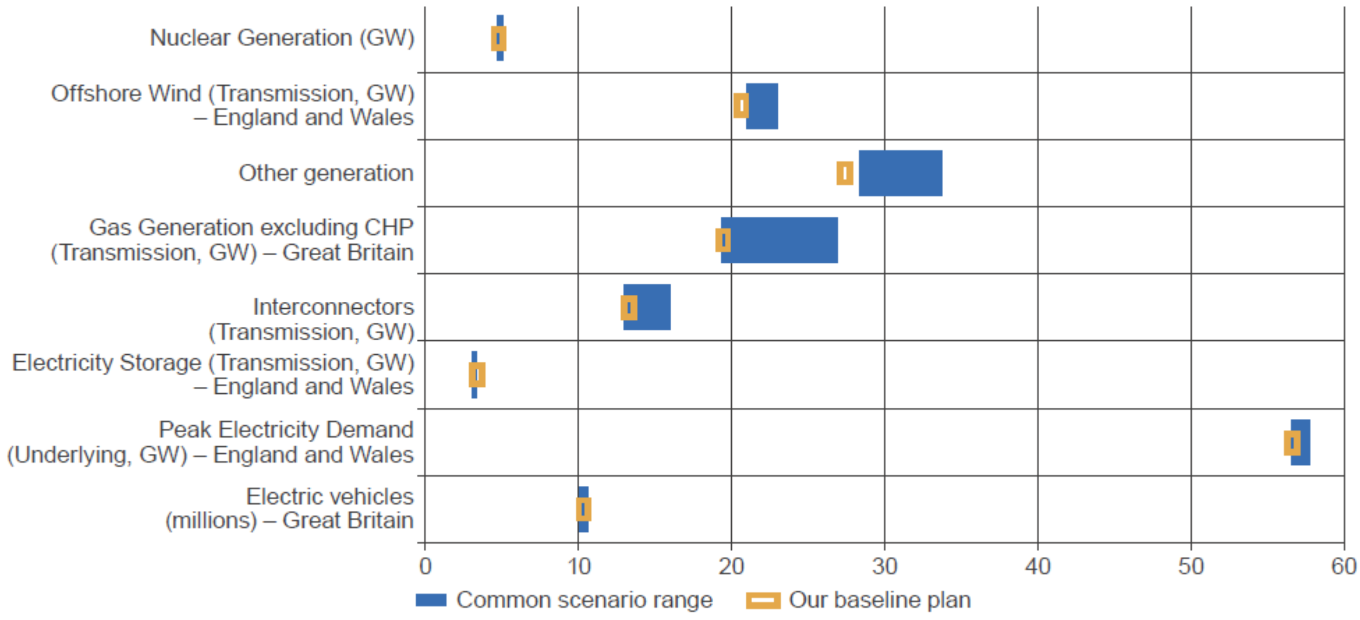

Figure 2: Business Plan scenario compared to Common Energy Scenario (total installed generation, demand, or EVs)

The Common Energy Scenario did not provide a project-specific view of connections. Therefore, to develop a detailed business plan we have utilised project-level intelligence to assess the projects within each technology type that are most likely to proceed. As part of our investment process to avoid incurring transmission costs too early, we routinely assess the viability of our customers' own projects (i.e. the construction a wind farm) to indicate which of these are likely to proceed and those which are more likely to delay / terminate.

While this is not a precise science, a 'customer score' is calculated for each customer project based on several inputs and the investment stage of the project. A low score (1) indicates a customer project is highly unlikely to proceed (in the contracted timescales), while a high score (10) is likely to indicate the customer is well-committed and whose project is likely to be in construction. The 'customer score' provides an indication of the relative likelihood of our customer progressing their projects.

The score is based on quantitative and qualitative inputs. The quantitative inputs include whether projects have secured planning permissions, if a Capacity Mechanism or Contract for Difference contract has been secured, and whether a final investment decision has been taken. The qualitative inputs include a structured assessment of the availability and responsiveness of the customer when we contact them and ask project-specific questions.

It should be noted that a score is a view at a point in time and will change as a customer's project matures. In selecting projects to include in our Business Plan, we have selected customer projects with higher customer scores while also being consistent with the overall plant mix determined set out in the Common Energy Scenario. Figure 3, and the associated table, compares the distribution of customer scores for projects in the T2 Business Plan and those not included.

Despite this approach, we do not have perfect foresight of connections. The actual mix of generation is very likely to be different from that assumed because of the vast range of externalities that affect customer projects; and the selection of a low-end energy scenario, particularly in the context where Government policy is to have net zero carbon emissions by 2050. Our Business Plan therefore contains our latest thinking on how a series of uncertainty mechanisms should be developed, to ensure that allowances reflect the connections that proceed. These are explained in Section 7 of Chapters 7 and 8, and in NGET_ET.12 Uncertainty Mechanism Annex.

Customer Score	In Plan	Not in Plan
Mean	6.3	5.0
Mode	7.0	4.4
Median	6.2	4.5

Figure 3: Customer scores of projects

Table 1 provides the generation projects connecting from 2021/22 with the investment that is required during the T2 period. Some works are shared between multiple projects, or connection phases of the same customer project, in which case the works will be completed for the earlier project or phase (as shown in the table).

Customer Name / Stage	Technology	Year	Size	Excluded Services Expenditure £m)		Local Infra Expenditure (£m)		NDP Stage
			(MW)	RIIO-T2	Total	RIIO-T2	Total	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4.1
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Customer Name / Stage	Technology	Year	Size (MW)	Excluded Services Expenditure £m) RIIO-T2	Excluded Services Expenditure £m) Total	Local Infra Expenditure (£m) RIIO-T2	Local Infra Expenditure (£m) Total	NDP Stage
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Total (Project)			**34,551**	**29.2**	**43.3**	**215.8**	**449.1**	-
Total (T2 outputs)			**15,265**					

Table 1: Projects with spend in the T2 period

The following charts summarise the maturity of the development activities of investments in our Business Plan and the technology types of projects it covers. Figure 4 shows 62% of investment during the T2 period is associated with projects during the early stages of development (Stage 4.0, 4.1, and 4.2) that have estimates based on the Cost Book approach; 17% of investments have had detailed design work completed and a bottom-up cost estimate made but are not yet in delivery; and 21% are already in delivery. It should be noted that investment to provide a customer connection at an early stage of the NDP does not reflect on the viability of the customer's project or whether it will proceed to connection.

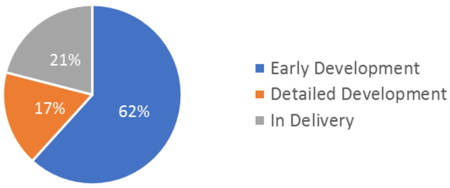


Figure 4 – % of total T2 spend by development stage

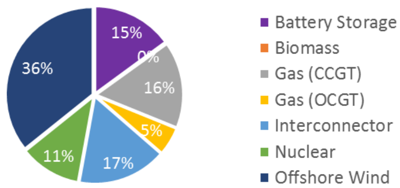


Figure 5 – % of total T2 spend by customer type

Spend during the T2 period is greatest for offshore wind connections, closely followed by investment to connect new interconnectors and new gas-fired power stations (CCGTs), as shown in Figure 5. This is consistent with the total capacity being provided for these technology types.

8. Justification of investment decisions for investments in the T2 period

The following section provides detailed justification of the transmission investment included within the Business Plan (regardless of when the output might be delivered[5]). It covers 99% of the relevant expenditure in the T2 period. The extent of the coverage is shown in Figure 6(a) and Figure 6(b).

Portfolio View

The unit cost (£/MW) of delivering an output for entry capacity has been shown in Figure 6(a) to provide a comparison to the unit cost allowance (UCA) used in the T1 period. The average unit cost of the projects with spend in the T2 period is £[redacted] k/MW (infrastructure costs only). This is lower than the average of projects anticipated to connect during the T1 period (which is £[redacted] k/MW restated in 18/19 prices but ignoring real price effects). Several factors influence the average unit cost of projects within the portfolio but the most significant is the mix of projects that are expected to proceed.

(Note – these charts show projects in the Common Energy Scenario only. To develop accurate uncertainty mechanisms, all contracted generation will be considered. As our analysis progresses, it may indicate capacity (MW) is not the most appropriate cost driver.)

[redacted]

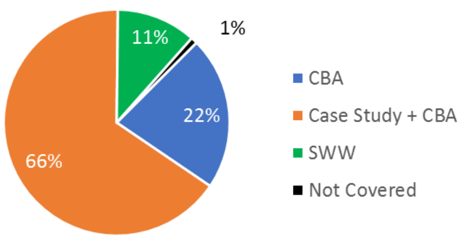


Figure 6(a) (LHS) and 6(b) (RHS) – (a) project costs compared to project size by justification approach; (b) % of spend in the T2 period covered by justification report (Numbers refer to deep dive reference)

[5] Some spend during the T2 period will deliver outputs in T3 or beyond

Case Studies

We have prepared five case studies to complement the 20 CBAs included in this investment justification pack. All transmission costs presented include sole-use and local enabling infrastructure costs. Each customer-driven project is unique because of a range of factors including: their location, size, appetite for a firm[6] connection. Against this background, the case studies have been selected to present in more detail projects which cover a range of investment costs (typically driven by size and location), customer technologies, levels of design maturity, as well as a geographic spread. We have also included examples where the lowest cost transmission solution is not always the most suitable to take forward, when either whole system or consenting issues are taken into account.

Technology Type	Key option selection issue	Example description	Stage
(1) Battery Storage	Managing new technology	<50MW connections	All
(2) Offshore Wind	Whole system / CION	East Anglia Offshore Wind	4.1
(3) CCGT	Cost vs Consenting Risks	King's Lynn B CCGT	4.3
(4) OCGT	Managing delivery risks	Progress Power OCGT	4.4
(5) HVDC Interconnector	Minimum compliant design	Viking Link Interconnector	4.2

Table 2: Projects covered by detailed Case Studies

Basis of selection and preparation of CBAs

We have included a CBA for all projects where spend in the T2 period is forecast to be greater than £2m; or where there is any spend in the T2 period and significant expenditure beyond T2. All CBAs have been prepared using Ofgem's CBA tool.

The costs presented in this section of the justification paper may not align with those presented in the Business Plan Data Tables (BPDTs). This is because option selection will have been undertaken when it was necessary to deliver the investment for the customer. Following this, changes to the preferred option cost could emerge for the following reasons:

- an updated Cost Book becomes available that changes the cost of the investment but leaves the scope unchanged;
- opportunities to 'bundle' separate investments emerge that allow multiple drivers to be met under a single investment (including asset-health related investments); or
- detailed engineering of the preferred option has progressed, which may identify a need for additional scope and / or opportunities for cost savings (which may have equally been relevant for discounted options).

Recognising these risks, we have confirmed that the option we have selected and included in our Business Plan remains the most appropriate option. On average project costs presented in the BPDTs are within ±£2.1m of the preferred option presented in the CBA; and the net cost difference of the total project cost is £27m[7].

[6] A 'firm' connection is a connection that is fully compliant with the design standards and where compensation is provided to generators if they constrained and not able to generate.

[7] If the CBA for East Anglia 6 is removed because it considers two customer phases rather than a single phase (as per the common energy scenario), the average difference reduces to ±£1m and the net total project cost reduces to £8m.

Range of options considered in CBAs

In the case of customer requested connections, the investment option to ‘do nothing’ would not be consistent with our licence obligation to make offers to parties that apply to connect[8]. Ahead of making applications we will have met customers to discuss their requirements and the alternative options. In the case of small generators, this could be a connection to a distribution network; and in the case of DNOs, this could be suitability of low-build solutions such as the installation of an active network management (ANM) scheme.

Sensitivity of CBA to changes in input assumptions

We have investigated the sensitivity of our preferred option to changes to the key input assumptions, including: connection time scales, the cost of carbon and the weighted average cost of capital. Our investigation has focused on projects where the NPV of the chosen option is close to the next alternative option (that meets the customer’s needs). In other cases, where the cost difference to the next cheapest option is greater, the CBA will be less sensitive to cost inputs.

In the case of the generation connections portfolio one project (Dogger Bank 1) was reviewed. The option selected would be unchanged unless costs increased by more than 50% (~£700k) or the alternative option was delayed by more than 15 years. It should be noted that often the cause for cost increases or de lays may apply to alternative and preferred options.

8.1 Small <50MW Connections (Various Stages)

A high volume of new applications has been received for small (<50MW) connections to the transmission system. This size of connection is new to National Grid and our innovative connection design, involving tertiary windings of transformers, has generated a lot of interest from customers that would traditionally connect to distribution networks (DNO) – see Figure 7 (where red sites are committed, and blue sites are available).

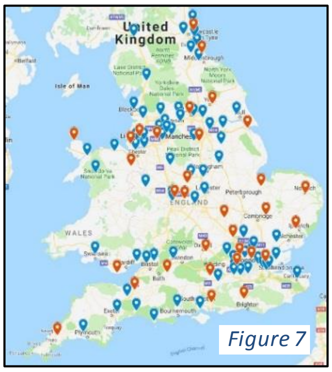


Figure 7

We have received requests from customers developing gas peaking plant and solar farms, but the majority come from battery storage projects. In many cases, these customers will have previously explored connection options with a DNO.

We have considered three options for providing connections to these customers, as summarised below. The lowest transmission cost option has been selected, reflecting the wider benefit customers want to gain from a transmission connection (see below).

Option Selection Summary	
Options Considered (Selected option in bold)	**Cost (£m)**
Option 1: Innovative connection using tertiary windings	[redacted][9]
Option 2: Conventional connection by installing a new SGT	[redacted]
Option 3: DNO provided connection (minimum cost estimate)	[redacted]

[8] See Standard Licence Condition C8

[9] Average of T2 connections

Option 1: Tertiary Windings connection (£[redacted]m) (Selected)

This option provides a connection using the tertiary winding of existing super grid transformers (SGTs). These types of connection typically cost ~£[redacted]m. These customers have applied for offers based on 'customer choice' to allow them to trade-off the reduced cost and quicker delivery timescales against the lower security of the connection.

The tertiary winding of an SGT has a 60MVA rating, which is ideal for these connections. Using these existing assets in an innovative way results in efficiencies by making better use of equipment already on the system. Figure 8 shows how a 13/33kV transformer can be connected into the 13kV tertiary winding of the SGT. A disconnecting circuit breaker (DCB) is a point of isolation so maintenance can be carried out without impacting other customers.

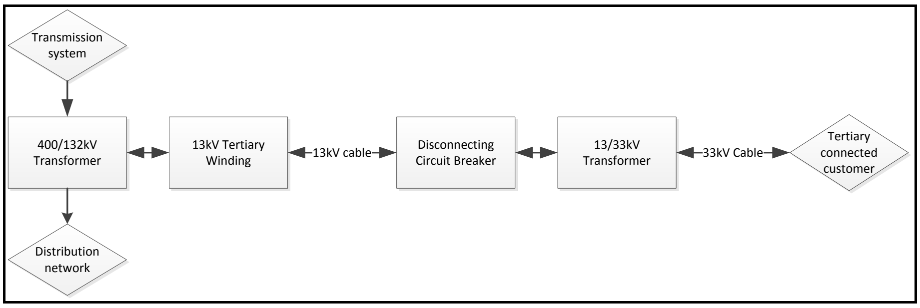


Figure 8: Typical Arrangement for Tertiary Connected Generation

Providing a customer connection in this way means that the SGT no longer serves the needs of a single customer (the DNO). We have therefore proposed changing the charging classification of the SGT, so that it is treated as an infrastructure asset rather than a sole-user connection asset paid for solely by a DNO. All other things being equal, this reduces connection charges revenue, which may reduce the excluded services revenue stream and therefore we would expect this to be corrected in T2 through a true-up mechanism (or a T2 alternative that adjusts automatically within the period).

Option 2 – Conventional transmission connection using a new 400/33kV SGT (£[redacted]m)

The alternative, conventional transmission connection option for these customers would be through a dedicated 150MVA 400/33kV (or 275/33kV) transformer. This option would require the procurement of equipment with a larger footprint, which may require additional land to be purchased at sites where there is insufficient space. Furthermore, these SGTs would far exceed the rating requirements for this type of connection, as well as having a longer timescale for delivery. The costs associated with this option are typically double that of the tertiary connections and was therefore rejected. Nevertheless, variations on this connection design may be considered in the future if there are multiple customers seeking to connect at the same location (or if customers seek increased levels of connection security).

Option 3 – DNO provided connection (£[redacted]m)

Customers of this size have, in the past, nearly exclusively sought connections from DNOs (as this was perceived to be their only option). Based on our discussions with customers considering a distribution connection, we have estimated the minimum cost of a DNO solution (sourced from information provided by DNOs). This cost will increase if the customer is not located close the DNO's substation; and if wider network reinforcements are required deeper within the DNO's network (which we have not been able to assess).

Ultimately, while the cost difference between a distribution or transmission connection can be marginal, customers may choose a transmission connection for reasons other than cost. These can include:

- the customer service received (e.g. support to optimise their project portfolio);
- the ability to deal with a single national counter-party to match their portfolio;
- the timescales of connection; and
- direct (and wider) access to markets (e.g. for ancillary services).

Each of these factors can have consumer benefits by increasing competition and lowering wholesale energy costs.

Responding to customer requirements

The customers' desired lead times for these types of connections is much shorter than traditional transmission-scale generation developments. The preferred connection design outlined above can be deployed at all sites where a suitable SGT exists. To meet the customers' desired timescales, we have adopted a more flexible approach to progressing investments through the NDP, including:

- earlier contractor involvement whilst maintaining contractor competition;
- undertaking some activities in parallel and undertaking earlier governance;
- procurement of a portfolio of works in a single tender event;
- internal procurement of equipment and free-issue for installation;
- in-house design and development of standard protection and control solution; and
- using internal staff for asset inspections and some commissioning activities.

This has resulted in the ability to adapt to customer programme requirements and their changing priorities (e.g. if one site a customer wishes to connect to has planning issues).

Stakeholder and ESO views

The customers who have accepted offers based on a tertiary connection support the proposed design, as it is a cost-effective way for them to connect to the network and they understand the restrictions that will be imposed on them.

The ESO has been extensively engaged during each offer through a range of standing weekly and ad hoc meetings. They support the use of the novel connection design.

Some DNOs have raised concerns about the charging arrangements for sites with tertiary connections that are also currently subject to connection charges[10]. Several bilateral meetings and industry workshops have been held, alongside discussions at the Electricity Networks Association (ENA), to understand and develop a common understanding. As the ESO owns the charging methodology in the Connection and Use of System Code (CUSC), it is taking the lead on this with active support from NGET.

Associated CBAs

We have prepared a single CBA to cover 13 customer connections using a tertiary connection. In each case, the proposed transmission solution and the options available are the same. While individual project costs may vary, none of these would justify an alternative investment option.

Customer Project	CBA Reference
[redacted]	NGET_A8.02_Generation_Connection_CBA13_[redacted].xlsb

[10] The charging issue being discussed is the adjustment made to the DNO's connection charge at the site, and specifically whether only the SGT with a tertiary connected customer should be treated as an infrastructure asset or whether the entire site should be re-classified to be infrastructure.

This CBA covers the following customer connections:

[redacted]

Risks associated with providing tertiary connections

There are a range of risks that are associated with providing tertiary connections. The nature of these will vary from site to site. In the main, these risks are no different from those associated with a modest size capital project, for example, the need to co-ordinate third parties or the risk of buried services. However, we have identified three risks that are unique to this type of connection, these are:

- complications with interfacing into transformer tertiary;
- complications with modifying transformer civils for tertiary connection; and
- complications due to integration with noise enclosures.

Each of these risks has a low likelihood of occurrence (i.e. less than 20%). In the most part, these risks are managed ahead of a customer application by encouraging customers to select sites where a connection has lowest technical risk.

8.2 East Anglia Offshore Wind connection (Stage 4.0 to 4.1)

An area 30km off the coast of East Anglia is an active development zone for offshore wind farms. The development is being led by a partnership called East Anglia Offshore Wind (EAOW). In 2014, EAOW undertook a strategic review of their development plan for the zone. This included a review of project sizes and locations, as well as windfarm technology with the aim of identifying the projects that provided the lowest cost of energy. The review conclusions are reflected in the current contracted connections: East Anglia 1 (680MW); East Anglia 1 North (860MW); East Anglia 2 (860MW); and East Anglia 3 (1200MW).

As these are offshore projects, the transmission investment to connect these are subject to a CION to determine the overall optimum connection. The outcome of this is summarised, focusing on the connection of East Anglia 1 North (EA1N) and East Anglia 2 (EA2).

The option selection concluded that a connection at a new substation at Leiston was the best option when onshore, offshore, and system operation costs were considered across a range of different future energy scenarios. This decision was not the lowest transmission cost option but was the lowest whole system cost. A range of other factors, not least the interaction with nuclear site licence restrictions and land designations of protected area, influenced the final option selection.

Selection of suitable onshore connection points for detailed analysis

The CION assessed a variety of potential onshore locations to connect the windfarms, which included several new or existing National Grid substations. A ‘long list’ of twelve potential sites was initially considered, as summarised below and shown in Figure 9.

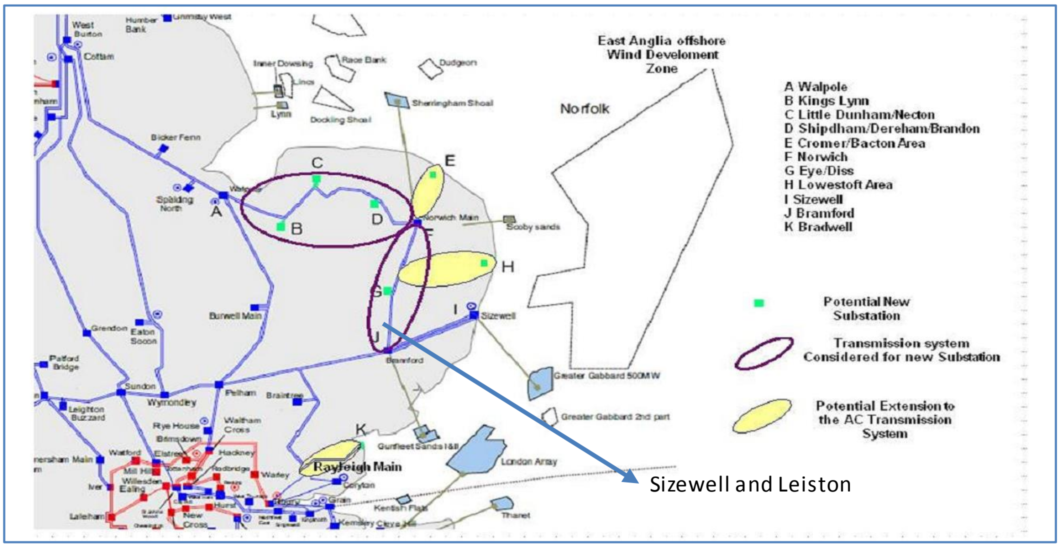


Figure 9: East Anglia Zone Potential Onshore Connection Sites

A. Walpole 400kV substation (Existing)
B. King's Lynn (New)
C. Little Dunham / Necton (New)
D. Dereham / Shipdham / Brandon (New)
E. Cromer / Bacton area (New)
F. Norwich Main 400kV (Existing)

G. Diss / Eye Airfield area (New)
H. Lowestoft area (New)
I. Sizewell 400kV substation (Existing)
I. Leiston 400kV substation (New)[11]
J. Bramford 400kV substation (Existing)
K. Bradwell (New)

The initial options appraisal considered all the sites based on a high-level assessment of programme, construction complexity, land availability, environmental / consenting issues and cost. Locations that were identified to have no benefit over others were parked.

Four connection sites were 'short-listed' and taken forward to detailed options appraisal: Bramford, Sizewell, Leiston and Norwich Main. Due to the interactivity between EA1N and EA2, the CION considered the following combinations of connecting the customer projects:

- Option 1 - Both connecting to Bramford substation
- Option 2 - Both connecting to Sizewell substation
- Option 3 - Both connecting to Leiston substation
- Option 4 - Both connecting to Norwich Main substation
- Option 5 - Split connection between Bramford and Sizewell/Leiston substations
- Option 6 - Split connection between Norwich Main and Sizewell/Leiston substations
- Option 7 - Split connection between Bramford and Norwich Main substations

Detailed CION assessment

During the detailed assessment, the four preferred connection location options were assessed in greater detail by undertaking a desk-based constraint mapping exercise to identify potential substation locations, connection routes and assessing project specific costs (based on a Stage 4.2 cost estimation approach). System studies were undertaken for the various connection option combinations to determine the required

[11] Leiston and Sizewell are electrically the same location.

nationalgrid

scope of works for each. These were then priced to compare Onshore TO costs alongside Offshore TO costs. Table 3 shows the route distance and OFTO cost of the connection sites considered.

Connection Site	Offshore (km)	Onshore (km)	Total (km)	OFTO Cost (£m)
Bramford	58	37	95	[redacted]
Sizewell / Leiston	48	8	56	[redacted]
Norwich	88	37	125	[redacted]

Table 3: Route distance for each short-listed Interface Points and OFTO cost to connect EA Two

The OFTO costs for different connection sites was then combined with the associated National Grid cost, as shown in Table 4, in the least worst regret analysis undertaken by the ESO as part of the CION. Table 4 summarises the outcome of this analysis and compares it against an 'initial ranking' of options that considered factors other than cost.

	Connection Site Combinations	Onshore TO (£m)	Technical Risk	Consent Risk	Initial Ranking (non-financial)	Least Worst Regret (£m)
1	Bramford + Bramford	[redacted]	[redacted]	[redacted]	1	443
2	Leiston + Leiston†	[redacted]	[redacted]	[redacted]	3	0
3	Sizewell + Sizewell†	[redacted]	[redacted]	[redacted]	2	0
4	Norwich Main + Norwich Main	[redacted]	[redacted]	[redacted]	7	1,077
5	Sizewell / Leiston + Bramford	[redacted]	[redacted]	[redacted]	4	317
6	Sizewell / Leiston + Norwich Main	[redacted]	[redacted]	[redacted]	6	409
7	Norwich Main + Bramford	[redacted]	[redacted]	[redacted]	5	702

L – Low; M – Medium; H – High

* Connection into spare bays

†Least worst regret analysis considered Leiston and Sizewell as a single option

Table 4: Summary of Qualitative and Quantitative CION Assessment

Final connection point decision

The CBA concluded that Option 2 or 3 (connecting both EA2 and EA1N to either Sizewell or Leiston substations) was the most economical solution when considering onshore and offshore investment costs and the ESO's system operation costs.

As Sizewell 400kV substation is an indoor gas insulated switchgear (GIS) substation located within the nuclear security perimeter zone, a tri-party meeting between National Grid, EAOW and EdF (the owners of the Sizewell nuclear power stations) was held to discuss the feasibility of connecting EA2 and EA1N at Sizewell. Several complexities were identified with this location, including:

- the requirement to comply with EdF's Nuclear Site Licence requirements;
- manging delivery while Sizewell A was decommissioned;
- ensure no adverse impacts on the operation of Sizewell B and development of Sizewell C (for which extensive commercial indemnities would be required); and
- avoiding additional consenting associated with the close proximity of a site of special scientific interest and an area of outstanding natural beauty (which, based on previous experience with such designations, would be more challenging to secure given the other options available).

Taking all these into considerations, the Sizewell connection was discounted and the option to build a new 400kV substation in the Leiston area (i.e. Option 2) selected.

Connection at Leiston

Once the preferred connection location was determined, a further option assessment was undertaken to determine the optimal connection design at Leiston. Three options were considered. These are covered be the CBA. The lowest cost option was selected: the construction of a new nine bay double busbar substation, tee-ing into the existing circuit between Bramford and Sizewell substations.

Stakeholder and ESO Views

The preferred option has been discussed and agreed by the customer and the ESO during regular update meetings. The ESO has played a central role throughout the CION process to determine the preferred connection location. They are also supportive of the more detailed connection design at Leiston, from commercial and engineering perspectives.

The ESO and NGET have agreed commercial terms for this connection.

Project-specific Risks

As with any significant capital project, there are several risks that need to be managed. These are all detailed in the CBA. The risk with the greatest likelihood (20% - 40% likely) with the most potential to impact the project are the ground conditions that will be encountered. This is not unusual for a project of this type where significant ground works are required to build a new substation. As this project is at an early stage of development, ground surveys have not been undertaken (to avoid the risk of spending too early). However, once these have been completed, detailed design will take place to effectively manage any issues that subsequently arise. As our cost estimate is based on 'typical' ground conditions, the impact on cost will depend on the specific nature of any issue found.

Associated CBAs

The following projects in our Business Plan have or will be subject to a CION assessment. The CBAs presented focus on the local investment based on the optimal connection site.

Customer Project	CBA Reference
[redacted]	NGET_A8.02_Generation_Connection_CBA12_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA19_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA17_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA14_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA03_[redacted]. xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA10_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA06_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA04_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA09_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA11_[redacted].xlsb

8.3 King's Lynn B generation connection (Stage 4.3)

A customer applied for a new 1700MW CCGT generation connection at King's Lynn in Norfolk, East Anglia. Five options were considered during the option selection phase for the associated works at Walpole 400kV substation (as shown in Figure 10), and the lowest cost option that met the customer's needs was chosen.

Option Selection Summary	
Options Considered (Selected option in bold)	**Cost (£m)**
Option 1: Substation extension to the south (cable)	[redacted]
Option 2: Substation extension to the west (cable)	[redacted]
Option 3: Substation extension to the west (GIL)	[redacted]
Option 4: Substation extension to the south (GIL)	[redacted]
Option 5: Do nothing (does not meet driver)	0

The investment to connect this generator includes the construction of a new ~2.5km double circuit 400kV overhead line (OHL), which has an approved DCO, that connects a new King's Lynn 400kV GIS substation to the existing Walpole-Norwich 400kV OHL. A high-level proposed connection layout is shown in Figure 10. In addition to these works, the overhead line connections of the Walpole – Norwich circuit at Walpole 400kV substation needed to be diverted and re-configured. These works, and the associated impact at Walpole 400kV substation, are discussed below.

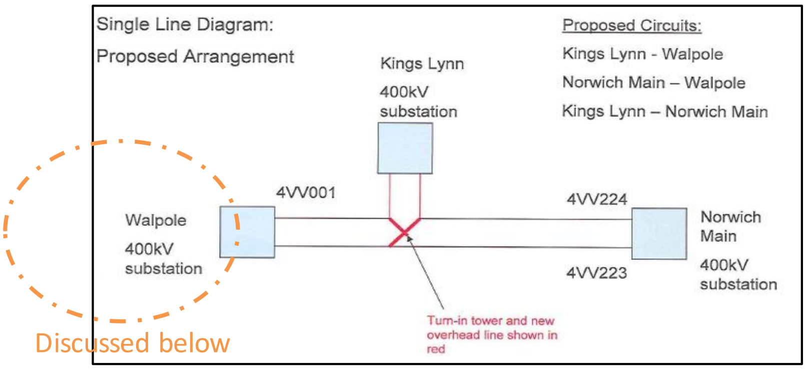


Figure 10: King's Lynn B Connection Layout

One of the key consequences of the additional generation at King's Lynn B, is the potential for power flows at Walpole 400kV substation which are above the rating of the substation busbars. To avoid these excessive power flows, the new King's Lynn to Walpole 400kV OHL circuits must be transposed. Without undertaking this work, the generation at King's Lynn B would need to be constrained off for certain system conditions and the connection design would therefore not meet customer requirements.

Five options were considered during the option selection process to resolve this issue.

Option 1 – Extend Walpole 400kV substation Bus Coupler to South (Cable): ~£[redacted]m

Under this option, Walpole 400kV substation would be extended where the Bus Coupler 2 bay is located, which would then require it to be replaced, as shown in Figure 11. This enables the transfer of the King's Lynn B connection to the other side of the bus section circuit breaker, reducing the flow imbalances at the site. The connection of the overhead line into Walpole 400kV Substation would enter on the same gantry but a cable would be used to transfer the circuit connection onto a different part of the busbars.

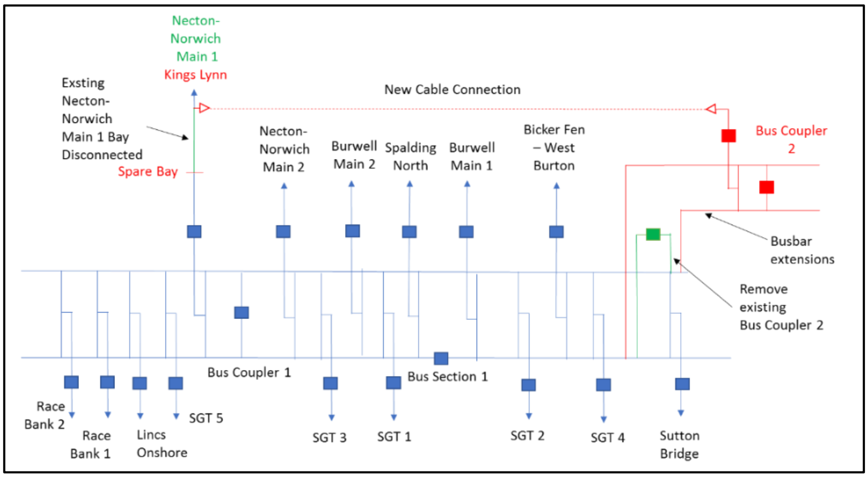


Figure 11: King's Lynn B Connection Layout at Walpole 400kV Substation

Option 2 – Extend Walpole 400kV substation to the West (Cable): ~£[redacted]m

This option was to extend the substation boundary to the west of Walpole 400kV substation. This would then allow a new bay to be installed and a cable provided to connect the new generation bay from where it currently lands at the opposite end of the substation. This option was discounted due to the requirement to remove a DNO tower and relocate (underground) the circuits that are currently using the tower. This added ~£[redacted]m to the project cost and delivery would be critically dependent on the actions of the DNO, which could have a major impact on timescales for completion of the works. This option also required the removal of trees originally planted as part of the screening for the substation which was another undesirable outcome of this option. Therefore, for cost and environmental reasons, this option was discounted.

Option 3 – Extend Walpole 400kV substation to the West (GIL): ~£[redacted]m

This option was to extend the substation boundary to the west of Walpole 400kV substation, as per Option 2, but using Gas Insulated Line (GIL) to connect the new generation from the bay where it currently lands at the opposite end of the substation. As well as being costlier, this option was discounted for the same environmental reasons as Option 2.

Option 4 – Extend Walpole 400kV substation Bus Coupler 2 to South (GIL): ~£[redacted]m

This is the same as Option 1 but using GIL for the cross-site connection rather than cable. This option was discounted as it cost more than Option 1 and offered no other benefits.

Option 5 – Do Nothing at Walpole 400kV substation: £0m

This option would result in excessive power flows requiring generation from the new CCGT to be constrained off. Such a connection arrangement would have required the customer to exercise customer choice and the agreement of the ESO. As neither party agreed the option was discounted.

Stakeholder and ESO views

Stakeholders (the customer, the ESO, and local parties) support the selected option, as it satisfies the need case with minimum spend and has least environmental impact.

The ESO and NGET have agreed commercial terms for this connection.

The customer has separately explored the DNO connections options, but this required: the construction of two new 132kV new OHLs and the re-build of Walpole 132kV substation. The combined cost of this would exceed that of a transmission solution.

Project specific risks

The CBA associated with the works at Walpole 400kV substation covers nine risks. Of these, the most likely risk (40% to 60% likely) with the greatest impact is the discovery of unknown buried services. Detailed engineering design is being undertaken for this project and all reasonable steps have been taken to assess services that might be buried. These include: reviewing the existing records for the site; and undertaking standard land searches.

Associated CBAs

Customer Project	CBA Reference (and Excel filename)
[redacted]	NGET_A8.02_Generation_Connection_CBA05_[redacted].xlsb
	NGET_A8.02_Generation_Connection_CBA20_[redacted].xlsb
	NGET_A8.02_Generation_Connection_CBA01_[redacted].xlsb

8.4 Progress Power 299MW OCGT generation connection (Stage 4.4)

Progress Power signed an agreement to connect a new 299MW Open Cycle Gate Turbine (OCGT) generator at the Eye Airfield Industrial Park. The proposed connection was to the 4YM Overhead Line between Norwich Main and Bramford 400kV substations in East Anglia.

The scope of the works is to construct a new 400kV substation (called Yaxley) near the power station and to provide a connection to the 4YM OHL route. The customer had already secured a DCO for the power station and outline transmission works. The connection location is very rural, and the connection site is in an arable field with no nearby buildings. Against this background, one of the key option selection issues was to reduce the visual amenity impact to comply with the DCO that the customer had secured.

In total, eight options were considered and appraised. The selected option is a compromise between cost, ensuring compliance with industry codes and standards, and complying with consents to manage the visual impact of the connection (Option 5). Since the options available to National Grid had been constrained by the customer's DCO and resulted in a solution that was more expensive than would have been offered without these restrictions (Option 7), we have insisted the customer makes a one-off payment to cover the marginal cost of the selected solution.

Option Selection Summary	
Options Considered (Selected option in bold)	**Cost (£m)**
Option 1: Double busbar GIS with single tee & turn-in	[redacted]
Option 2: Double busbar GIS with single turn in	[redacted]
Option 3: Single busbar GIS with double tee via cable	[redacted]
Option 4: Double busbar GIS with no coupler bay	[redacted]
Option 5: Double busbar GIS with double tee	[redacted]
Option 6: Single busbar AIS with single turn-in	[redacted]
Option 7: Double busbar AIS with double tee	[redacted]
Option 8: OHL Duck-under	[redacted]

This investment is in delivery and the option selection stage was undertaken in 2015 and considered both the substation design and OHL connection. The options considered are listed below (GIS options first, followed by AIS options).

Option 1 - Gas Insulated Switchgear substation (GIS) with single tee and turn in: ~£[redacted]m

The location of the substation was selected to minimise the height of the tower needed to tee into the new substation (by reducing the length of the OHL connection), whilst ensuring the transmission assets would be within the site boundary defined by the DCO. The GIS substation design complied with the DCO requirements but would have required the construction to be undertaken in stages. However, the option was discounted because it did not comply with the negative phase sequence (NPS) limits specified in the Grid Code[12]. The customer was not prepared to have a ‘customer choice’ connection, which would have been needed for this design option, as their assessment of the access restrictions did not outweigh the reduced connection costs.

Option 2 - Gas Insulated Switchgear substation (GIS) with single turn-in: ~£[redacted]m

This option uses a GIS substation (as per option 1) but avoids the requirements for a cable duck-under (and the associated cable sealing end compounds) by utilising a single circuit turn-in to one of the OHL circuits. This option requires less space at the substation and reduces the cost. However, due to the system compliance issues noted above and the restrictions on the customer’s business case which would have required it to agree to a ‘customer choice’ application, this option was discounted.

Option 3 - Single Busbar Gas Insulated Switchgear substation with double tee via a cable: ~£[redacted]m

This option considered a single busbar substation with a double tee connection to the 4YM line via a cable duck-under. This option reduced the cost slightly (compared to the preferred option) since it was a single busbar substation and would have improved visual amenity over a full OHL solution. However, due to non-compliance with the Grid Code outlined in Option 1, as well as the customer not agreeing to a ‘customer choice’ design, it was discounted.

[12] Negative phase sequence (NPS) is a measure of the imbalance between the three phases of electricity supply and can cause overheating of generators and motors connected to the system.

Option 4 - Gas Insulated Switchgear substation with double tee without a coupler bay; ~£[redacted]m

Further cost reduction opportunities (compared to the preferred option) were considered by removing the bus coupler bay, as shown in Figure 12.

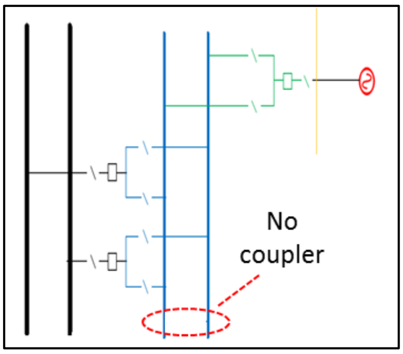


Figure 12: Connection without coupler

In the event of a busbar fault, the bus coupler would have allowed all circuits to be switched to the non-faulted busbar thereby offering better security of supply to the customer. The removal of the bus coupler would affect the security of supply, require the customer to align its outage plans with transmission (reducing its operational flexibility, and is non-compliant with the SQSS).

This option would have again required a customer choice connection, however given the system constraints this design would have cause, both the customer and ESO rejected this option.

Option 5 (Selected) - New double busbar GIS substation with double tee: ~£[redacted]m

The selected solution is the construction of a new double busbar 400kV four bay GIS substation, connected in a double tee configuration into the existing 4YM OHL. The four bays include the customer bay. Figure 13 illustrates the chosen solution.

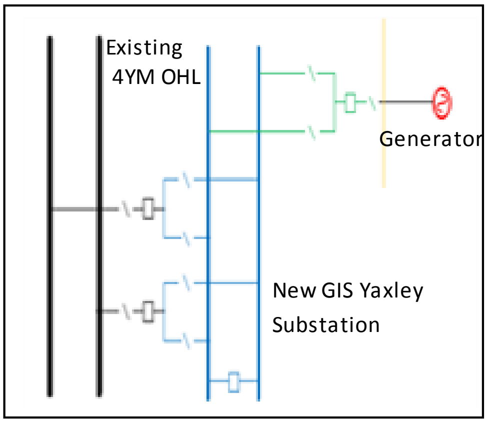


Figure 13: Progress Power Connection and SLD

Working closely with the customer, we held extensive design workshops with the local community. This has allowed us to determine the colour and type of cladding, the pitch of roofs and fence types. This reduced the visual impact as much as reasonably possible.

Every new National Grid substation requires at least two separate optical fibre connections for control and communications. The optical fibre National Grid has on our overhead line routes is used for this. It was initially thought that the existing fibre wrapped earth wire would need to be replaced. However, it was established during detailed design stage that the existing fibre could be successfully unwrapped and reinstated and a standard ground deployment installed between towers. This solution provided two separate fibre routes into the new site and avoided the cost of an earth wire replacement.

Option 6 - Single busbar Air Insulated Switchgear (AIS) substation with single turn-in: ~£[redacted]m

The feasibility of AIS solutions were also considered. AIS substations tend to be cheaper than GIS but also require addition land to achieve the necessary safety clearances. Whilst this solution, which was not SQSS compliant, was deliverable and acceptable to the ESO, the customer was not willing to apply for a 'customer choice' connection, as this removed their entitlement to constraint payments in the event of a failure of the single busbar. This option was presented at the DCO hearings; however, it would not have received consent due to the visual amenity impact of a larger AIS substation. Given these factors, it was decided not to progress this option.

Option 7 - Double busbar Air Insulated Switchgear Substation (AIS) with double tee: ~£[redacted]m

This option is electrically the same as the selected option (Option 5) and uses a double tee connection into the OHL to offer greater security of supply in the event of a fault. While this was the case, due to space constraints and the visual impact (as per Option 6), this option was discounted. However, because this option would have been selected had it not been for the requirements of the customer's DCO, the customer has agreed pay the difference in cost between this option and the selected option. This means no other transmission customers will be affected by this decision.

Option 8: OHL duck-under solution: ~£[redacted]m

An overhead line duck under solution was examined for the connection to the Bramford - Norwich Main circuit, which could have delivered a ~£2m saving (compared to the preferred option) if the OHL route needed to be refurbished at the same time. This option could only be assessed by understanding the condition of the 4YM OHL.

A condition assessment showed there was no condition-based need case to refurbish the OHL. Hence, this option was discounted since the cost-benefit became negligible when there was no condition driver to replace the circuit. Additionally, an OHL duck-under would have made a significant deficit to the visual amenity compared to the cable duck-under. The reduced cost benefit and the planning concerns meant that the option was discounted.

Stakeholder and ESO Views

Local authorities and statutory bodies have been engaged throughout the design process to ensure that the selected design meets the requirements of the DCO. The ESO is supportive as it is SQSS and Grid Code compliant and commercial terms have been agreed.

Project specific risks

Detailed design has been completed and all assessed risks have a low impact on the delivery of this projects (the associated CBA details ten project specific risk), except for a low likelihood risk (less than 20%) that the requirements of the DCO are not met. We believe this risk is low given the extensive engagement that has been had with local stakeholders, and the agreed design complies with the consents provided.

8.5 Viking Link Interconnector (Stage 4.2)

Viking Link is a 1500MW High Voltage Direct Current (HVDC) interconnector, which will electrically connect Denmark to Great Britain. A CION was undertaken to identify the most suitable connection site. Various sites were considered, including: West Burton, Cottam, Bicker Fen, Bramford, Sizewell, Eye, Necton, Norwich Main, Walpole and Spalding North.

The option selection process concluded that a connection at a new substation at Bicker Fenn was the best option when onshore, offshore, and system operation costs were considered across a range of different future energy scenarios. Previous investment decisions ensured that Bicker Fenn substation was readily extendible for future generation connections. This has substantially simplified the connection options and reduced the cost of this project.

During early option assessment, Spalding North and Walpole were ruled out due to the need for significant reinforcement to ensure compliance with the SQSS and avoid additional costs to manage issues associated with national and international designated land protections near Walpole (e.g. longer route lengths to avoid designated areas). Norwich Main was also ruled out as it did not provide additional benefits in comparison to all other options.

A comparative assessment of the remaining sites was undertaken to determine a short-list for establishing the least worst regret investment option. A short-list of three sites was established by considering planning issues, delivery timescales, environment impacts, technical viability of the interconnector cable routes (onshore and offshore), and investment costs. These locations were: West Burton, Cottam and Bicker Fen.

The present value (PV) of capex costs for the interconnector (I/C) developer and TO at these locations are shown in Table 5.

Option	Location	Route Option	PV I/C Capex (£m)	PV TO Capex (£m)	PV Total Capex (£m)	Least Worst Regret (£m)
1	West Burton	North	[redacted]	[redacted]	[redacted]	55
		Direct	[redacted]	[redacted]	[redacted]	24
2	Cottam	North	[redacted]	[redacted]	[redacted]	50
		Direct	[redacted]	[redacted]	[redacted]	17
		South	[redacted]	[redacted]	[redacted]	48
3	Bicker Fen	-	[redacted]	[redacted]	[redacted]	0

Table 5: Comparative option costs and Lease Worst Regret results

Table 5 shows that despite higher TO capex for a connection at Bicker Fen, it is still the most optimal site when the whole system costs are considered. The table also shows Bicker Fen has the least worst regret connection solution for Viking Link, followed by Cottam and West Burton. Given that all sites sit within the same Electricity Ten Year Statement (ETYS)[13] constraint boundary (B8), the ESO's constraint costs were the same for each location.

Design of connection at Bicker Fen

The CION process identified Bicker Fen as the preferred connection site. Work is progressing at Bicker Fen 400kV substation to connect the Triton Knoll windfarm. The Triton Knoll connection converts the existing double teed SGT connection into a full double busbar substation. This work will be completed ahead of Viking Link's connection. As a result, the options to connect Viking Link were limited since space is already available at Bicker Fen to extend it to provide bays for Viking Link; and this is the lowest cost solution.

Stakeholder and ESO Views

All parties, including the customer and ESO, support the chosen connection location and connection decision.

NGET and the ESO have also agreed commercial terms for this connection.

[13] Electricity Ten Year Statement (ETYS) – report published annually and shows the likely future transmission requirements of bulk power transfer capability of the National Electricity Transmission System.

Project specific risks

The CBA for this project has identified five project specific risks. Two risks have a likelihood of 20% to 40% and would have a medium impact on the project. These are:

- the management of third-party interfaces, which is usual in this type of investment, and will be managed through extensive co-ordination and planning meetings; and
- local wildlife concerns (nesting birds) close to the substation that while they are not envisaged to be affected by the works, significant ground levelling will be required. To mitigate this risk, contractors competing for this work will be informed of this risk during the tender phase and be expected to mitigate any impacts.

9. Summary of Cost Benefit Analysis

In total, we have completed 20 CBAs for projects covered by this justification report.

Table 7 below shows the NPV of the preferred option against the other options considered. Where we have not selected the option with the lowest NPV, we have provided a brief description of the justification of our selected option. More details can be found in the corresponding CBA. In some cases, only a single option has been presented, however in each case other options have been considered and the CBA document described why these have been rejected (typically on the grounds of cost).

Table 7 – NPV against options

Project	Baseline	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Comment on selection of preferred option
[redacted]	[redacted]								Lowest NPV solution selected. Alternative options would have incurred additional costs.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Customer to pay the additional cost of selected option, to comply with its DCO.
[redacted]	[redacted]	[redacted]							Lowest NPV solution selected.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					Opt 1 is not viable due as land cannot be purchased & safety clearance issues to properties. Opt 2 is not SQSS compliant.
[redacted]	[redacted]								4 options identified: 2 were discounted during the DCO, and 1 cost significantly more.
[redacted]	[redacted]	[redacted]							Lowest NPV solution selected
[redacted]	[redacted]								3 options identified: 2 rejected due to adverse impact on SSSI and biodiversity. Based on previous projects, these are unlikely to be consentable.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					Lowest NPV solution selected
[redacted]	[redacted]	[redacted]							Lowest NPV solution selected
[redacted]	[redacted]	[redacted]	[redacted]						Lowest NPV solution selected
[redacted]	[redacted]								4 options identified: 2 rejected due to cost and customer issues; 1 was not compliant.
[redacted]	[redacted]	[redacted]							Lowest NPV solution selected

Project	Baseline	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Comment on selection of preferred option
[redacted]	[redacted]	[redacted]							Lowest NPV solution selected
[redacted]	[redacted]	[redacted]	[redacted]						Lowest NPV solution selected
[redacted]	[redacted]								Customer connecting to substation it owns; and NGET solution would have cost more.
[redacted]	[redacted]	[redacted]							Lowest NPV solution selected
[redacted]	[redacted]	[redacted]							Lowest NPV solution selected
[redacted]	[redacted]								3 options identified: both alternatives had increased scope and would cost more.
[redacted]	[redacted]								2 options considered - the rejected option had additional scope and cost more.
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					Lowest NPV solution selected

Key:

Lowest NPV and Preferred Option	**0.0**	**Bold** indicates preferred option
Not lowest NPV and Preferred Option	**0.0**	
Lowest NPV (if not preferred option)	0.0	

The CBAs have been provided in separate Excel spreadsheets, as follows, with the projects in **bold** covered by the detailed case studies.

Customer Project	CBA Reference (and Excel filename)
[redacted]	NGET_A8.02_Generation_Connection_CBA18_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA12_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA19_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA17_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA16_[redacted]xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA14_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA03_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA10_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA15_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA06_[redacted]xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA04_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA13_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA09_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA11_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA02_[redacted].xlsb
[redacted]	NGET_A8.02_Generation_Connection_CBA05_[redacted].xlsb
	NGET_A8.02_Generation_Connection_CBA20_[redacted].xlsb
	NGET_A8.02_Generation_Connection_CBA01__[redacted].xlsb

Customer Project	CBA Reference (and Excel filename)
[redacted]	NGET_A8.02_Generation_Connection_CBA08_[redacted].xlsb
	NGET_A8.02_Generation_Connection_CBA07_[redacted].xlsb

10. Managing Uncertainty

Our plan is consistent with the low end of the common energy scenario and therefore relies on uncertainty mechanisms to deliver for customers and enable net-zero by 2050. We are proposing a suite of mechanisms that allocate risk to whomever is best placed to manage it.

Consumers can best manage uncertainty about the route to net-zero because the route will reflect changes in their behaviour. We are best placed to manage uncertainty over the costs of achieving the outputs consumers want because we can efficiently control our costs.

The volume of generation connections we will ultimately have to deliver in the T2 period is dependent on customer requirements, introducing uncertainty. We have developed a robust unit cost allowance to manage generation connection volume uncertainty in the T2 period. This mechanism will automatically adjust allowances up and down depending on customer requirements, as shown in table 7 below:

Generation Connections – Unit Cost Allowance (UCA) – Volume Driver

Key stats:	No.
Models considered	8
Input data points (projects)	57

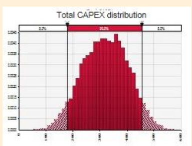
Uncertainty characteristics

i) Risk and ownership

- Customer need and associated type of connection and extent of works are uncertain
- Requirement driven by changing customer activity
- Network company manages cost risk, whilst consumer best to manage volume risk

ii) Materiality

- Estimated range of uncertainty is £277m *(90% of the Monte Carlo simulations guided by the Future Energy Scenarios have a total cost between £178m and £455m)*



T2 CAPEX probability distribution

(output of Monte Carlo analysis)

iii) Frequency and probability

- A minimum frequency of annually
- Near 100% probability of some change in future requirements

T1 experience and learning

i) T1 experience

- Per kW, per circuit-km UCAs – Reducing allowances by >£970m as system needs changed
- Substation cost volume driver UCA is not cost reflective of applications for connections capacity shift towards <100MW
- The overall mechanism has also not been reflective of network upgrades required beyond the connecting substation

ii) Learnings for T2

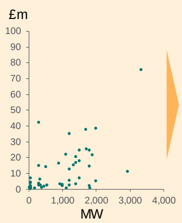
- Mechanism should reflect evolving customer base by accommodating for:
  - smaller connection sizes
  - cost of beyond substation enabling
  - alternative connection solutions, such as tertiary winding connections
- A more cost-reflective UCA designed by rigorous statistical analysis would better protect consumers
- Revenue calculation based on latest forecast of outputs can smooth customer charges

T2 proposals

i) Proposed approach and benefits

- Separate UCA for AIS *vs.* GIS sites, and then further split by new and existing sites and whether the connection is above or below 100MW
- New UCAs are designed using established statistical techniques and stress-tested using Monte Carlo simulations to ensure accuracy and resilient UCA

Inputs (£m vs. MW)



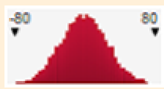
Proposed Design

Substation (sub) Costs – MW connected at:

- new AIS sub: [redacted] **£m/MW**
- existing AIS sub <100MW: [redacted] **£m/MW**
- existing AIS sub >100MW: [redacted] **£m/MW**
- new GIS sub: [redacted] £m/MW
- existing GIS sub <100MW: [redacted] **£m/MW**
- existing GIS sub >100MW: [redacted] **£m/MW**

- Beyond Sub. Circuit Upgrade Costs - [redacted] **£m/circuit km**
- New Overhead Line Circuits - [redacted] **£m/circuit km**
- New Underground Cable Circuits . [redacted] **£m/circuit km**

Testing (cost vs. allowance)



Mean: £0.78m

Std. Dev.: £22.98m

ii) Drawbacks and mitigations

- Additions to the mechanism outweighed by significant increase in cost-reflectivity and mitigated through providing greater clarity on which assets the UCA is covering

Table 7 Proposed uncertainty mechanisms and justification

The detail of our analysis and proposals to manage energy supply and demand uncertainty is set out in annex NGET_ET.12 Uncertainty mechanisms, NGET_ET.12A UM Snapshot table and accompanying workbooks showing the detail of our development and statistical analysis.

11. Conclusions

Our business plan for generation connections over the T2 period is consistent with Ofgem's guidance to base our plan at the low end of the common energy scenario. The individual projects that we have been included have been assessed against a range of factors that indicate the likelihood of customer project progression, and we have included those projects with the highest likelihood of proceeding.

This investment decision pack, comprising a justification paper, five detailed case studies, and 20 individual CBAs, provides robust evidence for the selection of our preferred investment decisions and the associated cost of these. We have considered sensitives of input cost assumptions; and identified key risks and how we plan to mitigate these. In the vast majority of cases, we have selected the option with the lowest net present value. Where this is not the case, we have provided additional supporting evidence for our decision.

The business processes underpinning our investments have been described in detail. This uses externally benchmarked unit costs for cost estimation; has check-points to manage spend and test engineering design decisions; and has opportunities to establish and apply best practice.

There are significant challenges in drawing meaningful conclusions by comparing T1 and T2 costs and volumes. There is no rationale to assume a trend from T1 to T2, as investments and their associated costs are driven by the unique circumstances of the customer projects that are anticipated to connect.