Investment Decision Pack

NGET_A8.03 Demand

December 2019

As a part of the NGET Business Plan Submission

nationalgrid

Justification Paper Load Related – Demand			
Primary Investment Driver	Demand		
Reference	NGET_A8.03 Demand		
Location in Submission Narrative	Chapter 8 – *We will make it easier for you connect and use the network* Section 5.1 ii) *Invest in the network to connect demand customers*		
Cost	£143.1m		
Delivery Year(s)	2021 – 2026		
Reporting Table	B series tables and totex cost-matrix tables		
Outputs in the T2 period	[redacted] super grid transformers		
Spend Apportionment	**T1**	**T2**	**T3**
	£104.5m	£143.1m**	£149.1m

** All costs are in 18/19 prices, unless otherwise stated.*
*** Does not net off capital contributions*

Contents

Executive Summary

Our Business Plan proposes a baseline allowance of £143m to deliver [redacted] new SGTs in T2 (including two new GSPs) to connect new demand customers and to provide additional capacity at existing Distribution Network Owner (DNO) connection sites during the T2 period.

We have robust processes in place to ensure that appropriate investment development is undertaken at the right time; 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 96% of the proposed baseline allowance through: three detailed investment decision case studies; 10 individual cost benefit assessments; and a detailed description of the business as usual, and RIIO-T2 specific, collaborative working with distribution networks.

1. Introduction

NGET's demand customers fall into two categories: direct connections (e.g. large, individual industrial or commercial connections) and Distribution Network Operators.

Direct connections are customers that apply for a connection to the transmission network. These may be industrial customers such as factories, traction connections such as railways (contributing to the decarbonisation of the transport sector), or emerging customers such as data centres. New directly connected customers, that are not yet known, may also come forward during the T2 period which will necessitate the development of appropriate uncertainty mechanisms. Depending on the size of demand required and the type of connection requested by a customer, a new demand connection can range from adding an additional bay at an existing 132kV substation, to constructing a new substation and circuits to connect it to the rest of the transmission system.

Distribution Network Operators (DNOs) differ in that they are customers with an existing connection. Connections between the transmission system and the distribution networks are made at Grid Supply Points (GSPs) and each DNO will have several GSPs. GSPs traditionally only acted to transfer power from the transmission network to the distribution network to supply local demand. However, in recent years the growth of embedded generation has led to periodic operating conditions where DNOs export surplus power onto the transmission network via these GSPs. The capacity of a GSP is generally governed by the number of Super Grid Transformers (SGTs). These SGTs make the connection between the higher voltage transmission network and the lower voltage distribution network. The works required to provide additional capacity for a DNO can range from installing a new 132kV bay at an existing GSP, to constructing an entirely new GSP with circuits to connect it to the rest of the transmission system.

Both directly connected customers and DNO customers must apply to the Electricity System Operator (ESO) for connection to the transmission system (or a modification of an existing connection). For directly connected customers, this will be an entirely new connection; in the case of DNOs, this application is generally to increase the capacity provided at an existing GSP in response to changing demand or embedded generation levels within their local network. Often National Grid and DNOs will have been discussing network issues at the interface point between their networks in joint planning meetings, using information provided annually by the DNO through the formal Week 24 Grid Code data exchange process. These meetings help identify and investigate whole system options. With directly connected customers, their connection application triggers the process to establish the best connection option.

Upon receipt of an application, we assess the effect the customer will have on the transmission network and identify the most economic and efficient solution to facilitate their connection in line with the network design standards set out in the National Electricity Transmission System Security and Quality of Supply Standard

(NETS SQSS). 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 required 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 the T1 period as Excluded Services); or assets beyond the connection charging boundary known as local infrastructure assets (funded in T1 by a baseline allowance and adjusted by the demand-related infrastructure 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 investment not proceeding with their project, we will seek to delay expenditure where possible. This risk is more applicable to direct connection customers than DNOs due to DNO requirements normally being the result of the cumulative effect of many smaller customers connecting to their local network compared to the binary nature of a new single direct connection customer.

2. Demand Connections in RIIO-T1

The baseline for T1 was set using the 2012 Gone Green energy scenario. The scenario anticipated the installation of [redacted] demand SGTs. The following table summarises the baseline and latest view of T1 capacity and spend for generation connections.

	Capacity (# SGTs)	Allowance (£m)	Spend (£m)
RIIO-T1 Baseline / Business Plan	[redacted]	355	650
RIIO-T1 Latest Forecast	[redacted]	167	265

The reduction in forecast connections spend and capacity (based on six years of actuals and 2 years of forecast) has been driven by changes in customer requirements.

While spend has reduced because of these changes, so too have our allowances. Through the operation of the T1 uncertainty mechanisms, demand allowances have reduced by £188m, resulting in spend to be £98m higher than adjusted allowances. There are two main drivers for this:

- changes in customer requirements has resulted in spend being forecast to be £72m higher than allowances, which is a result of the current mix of projects costing more than the unit cost allowance (£[redacted]m/SGT vs £[redacted]m/SGT in 09/10 prices).

- an overspend of £25m has arisen through the need to undertake investment that does not deliver defined outputs (that drive allowances) or that deliver outputs beyond 2022/23 (the so-called RIIO-T1+2 period, eight years of T1 plus the first two years of T2).

It is difficult to systematically determine the efficiencies that have been delivered by load related investments because allowances have been adjustment by an uncertainty mechanism based on an average unit cost. However, we have identified £141m of efficiencies in the demand portfolio, of which £30m relates to projects delivering outputs in T1 and a further £90m relating to active network management (ANM) projects delivering in T1 (avoiding the need for new SGTs). Most of the non-ANM efficiencies relate to changes to the industry codes to avoid unnecessary investment (e.g. increasing the NPS limits in the Grid Code) that will reduce the need for transmission investment in T1 and beyond.

3. Developing and Costing projects

National Grid established the NDP to ensure a consistent approach to project development is applied to all 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. This process is not specific to demand customer connections and is used for all NGET investment projects, however the process described here outlines the steps taken when considering a demand connection.

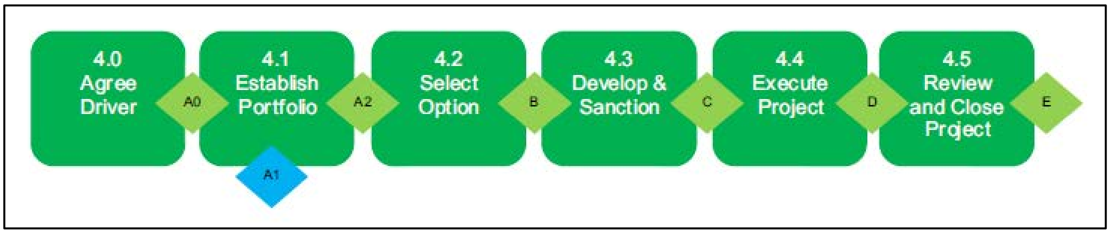


Figure 1: Network Development Process

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 modification application) such that it might be appropriate to return to Stage 4.2 to review the option section.

Stage 4.0 – Confirm and Agree Driver

This stage records the driver for an investment (i.e. a customer application) and the outputs that are expected to be delivered. 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 business 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 asset and the average unit cost to procure and / or install these. The costs provided by the Cost Book are based on delivered costs 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 (typically when a connection offer is signed), the project shall be presented to Gate A2 and, if successful, move into Stage 4.2.

Stage 4.2 – Option Selection

The purpose of this stage is to identify a full set of options that satisfy the driver 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.

The options are then appraised to identify a preferred option. Options are costed using the Cost Book. When decisions are finely balanced, a more detailed cost benefit analysis 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, if an investment impact sites of special scientific interest, areas of outstanding natural beauty, or endangered species).

Once a preferred option is selected and it is appropriate to commit to greater resources to develop and sanction the preferred option, the project shall be presented to Gate B and, if successful, move into Stage 4.3.

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 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 is stage 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 includes tendering and contract award, 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 complete, all financial matters settled (e.g. contract claims), lesson learnt captured and consolidated, and systems updated (e.g. to ensure correct maintenance occurs), 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 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 decision making 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. 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, the calculation is: number of assets required x unit cost of asset). The unit cost 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 cost unit 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 detailed design (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. In some cases, a checklist might be used, to provide a consistent approach and ensuring that engineering decisions that have been made in the past are fed into the design of all similar schemes in the future.

6. Development assumptions and risks

Assumptions are made for investments as they progress through the NDP. These are inherent in a process that increases our understanding of the scope as investments progress through successive development stages. The key assumption during the early stages of development (typically Stages 4.0 to 4.2) is that the project will have a typical scope which is costed using the Cost Book. However, as the project development process 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 a later stage, say Stage 4.3, for a customer that is now delayed. The same investment may, however, be of use for another customer 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 development costs may have already been incurred. To mitigate this risk, customers make financial commitment to transmission investment (through the ESO), which encourages them to make applications to delay their connection date before significant transmission costs are incurred.

- 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 and has developed good relationships with landowners and consenting authorities, so that these 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 then 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).

Each project has its own specific risks. Therefore, for each project in this investment decision pack that has a detailed cost-benefit analysis, a project-specific assessment is included.

7. Demand Background for our Business Plan

The assumptions regarding customer activity that inform our Business Plan come from several sources: our existing portfolio of contracted direct connection customers; the common energy scenario; external stakeholder engagement with DNOs; and the formal data submissions and local forecasts provided by DNOs.

Common Energy Scenario

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.

Demand in England and Wales is likely to see change over the T2 period, driven by digitalisation, decarbonisation, and decentralisation. We expect the number of electric vehicles to continue to grow over the period, but this will have a minimal impact of peak demand, as we do not expect charging to occur at these times. The scenario assumes very little change in demand due to the electrification of heat. Therefore, the level of demand on the transmission system is likely to fall, as embedded generation continues to connect[1].

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. We have also assumed 47GW of installed embedded generation at 2030. This 2GW more than the Common Energy Scenario, as this results in a low-end view of demand on transmission system.

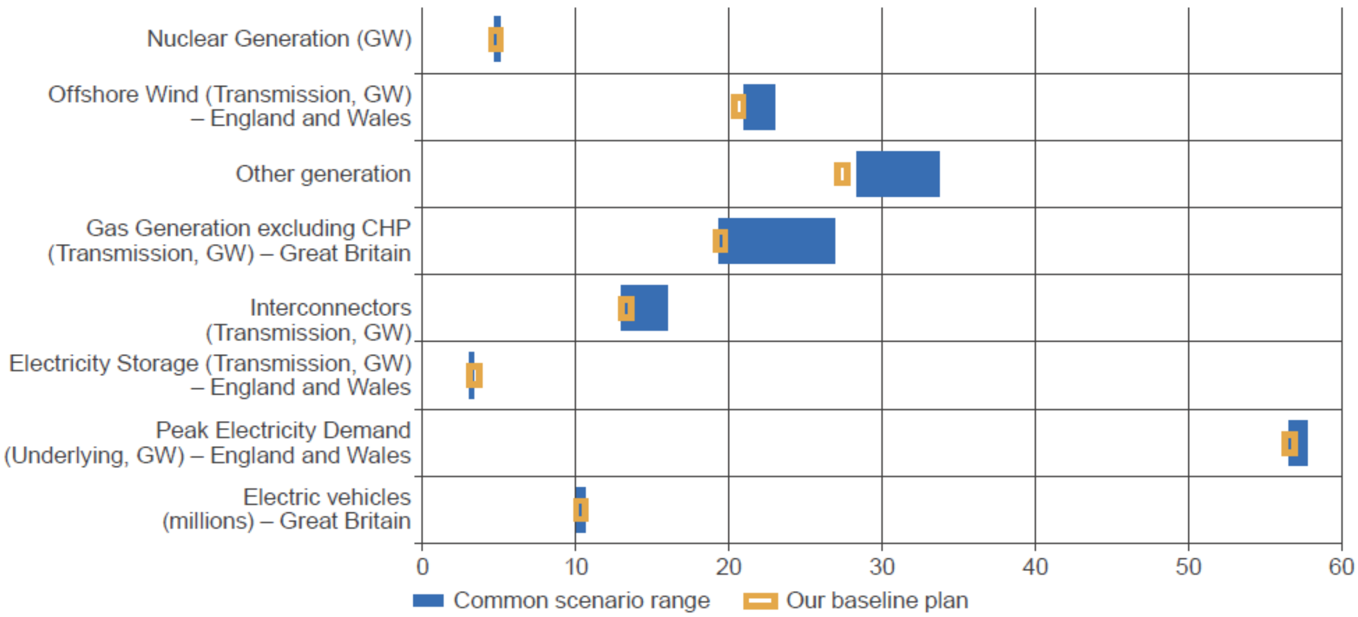


Figure 2: Business Plan scenario compared to 2030 Common Energy Scenario (total installed generation, demand, EVs)

Based on this scenario, we will invest to meet a variety of different customers' needs at various locations across the T2 period. The following map (Figure 3) shows the location of the key investments in our Business Plan, alongside the customer-type.

[1] The growth of embedded generation can cause fault level issues, which will drive investment to ensure assets operate safely under fault conditions. We propose this investment is funded through an uncertainty mechanism.

[redacted]

Figure 3: Map of customer connections during the T2 period

New directly connected customer connections

We have a portfolio of direct connection customers with a contracted agreement to connect in the T2 period, or by a date that requires spending during T2. It is likely that some of these customers will either change their plans (usually in the form of a delay to their requested connection date) or cancel their projects. Therefore, to ensure our business plan is credible, we have taken a view as to which customers are likely to progress and when they will actually connect. This view has been informed by a range of factors, including the (financial and business) commitment made by the customer and the responsiveness of the customer to project queries.

Table 1 provides the details of the direct connection customer projects we have included in our baseline plan and the investment that is required during the T2 period. Projects where the output is delivered in either the T1 or T3 periods, but spend occurs in T2, are highlighted and these outputs are not counted in the total output volumes for T2.

Total spending in the T2 period is £[redacted]m, delivering [redacted] new SGTs (although most of the spend associated with this will have been incurred during T1). Spend will commence in T2 for [redacted] new SGTs at [redacted] new GSPs ([redacted] SGTs at each site) to connect HS2[2]. The timing of this is uncertain given the Government's ongoing review of this project. Against this background, should the project proceed more quickly than we have anticipated, our proposed uncertainty mechanisms would increase allowances in the T2 period, to allow this work to be delivered in timescales acceptable to the customer.

[2] A third site **(XXX)**is also required for the HS2 project ([redacted] SGTs at a new GSP) but following its delay, there is no spend in the T2 period and so it has been excluded from Table 1.

Site	New GSP	No SGTs	Year	Sole User (£m)		Infrastructure (£m)		Total (£m)		NDP
				T2	Total	T2	Total	T2	Total	
[redacted]	No	[redacted]	20/21	[redacted]	[redacted]	[redacted]	[redacted]	1.0	15.1	4.3
[redacted]	No	[redacted]	21/22	Included in the above investment						
[redacted]	Yes	[redacted]	28/29	[redacted]	[redacted]	[redacted]	[redacted]	2.2	42.6	4.0
[redacted]	Yes	[redacted]	29/30	[redacted]	[redacted]	[redacted]	[redacted]	0.2	27.9	4.0
Total T2 Outputs		[redacted]								
Total Spend				[redacted]	[redacted]	[redacted]	[redacted]	**3.3**	**85.6**	

Table 1: Direct connection customer projects with spend in the T2 period

(Note, compared to the July and October draft submissions, we have substantially delayed the connection of the HS2 due the uncertainty caused by the review the Government is currently undertaking. This submission assumes the earliest connections will be 28/29. However, should the project proceed more quickly than assumed, we would expect the demand uncertainty mechanism to increase our allowance. For completeness, we have retained the case studies and CBAs to justify the HS2 connections we envisage.)

DNO customer connections

Ensuring that there is sufficient capacity at GSPs to continue providing a secure energy supply to consumers, whilst also facilitating embedded generation growth, is a key whole system objective for the T2 period and beyond.

In preparing our T2 plan we engaged directly with the 12 England and Wales DNOs to discuss their future requirements. This is over and above the existing planning and network development processes that takes, which include:

- at least two joint technical planning meetings (JTMPs) a year where transmission – distribution interface issues are discussed, including asset management issues and concerns;
- regular calls with the DNOs (and NGESO) to discuss more urgent issues / live offers and applications, many of which happen twice a month; and
- annual data exchanges that trigger a suite of analysis to check compliance with planning standards (where issues are identified, these will be discussed bilaterally to establish the most appropriate remedy).

By providing the correct levels of capacity at distribution / transmission interface points, NGET can help the GB electricity market maximise the use of decentralised renewable energy resources whilst keeping costs as low as possible for consumers. Failure to deliver appropriate reinforcements in a timely manner could result in delays in connecting new decarbonised and decentralised generation customers. It could also cause restricted operation which would limit the economic and environmental benefits.

Due to the specific and technical nature of the required discussions, we have undertaken a series of bilateral workshops with each individual DNO organisation to establish the investment included in our T2 baseline. A two-phase approach was taken to allow initial plans and assumptions to be discussed and feedback obtained. This engagement was designed to build a stakeholder led plan and consider whole system options. The two-phase approach allowed us to work through initial assumptions and proposals with DNOs and use their ideas and feedback to inform our Business Plan.

Each proposed investment was discussed with the relevant DNO to challenge and review the need case, proposed delivery timing, and explore whole system alternatives. As part of these discussions we sought to test the need case for these investments by challenging the assumptions made in the DNO's data submissions (e.g. the assumed output of embedded generation at time of peak demand) and investigating if any non-build, whole system solutions could be made available. Non-build solutions, in the form of network reconfiguration or the use of Active Network Management (ANM) schemes to control customers connected to the DNO networks, were identified at some GSPs allowing transmission investments to be removed from our plan.

In line with our aim to create a business plan that delivers for our customers, we also worked with DNOs to assess any local scenario forecasts they may have developed or any specific customer activity they may be aware of that is not yet captured in the formal data sources (e.g. a significant customer that may have contacted a DNO about a potential connection but has not yet formally applied). This process is explained fully in NGET_A7-8.03 Whole Systems annex.

The investments proposed in our baseline plan represent the sites where both we and the DNO have come to agreement that no alternative solution is available, and a new transmission investment represents the most economic and efficient option for consumers in meeting the DNOs' requirements and maintaining the security of the network.

The following table shows the investments identified through our DNO engagement sessions. Projects where the output is delivered in either the T1 or T3 periods, but spend occurs in T2, are highlighted in yellow and these outputs are not counted in the total output volumes for T2.

Total spending in the T2 period is £140m delivering an output of [redacted] new SGTs (£28m is related to projects that will deliver outputs in T1 or T3). [redacted] of the SGTs in T2 will be located at a new GSP with the remaining SGTs being delivered at existing substations.

Site	New GSP	No SGTs	Year	Sole User (£m)		Infrastructure (£m)		Total (£m)		NDP
				T2	Total	T2	Total	T2	Total	
North Hyde	No	-	20/21	[redacted]	[redacted]	[redacted]	[redacted]	0.1	0.1	4.2
Bengeworth Road	Yes	[redacted]	27/28	[redacted]	[redacted]	[redacted]	[redacted]	9.0	36.2	4.0
Berkswell	No	[redacted]	22/23	[redacted]	[redacted]	[redacted]	[redacted]	14.9	15.5	4.0
Bramford	Yes	-	22/23	[redacted]	[redacted]	[redacted]	[redacted]	1.3	24.0	4.4
Bridgwater	No	[redacted]	24/25	[redacted]	[redacted]	[redacted]	[redacted]	16.4	17.9	4.3
Harker	No	[redacted]	23/24	[redacted]	[redacted]	[redacted]	[redacted]	18.2	19.4	4.2
Fawley	No	[redacted]	22/23	[redacted]	[redacted]	[redacted]	[redacted]	11.5	11.9	4.0
Lister Drive	No	-	22/23	[redacted]	[redacted]	[redacted]	[redacted]	2.7	2.9	4.0
Little Horsted	Yes	[redacted]	23/24	[redacted]	[redacted]	[redacted]	[redacted]	33.4	36.8	4.2
Oldbury	No	[redacted]	22/23	[redacted]	[redacted]	[redacted]	[redacted]	11.9	12.4	4.0
Taunton	No	[redacted]	23/24	[redacted]	[redacted]	[redacted]	[redacted]	2.0	9.5	4.4
Twinstead	Yes	[redacted]	26/27	[redacted]	[redacted]	[redacted]	[redacted]	18.2	36.2	4.0
West Burton	No	[redacted]	20/21	[redacted]	[redacted]	[redacted]	[redacted]	0.3	12.8	4.3
Other (<£50k spend in T2)				[redacted]	[redacted]	[redacted]	[redacted]	0.0	83.0	-
Total T2 Outputs		[redacted]								
Total Spend				[redacted]	[redacted]	[redacted]	[redacted]	**139.8**	**318.7**	

Table 2: DNO customer projects with spend in the T2 period

In two cases - Lister Drive and Bramford - the table shows there is investment in T2 (£[redacted]M) without the delivery of any additional SGTs. In the case of Lister Drive, the work is to facilitate SP Manweb's work to replace its 132kV substation. In the case of Bramford, the work is to complete the transfer of [redacted] SGTs from the old air-insulated substation to the new gas-insulated substation.

Combined portfolio (direct customers and DNO customers)

The following charts summarise the maturity of the development activities for all the demand investments in our Business Plan and the proportion of investment for each customer type.

Figure 2 shows 86% of investment by spend during the T2 period is associated with projects in the early stages of development (Stage 4.0, 4.1, and 4.2) that have estimates based on the Cost Book; 12% of investments have had detailed design work completed and a bottom-up cost estimate made but are not yet in delivery; and 2% are already in delivery.

It should be noted that investment being in the early stage of the NDP does not necessarily reflect on the viability of the customer's project or whether it will proceed to connection. The decision of when to commence further project development (and hence commit spend) is based on the time required to develop and deliver the investment in line with a customer's requested connection date. A project being in the early stage of the NDP may simply indicate that a connection date is far enough in the future that it is not yet necessary (nor economic and efficient) to begin further development.

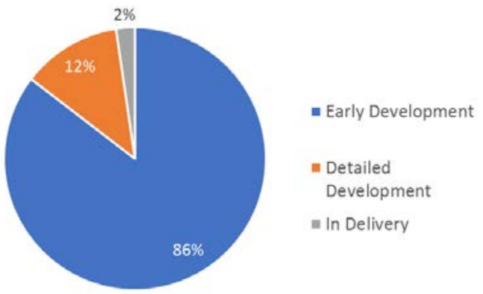


Figure 2 – % of total T2 spend by development stage

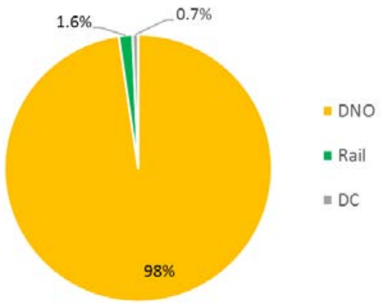


Figure 3 – % of total T2 spend by customer type

Figure 3 shows that the vast majority of spend during the T2 period is for DNO customers (98%). Data Centre connections (a type of directly connected customer) currently make up less than 1% of our plan. However, given the current levels of pre-application discussions, we expect more customers of this type to submit connection applications as we move into the T2 period. Accordingly, given this expectation, an appropriate uncertainty mechanism is needed to cater for these circumstances, to ensure allowances reflect the change in future connections.

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

The following section provides detailed justification of the transmission investments included in our Business Plan. It covers 96% of the relevant expenditure in the T2 period.

Portfolio View

Figure 4 shows the distribution of the total costs across the projects included in our business plan. It combines the costs of the assets directly charged to the connecting customer (connection assets), and the infrastructure assets that are funded through the main price control, adjusted by the associated uncertainty mechanisms, and recovered through the ESO's infrastructure charges.

[redacted]

Figure 4: Cost distribution of demand projects with outputs in the T2 period

Projects that involve the construction of a new GSP substation can be significantly more expensive than schemes that involve the addition of new SGTs at existing sites. No specific output was defined in T1 for delivery of new GSPs. It is therefore proposed that the uncertainty mechanism used in T1 to cover demand connections is expanded to account for this difference in cost between projects requiring a new GSP and those that involve adding SGTs to existing sites. This is described in Chapter 8, Section 7 and in annex NGET_ET.12 Uncertainty mechanisms.

The cost of delivering SGTs at an existing site range between £[redacted]m and £[redacted]m. Costs vary according to the number of SGTs and the specific conditions and restrictions at each site.

Selection of projects for Case Studies and CBAs

We have prepared three case studies to show a variety of investment drivers; a range of investment costs; and typical investment decisions. These projects are briefly described in the following table and Figure 5 shows the projects covered by this investment decision pack: projects with case studies and CBAs are shown with an amber star; and all projects with more than £2m spend in the T2 period have had a CBA prepared.

Two of the projects where that we have prepared case studies illustrate the whole system options that have been considered as part of the joint planning and development work undertaken by National Grid and the relevant DNO. In both these cases, both network companies have agreed a transmission solution best meets the DNO's needs and the solution are in consumers' interest.

Investment Type	Key option selection issue	Example description	Stage
(1) Rail Connections	Power Quality management	HS2 traction supplies	4.0
(2) New GSP	Whole system consideration	Little Horsted	4.2
(3) Additional SGT	Whole system consideration	Fawley SGT	4.0

[redacted]

Figure 5 - Demand Investment Portfolio

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 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 (this could include 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. Typically project costs presented in the BPDTs are within ±£4m of the preferred option presented in the CBA; and the net cost difference is £24m from a total project cost perspective.

To a large extent, the difference is an artefact of how the CBA was prepared for Bengeworth Road. Specifically, the project cost used in the CBA includes a further phase of works at this site, which was considered to optimise the overall timing of the investment. If this investment is excluded, the average net project cost difference between CBAs and the BPDTs reduces to ±£1.5m for the preferred option; and the total difference of the total project cost reduces to £[redacted]m.

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[3]. Often ahead of

[3] See Standard Licence Condition C8

making applications we will have met customers to discuss their requirements and the alternative options that might be available to them. In the case of small demand loads, 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 CBAs to changes in input assumptions

We have investigated the sensitivity of our preferred option to a number of changes to the key input assumptions, including: the cost of carbon and the weighted average cost of capital. We have focused on five projects where the difference between the NPV of the preferred option was close to the NPV of the next lowest cost option. Specifically:

- in the case of the (delayed) HS2 connections, the customer has rejected cheaper compliant options and opted for an alternative solution, which it has agreed to pay the cost differential between the lowest cost option and the selected (this is discussed further in the case studies);
- the preferred options are insensitive to changes in carbon prices or the weighted average cost of capital used; and
- in one case, a small change (~£10k) in the cost of the preferred option may make an alternative option more cost effective (but only to a small amount).

It should be noted that often the cause for cost increases (or decrease) may equally apply to alternative and preferred options.

8.1. HS2 Phase 1 Portfolio – Quainton Traction Supply Point

The construction of a new high-speed rail link between London and Birmingham has triggered the requirement for several transmission investments. Some of these projects are required to divert existing infrastructure to enable the rail line to be constructed, while other projects will provide power supplies to the proposed rail infrastructure.

NGET and HS2 are working closely to identify and develop all connections required to facilitate the construction and operation of this key piece of national infrastructure. Early feasibility stage coordination with HS2 ensured that all the required connections to the transmission system were designed to a level where the land proposals could be fed into a hybrid Bill[4], prior to submission to Parliament and later, for Royal Assent.

These connections are complex, spanning several technical and planning issues, such as: power quality and resilience, interaction with existing National Grid and third-party infrastructure, land requirements, circuit routing and environmental risks and constraints.

One technical issue that had to be overcome arose from the power quality conditions associated with rail connections. The transmission system is a 3-phase system, with voltage and currents balanced across the phases because most connections to the transmission system are 3-phase connections. However, most rail supplies are provided as single-phase connections, leading to imbalances known as Negative Phase Sequence (NPS) voltages.

[4] A hybrid Bill is a set of proposals for introducing laws or changing existing ones. They are generally used to secure powers to construct and operate major infrastructure projects of national importance.

Power system studies carried out for the HS2 Phase 1 connection at Quainton demonstrated that the use of standard single-phase traction supply transformers would, under certain outage conditions, result in NPS voltages outside the limits in the Grid Code. Therefore, the options being considered, and designs taken forward had to take account of this issue.

Working with HS2

We have worked collaboratively with HS2, often based out of their offices in Birmingham, to ensure we develop an effective solution and understand the interactions between transmission investment options and the consequences on HS2's cost.

Selection of preferred option

As there is no existing substation infrastructure in the immediate vicinity of Quainton, this connection would require the design and construction of a new substation and turning nearby overhead line circuits into the substation to connect it to the transmission system. Three options were considered to meet the customer's requirements.

£m	National Grid Costs	Additional HS2 Cost	Total Cost
Option 1	[redacted]	-	[redacted]
Option 2 (Preferred)	[redacted]	[redacted]	[redacted]
Option 3	[redacted]	[redacted]	[redacted]

Table # - Options considered for HS2 Quainton connection

Option 1 – Single Tee and Single Switch Mesh ~ £[redacted]m

The most cost effective, compliant solution was deemed to be a 3-circuit design; in this case the turn-in of the Cowley – Sundon 400kV circuit onto a single-switch mesh, and a single tee-in of the Cowley – East Claydon 400kV circuit (similar in configuration to Figure 6 above). However, NPS restrictions would exist with this design, even with the use of 3-phase 180MVA 275/66kV traction supply transformers.

This is due to the mesh design, which is prone to NPS issues under certain conditions. HS2 rejected this option in favour of a higher level of connection security (Option 2). As this design is more than the minimum compliant solution, HS2 will pay the additional cost.

Option 2 – Double Busbar Substation with Double Circuit Turn-in ~ £[redacted]m

This solution requires the turn-in of both circuits into a new double busbar substation, rather than a single turn-in and single tee. This design delivers an efficiency through the use of existing tension towers that were previously installed for HS2 OHL diversion work.

[redacted]

Figure 8 Quainton Double Busbar Solution

Option 3 - Double Busbar with Balancing equipment ~ £[redacted]m

This option is identical to Option 2, with the addition of the installation of phase balancing equipment at the 400kV substation to mitigate any residual NPS restrictions. This additional equipment is estimated to increase the overall project cost by around £[redacted]m.

HS2 had to balance the additional cost of the phase balancer against the residual operational restrictions it would face with it. HS2 chose to accept the additional level of risk associated with Option 2 (the selected option), to avoid the cost of the phase balancer.

Risks associated with the selection option

The risk with the greatest likelihood (60% to 80% likely) is the availability of outages or the late cancellation of outages. This is expected to have a very low impact on the project given most of the work will be undertaken offline and the ESO will not have firm outage plans (given the potential date of connection). National Grid works closely with the ESO to develop outage plans and priority is given to customer-driven investments. There are no high-impact risks, and all those that have been classified as a having a medium-impact are standard risks that would be expected at this stage of project development.

Stakeholder and ESO views

The proposed design takes account of HS2's desire to minimise impact on local communities by avoiding the construction of additional towers.

NG ESO have been regularly engaged, to manage contractual changes with HS2 and to mitigate Negative Phase Sequence problems. Both parties are satisfied with the agreed upon design. NGET and the ESO have agreed commercial terms.

Associated CBAs

The following CBAs are associated with rail connections.

Site	CBA Reference
[redacted]	NGET_A8.03_Demand_CBA04_[redacted].xlsb
[redacted]	NGET_A8.03_Demand_CBA03_[redacted].xlsb
[redacted][5]	NGET_A8.03_Demand_CBA07_[redacted].xlsb

8.2. Demand driven new GSP example - Little Horsted (Whole System consideration)

The investment is required following a connection application in 2016 by UKPN for the connection of a new GSP consisting of [redacted] 400/132kV 240MVA SGTs at Little Horsted. UKPN requested this connection as they are due to demolish their existing 132kV PO overhead line route connecting Eastbourne and Lewes. The main driver of the scheme is to maintain security of supply to the Lewes/Newhaven demand group, while addressing deteriorating asset condition and wayleave terminations along several sections of the route.

We are informed by UKPN that their PO route is suffering from severe asset health issues, with foundations, steelwork and fittings in need of repair or replacement, due primarily to the proximity to the south coast and the resultant salt pollution. In addition, several landowners have terminated their wayleave agreements for this route. UKPN believe that, as this route traverses part of the South Downs National Park, negotiating new agreements and obtaining planning permission would take several years.

[redacted]

Figure 9 Diagram of the Lewes/Newhaven UKPN Demand Group

Option 1 – Cable the existing 132kV PO OHL – Southern Cross to Lewes ~ £[redacted]m

To ensure the appropriate whole system solution, options to replace the existing PO 132kV overhead line route with underground cables, within the UKPN network were explored. This option involves a cable circuit from the Southern Cross compound to Lewes, which would be routed through the town of Portslade, Brighton. This would involve crossing numerous road junctions as well as accesses to homes and business parks. The alternative route for this option is to divert around the A27, which is the main A-road between

[5] No spend for Ickenham is expected during T2. However, as the timing of this project is uncertain given the Government's review of HS2, we have included the CBA for this investment for completeness.

Brighton and Eastbourne, however, this proposal would be costly and likely encounter many of the same difficulties.

Option 2 – Cable the existing 132kV PO OHL – Pevensey to Lewes ~ £[redacted]m

An alternative cable option within the DNO network would be a cable route from Pevensey to Lewes, routed through rural areas and eventually the town of Hailsham. The route from Pevensey would involve large sections of road excavation which, due to the narrow verges along these stretches of road would require significant traffic management on the main roads in and around Hailsham.

Option 3 – (Preferred Option) Construct a new GSP at Little Horsted ~ £[redacted]m

This option involves the construction of a new Grid Supply Point (GSP) at Little Horsted, which would connect into the existing Bolney – Ninfield 4VM 400kV OHL route. The new substation design that has been proposed would be a single switch mesh connecting [redacted] 240MVA 400/132kV transformers. A new terminal tower will need to be constructed to facilitate the turn-in of the Bolney – Ninfield 1 400kV Overhead line circuit. This option is a combined investment as UKPN will install cable circuits from the new GSP to their Lewes substation. The costs for these works have been included in the total costs of this option.

The decision to progress with this option was taken in 2017 when the optioneering exercise was undertaken and at this stage was the lowest cost option once UKPN's and NGET's costs were combined. Since this point, the project has progressed and developed further. As a result, the estimate for the NGET element of the works has increased as the scope of the project has become better defined. The costs for the alternative options have not been revisited for the purposes of this report. It is our expectation however that if the alternative options were investigated in further detail, the estimated cost to complete them will be higher than first proposed by UKPN.

This option addresses numerous issues for UKPN. This solution will:

- avoid replacement of the PO route, mitigating long standing grantor issues;
- remove an OHL from an area of outstanding natural beauty (AONB);
- maintain P2/6 compliance for this demand group;
- mitigate the need to install long cable circuits and associated infrastructure, which cause significant disruption during construction on road networks and have high environmental and ecological impacts;
- provide a cost-effective way of delivering future capacity reinforcement (which UKPN has been actively discussing with NGET and could not be cost-effectively accommodated by the alternative options).

£m	**UKPN Cost**	**NG Cost**	**Total Cost**
Option 1	[redacted]	-	[redacted]
Option 2	[redacted]	-	[redacted]
Option 3 (Preferred)	[redacted]	[redacted]	[redacted]

Table 4 Little Horsted Options summary (£m)

Given the driver of this investment, we have reached a commercial agreement with UKPN to ensure that any costs for this investment beyond those that we have price control funding, will be recovered from UKPN.

As part of our T2 stakeholder engagement we have reconfirmed with UKPN the preferred solution and the timescales for this investment.

Stakeholder and ESO Views

UKPN is satisfied with the solution and the commercial arrangements. We have agreed to continue to work closely together throughout during land negotiations and consenting activities.

NGET and the ESO have agreed all commercial terms.

Risks associated with preferred option

A number of risks have been identified with this project, although most have a low-impact on the project. There are three medium-impact, those with the greatest likelihood (20% to 40% likely) relate to the purchase of land and securing planning consent. A siting study has been carried out which has identified a preferred site. The siting study considered the risks to securing planning consents; and engagement with the land owner has commenced.

Associated CBAs

The following CBAs are associated with new GSPs (non-HS2 related).

Project	CBA Reference
[redacted]	NGET_A8.03_Demand_CBA09_[redacted].xlsb
[redacted]	NGET_A8.03_Demand_CBA01_[redacted].xlsb

8.3. Demand driven additional SGT example – Fawley 132kV (Whole System consideration)

The investment is required following a Connection Application on 13th September 2018 by Southern Electric Power Distribution (SEPD) [redacted] SGT at Fawley substation, to mitigate forecasted non-compliance issues within their network. This investment is in the early development phase 4.0.

Fawley Grid Supply Point supplies the Isle of Wight within the Southern Energy Power Distribution (SEPD) network, with a high volume of embedded generation. In 2018, SEPD completed an extensive technical report that detailed the constraints of the current network topology, taking into account the increase in applications for future embedded connections.

Under the DNO's security criteria (P2/6), certain types and sizes of embedded generation are not included in the assessment of security of supply. When studying the network under peak demand conditions and discounting this embedded generation as per the P2/6 guidelines, SEPD have reported that certain N-2 scenarios are forecast to cause thermal overloads. Conversely, under minimum demand conditions and an N-2 scenario, large amounts of embedded generation are again forecast to lead to thermal overloads and/or constraints in the Isle of Wight demand group.

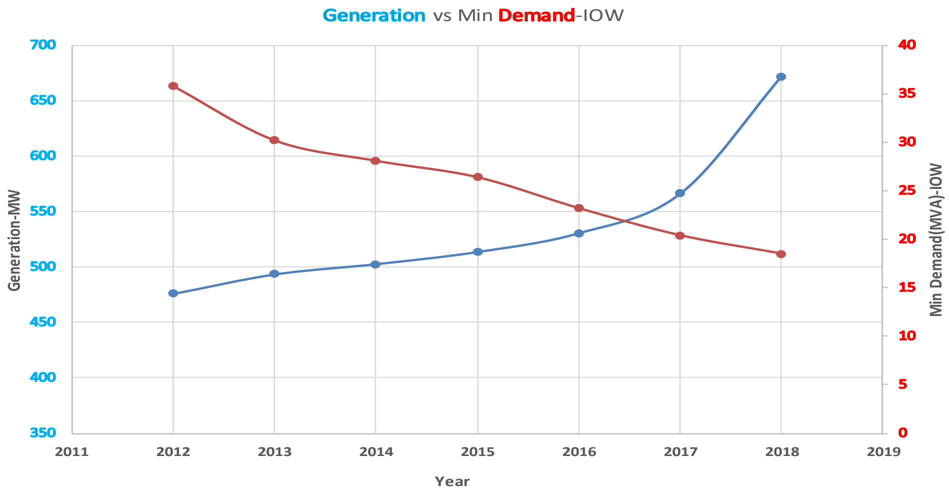


Figure 10 Graph Showing Embedded Generation vs Min Demand – Isle of Wight

Option 1 (Preferred) Install [redacted] SGT at Fawley 400/132kV Grid Supply Point ~ £[redacted]m

This option involves the installation of [redacted] 400/132kV 240MVA SGT at Fawley Grid Supply Point. Existing spare bays will be utilised on both the 400kV and 132kV sites, with new equipment installed where required. This solution resolves the forecasted N-2 compliance issues within the DNO network. There are significant subsidence issues at the Fawley site, although this can be overcome by installing piled foundations on all new equipment.

Option 2 132kV circuit Reinforcement ~ £[redacted]m

This option considers reinforcement within the 132kV network, by installing a second 132kV circuit between Fawley North and Fawley South, Fawley South and Marchwood, Fawley North and Lynes Common and finally between Lynes Common and Marchwood. In addition to the high cost, the long lead times required to consent and construct this new overhead line route would mean that delivery of this solution would take place several years after the demand group becomes non-compliant with the DNOs demand security standards (P2/6).

Option 3 Active Network Management ~ £[redacted]m

This option proposes a smart solution (ANM) to dynamically manage the power flow on the SEPD circuits in real time, by assigning and despatching export capacity to generator sites, with the aim of directing flows over the best routes across the network under both system intact and outage conditions. However, without the installation of additional transformer capacity or DNO circuits described in options 1 and 2 respectively, this solution would result in generation restrictions in the DNO network that would make it uneconomic in the long-term[6], and reduce the contributions and significant benefits of low carbon generation.

Option	Cost (£m)
Option 1 (preferred): Additional SGT	[redacted]
Option 2: 132kV circuit reinforcement	[redacted]
Option 3: Active Network Management	[redacted]

Table 5 Fawley Options summary (£m)

[6] Based on constraining 600MW for 3 hours a day for 30 days over the summer period, the cost of constraining the embedded generation is ~£4m per year.

Stakeholder engagement

As with all forecast non-compliances of this type, National Grid worked closely with the DNO, proposing and costing options for reinforcement within the DNO network in addition to new or upgraded supplies from the transmission system to identify the most appropriate whole system solution. Against this background, SEPD supports the investment decision taken.

ESO Views

The ESO supports the investment decision and has contracted with NGET.

Risks associated with the preferred option

The most likely risk with this project is the ground conditions at Fawley (40% to 60% likely). As this is an existing site there are known subsistence issues. These will be taken into account as the project development continues.

Associated CBAs

The following CBAs are associated with new SGTs at existing sites.

Project	CBA Reference
[redacted]	NGET_A8.03_Demand_CBA06_[redacted].xlsb
[redacted]	NGET_A8.03_Demand_CBA08_[redacted].xlsb
[redacted]	NGET_A8.03_Demand_CBA02_[redacted].xlsb
[redacted]	NGET_A8.03_Demand_CBA10_[redacted]xlsb

9. Summary of Cost Benefit Analysis

In total, we have completed 10 CBAs for projects covered by this justification report.

The following table shows the NPV of the preferred option against the other options considered[7].

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.

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]	[redacted]						Best whole system solution agreed with UKPN and one-off charge for incremental cost
[redacted]	[redacted]	[redacted]							Lowest NPV solution selected
[redacted]	[redacted]	[redacted]							Customer has opted to pay incremental cost over lowest NPV solution
[redacted]	[redacted]								Second option considered but it cost ~£30m more than the baseline / preferred option
[redacted]	[redacted]	[redacted]	[redacted]						Lowest NPV solution selected

[7] Some options may have been excluded from the detailed CBA analysis if the option is demonstrably more expensive or does not meet the customer's need

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]	[redacted]						Lowest NPV solution selected
[redacted]	[redacted]	[redacted]							Customer has opted to pay incremental cost over lowest NPV solution
[redacted]	[redacted]	[redacted]	[redacted]						Lowest NPV solution selected
[redacted]	[redacted]	[redacted]	[redacted]						Lowest NPV solution selected
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Lowest NPV does not meet customers increased demand growth requirements

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.

Project	Reference (and Excel filename)
[redacted]	NGET_A8.03_Demand_CBA09_[redacted].xlsb
[redacted]	NGET_A8.03_Demand_CBA06_[redacted].xlsb
[redacted]	NGET_A8.03_Demand_CBA08_[redacted].xlsb
[redacted]	NGET_A8.03_Demand_CBA04_[redacted].xlsb
[redacted]	**NGET_A8.03_Demand_CBA03_[redacted].xlsb**
[redacted]	NGET_A8.03_Demand_CBA05_[redacted].xlsb
[redacted]	**NGET_A8.03_Demand_CBA02_[redacted].xlsb**
[redacted]	NGET_A8.03_Demand_CBA07_[redacted].xlsb
[redacted]	**NGET_A8.03_Demand_CBA01_[redacted] xlsb**
[redacted]	NGET_A8.03_Demand_CBA10_[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 uncertainty 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 demand connections we will ultimately have to deliver in the T2 period is dependent on customer requirements, introducing uncertainty. We have therefore developed a volume driver uncertainty mechanism, based on unit cost allowances to deal with this uncertainty, as shown below.

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

Key stats:	No.
Models considered	9
Input data points (projects)	33

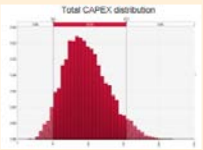
Uncertainty characteristics

i) Risk and ownership

- Customer need, associated type of connection and potential whole system alternatives 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 £147m *(90% of the Monte Carlo simulations guided by the Future Energy Scenarios have a total cost between £54m and 201m)*



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

- UCA per SGT and per km of OHL – reducing allowances by >£185m as system needs changed
- Substation UCA could have been more cost reflective of the projects delivered. It was based on shared infrastructure sites for connection; but the volume of higher cost single customers connecting has increased
- We delivered several connections without the need for an SGT; not triggering allowance but incurring cost

ii) Learnings for T2

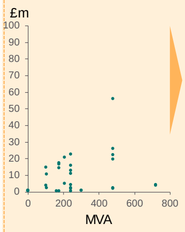
- UCA should reflect evolving customer:
  - e.g. demand from industrial facilities decline, while demand from data centres rises
  - reflect lower cost, innovative connection solutions, such as tertiary winding connections
- A more cost-reflective UCA designed through rigorous statistical analysis would better protect consumers and companies
- Revenue calculation based on latest forecast of outputs can smooth customer charges

T2 proposals

i) Proposed approach and benefits

- Separate UCA for connection and infrastructure sites
- Connection sites UCA split by new *vs* existing and new <50MVA
- Infrastructure sites UCA split SGT *vs.* no SGT requirement
- The new UCAs are designed using established statistical techniques and stress-tested using Monte Carlo simulations to ensure accuracy and resilience
- Revenue calculated based on latest 5-year RRP forecast of outputs in order to minimise customer charging volatility

Inputs (£m vs. MW)



Proposed Design

Substation (sub) costs

Connection Projects

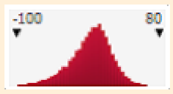
- Capacity delivered at new subs: [redacted] **£m/MVA**
- Capacity delivered at existing subs: [redacted] **£m/MVA**
- Capacity delivered at new sub < 50MVA: [redacted] **£m/SGT**

Infrastructure Projects

- New SGT delivered: [redacted] **£m/SGT**
- No SGT required: **£**[redacted]**m**

New circuit details in Annex ET.12

Testing (cost vs. allowance)



Mean: -£4.27m

Std. Dev.: £22.58m

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

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

11. Conclusions

Our business plan for demand 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 need to invest and the preferred solution for each project has been rigorously tested with DNOs, to assure ourselves that the right whole system solution is being undertaken at the right time.

This investment decision pack, comprising this justification report, three detailed case studies, and ten 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 most 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 and noted any additional commercial arrangement that might be in place with the customer to directly pay for additional scope they might have requested.

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.

We have developed a robust unit cost allowance to manage demand connection volume uncertainty in the T2 period. This mechanism will automatically adjust allowances up and down depending on customer requirements.