Scottish & Southern Electricity Networks

RIIO-ED2 Engineering Justification Paper (EJP)

Egham 33/11kV Primary Transformers and 33kV Circuits Reinforcement

Investment Reference No: 53/SEPD/LRE/EGHA

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Definitions and Abbreviations

Acronym	Definition
AIS	Air-insulated Switchgear
ASCR	Aluminium Conductor Steel Reinforced
BSP	Bulk Supply Point
CBA	Cost Benefit Analysis
CBRM	Condition Based Risk Management
CEM	Common Evaluation Methodology
CI	Customer Interruptions
CML	Customer Minutes Lost
CT	Consumer Transformation
DFES	Distribution Future Energy Scenarios
DNO	Distribution Network Operator
EJP	Engineering Justification Paper
ESA	Electricity Supply Area
EV	Electric Vehicle
FCO	First Circuit Outage
FES	Future Energy Scenarios
GIS	Geographic Information System
GM	Ground Mounted
GSP	Grid Supply Point
HI	Health Index
IDP	Investment Decision Pack
LCT	Low Carbon Technology
LEP	Local Enterprise Partnership
LI	Load Index
LRE	Load Related Expenditure
LW	Leading the Way
NPV	Net Present Value
OHL	Overhead Line
PM	Pole Mounted
PV	Photovoltaics
RSN	Relevant Section of Network
SCO	Second Circuit Outage
SSEN	Scottish and Southern Electricity Network
SP	Steady Progression
ST	System Transformation
XLPE	Cross-linked Polyethylene

1 Executive Summary

Our proposed investment at Egham primary substation and 33kV circuits will deliver P2/7 compliance for investment of £3.82m during RIIO-ED2.

The primary investment driver for this scheme is load related P2/7 compliance issue at Egham primary. The P2/7 compliance issues are apparent under four scenarios (System Transformation, Consumer Transformation, Leading the way, and Steady Progression) requiring investment in ED2 due to forecast demand growth from our Stakeholder supported Distribution Future Energy Scenario (DFES).

Accelerating progress towards a net zero world

The EJP considers a range of options to address the P2/7 compliance issues, setting out the options that have been considered and rejected prior to the CBA analysis, and the short list of those options included within the analysis, with a clear rationale for including or excluding each option.

The Cost Benefit Analysis results shown below in table 1 demonstrates that the most cost-effective solution, that delivers the best value for consumers in terms of the 45 year Net Present Value, is option 4 which will utilise flexible solutions to defer conventional reinforcement followed by adding new assets.

Options	NPV After 45 Years (£k)	Investment (£k)
Option 2 – Replace existing 33/11kV transformers and 33kV circuits	-3,313	4,458
Option 3 – Addition of a 33/11kV transformer and 33kV circuit	-2,678	3,674
Option 4 – Flexible Solution followed by Add New Assets	-2,537	3,822

Table 1: CBA Results

Following the optioneering and detailed analysis, as set out in this paper, the proposed scope of works for Option 4 is:

Asset	Volume	Costs
33kV Transformer (GM)	1	[redacted]
33kV CB (Gas Insulated Busbars)(ID)(GM)	1.00	[redacted]
33kV UG Cable (Non Pressurised)	5.00	[redacted]
London Region - Increased highway management	1	[redacted]
HDD - Thames crossing	1	[redacted]
Total		£3,673.8k

Table 2: Option 4 Cost Breakdown (excluding Flexibility costs).

The costs listed above reflect the costs associated with the conventional solution. In addition to this there will also be costs for procuring flexible services to reduce the peak demand. It is anticipated the cost for procuring flexibility will be £148.3k bringing the total project cost to £3,820k.

This scheme delivers the following outputs and benefits:

- Uplift in network capacity of 28MVA to meet the needs of our customers.
- Improves the Load Index from LI5 to LI1 by end of ED2.
- Facilitates the efficient, economic, and co-ordinated development of our Distribution Network for Net Zero.

The cost to deliver the preferred solution is £3.82m and the works are planned to be completed in 2027. This EJP investment sits within our Net Zero Totex ask.

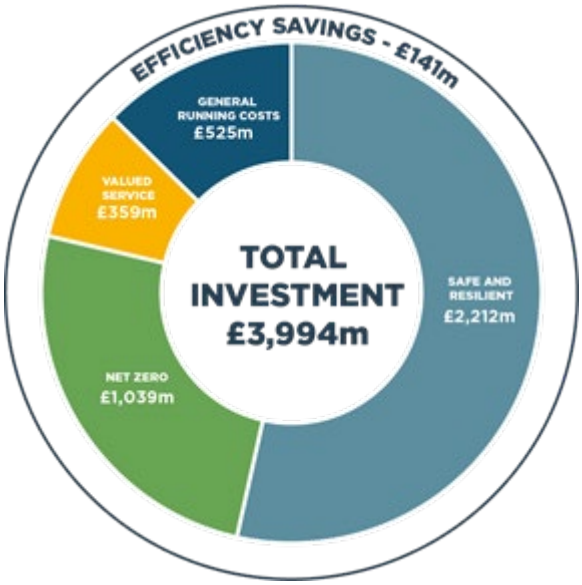


Figure 1: SSEN total investment cost within RIIO ED2

2 Investment Summary Table

Table 3 below provides a high level summary of the key information relevant to this Engineering Justification Paper (EJP), which discusses the investment proposals for Egham 33/11kV Primary substation.

Name of Scheme	Egham 33/11kV Primary Transformers and 33kV Circuits Reinforcement		
Primary Investment Driver	Load – P2 compliance – Thermal		
Scheme reference/mechanism or category	53/SEPD/LRE/EGHA		
Output references/type	• 33/11kV Transformer • 33kV Circuits • Flexibility		
Cost	£3.82m		
Delivery year	2023/24-2026/27		
Reporting table	CV1: Primary Reinforcement		
Outputs included in RIIO-ED1 Business Plan	No		
Spend apportionment (£m)	**ED1**	**ED2**	**ED3+**
	0	3.82	0

Table 3: Investment Summary

3 Introduction

Our ***Load Related Plan Build and Strategy (Annex 10.1)***[1] sets out our methodology for assessing load-related expenditure and describes how we use the Distribution Future Energy Scenarios (DFES) 2020 as the basis for our proposals. We have established a baseline view of demand, providing a robust projection of the drivers of load-related expenditure for the ED2 period. Our ex-ante baseline funding request is based on the minimum investment required under all credible scenarios and is strongly supported by our stakeholders. Our plan will create smart, flexible, local energy networks that facilitate the accelerated progress towards net zero – with an increased focus on collaboration and whole-systems approaches.

This investment is a component of our strategic goal of 'Accelerating progress towards a net zero world'.

Section 4 of this Engineering Justification Paper (EJP) describes our proposed load related investment plan for the reinforcement of Egham primary in RIIO-ED2. The primary driver considered within this paper is load related P2/7 compliance issue due to forecast demand growth from our Stakeholder supported Distribution Future Energy Scenario (DFES).

This EJP provides high-level background information for this proposed scheme explaining the existing network arranges, the load growth forecasts through the Distribution Future Energy Scenarios (DFES) and setting out the need for this project. The Detailed Analysis section of the EJP describes the network studies undertaken, detailing the results which further justify the need of the proposed investment.

Section 5 provides an exhaustive list of the options considered through the optioneering process to establish the most economic and efficient solution. Each option is described in detail, with the EJP setting out the

[1] ***SECTION D: (Chapter 10), Responding to the net zero Opportunity, (Annex 10.1), Load Related Plan Build and Strategy***

justification for those options which are deemed unviable solutions, and therefore not taken forward to the Cost Benefit Analysis.

Section 6, Cost Benefit Analysis (CBA) Summary, provides the comparative results of all the options considered within the CBA and sets out the rationale and justification for the preferred solution. This section also describes how we have established the cost efficiency of the plan with reference to the unit costs that have been chosen.

Finally, **Section 7** of this EJP also sets out the deliverability of the plan for RIIO-ED2 and this proposed investment.

4 Background Information and Analysis

4.1 Existing Network Arrangement

Egham Primary is located within the Longford - Staines region of the SEPD licence area. This substation is supplied from the Staines BSP. Egham primary currently supplies 10,091 customers via 11 kV circuits. The 2019/20 peak demand was 24.7 MVA and there is currently no embedded generation connected.

Egham 33/11kV Primary substation is currently fed via dual 33kV circuit from Staines BSP as shown in Figure 2 below. The circuits are comprised of both overhead line and cable sections, of which the overhead line section limits First Circuit Outage (FCO) capacity of Egham to 28MVA in winter and 23.2MVA in summer. The two existing 33/11kV transformers at Egham Primary are Continuous Emergency Rating (CER) transformers with a maximum rating of 30MVA for the whole year and have a common neutral connection. The 11kV switchboard is suitably rated and has been installed with a spare third transformer incomer circuit breaker.

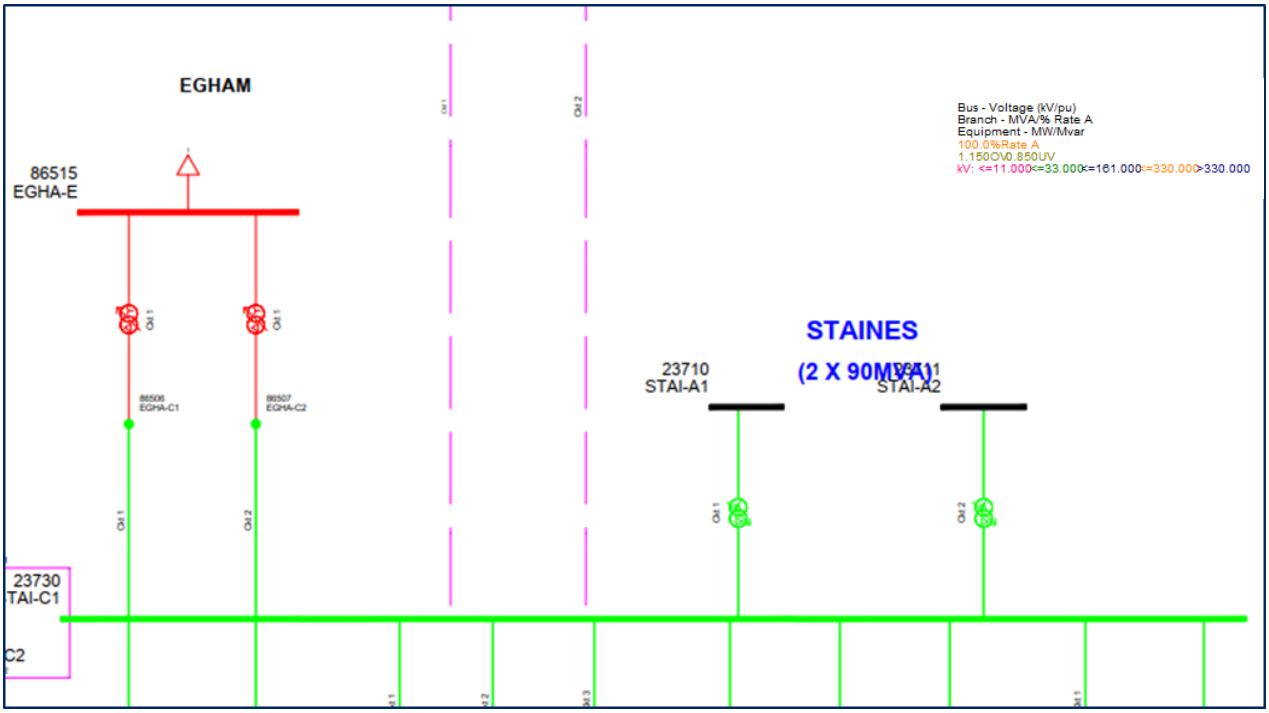


Figure 2: Egham Network Arrangement SLD.

Figure 3: Egham Substation.

4.2 Local Energy Plan

In 2020, Surrey county council has published Surrey's Climate Change Strategy[2]. The strategy document sets out their ambition to support the national decarbonisation ambition by leading renewable energy generation expansion and bringing low carbon heating into Surrey homes through smart, decentralised systems. The target is to achieve target is 15% of energy from solar PV by 2032. The actions to support this energy ambition are as follows:

- By 2020:
  - Carry out a Surrey-wide feasibility study to identify land and buildings where solar PV could be installed.
  - Undertake partnership working with districts and boroughs to evaluate the potential to produce low or zero carbon energy focused projects, e.g. low-head hydropower.
  - Look to connect all Surrey County Council buildings to CHP or other forms of DHN's or cooling systems where possible.
  - Develop a Surrey-wide Renewable Energy Strategy that explores potential opportunities for renewable energy, decentralised systems and low carbon heating systems e.g. heat pumps and Combined Heat and Power.

- By 2035:
  - Identify potential sites for other types of renewable energy installations e.g. wind turbines.

[2] https://www.surreycc.gov.uk/people-and-community/climate-change/what-are-we-doing/climate-change-strategy

- All authority buildings will be considered for solar PV panels with the intention of selling excess electricity back to the National grid.
- Work with Surrey Environment Partnership to scope the potential to develop more energy from anaerobic digestion.
- Conduct a county-wide analysis for the potential for district heating networks.
- Scope the potential for establishing low cost capital finance such as community revolving funds.
- Develop local requirements for decentralised energy supply in local plans which new developments will be required to comply with.
- Work with local planning officers and building control to encourage and facilitate zero carbon heating systems for new build development.

4.3 Demand and Generation Forecast for Egham Primary

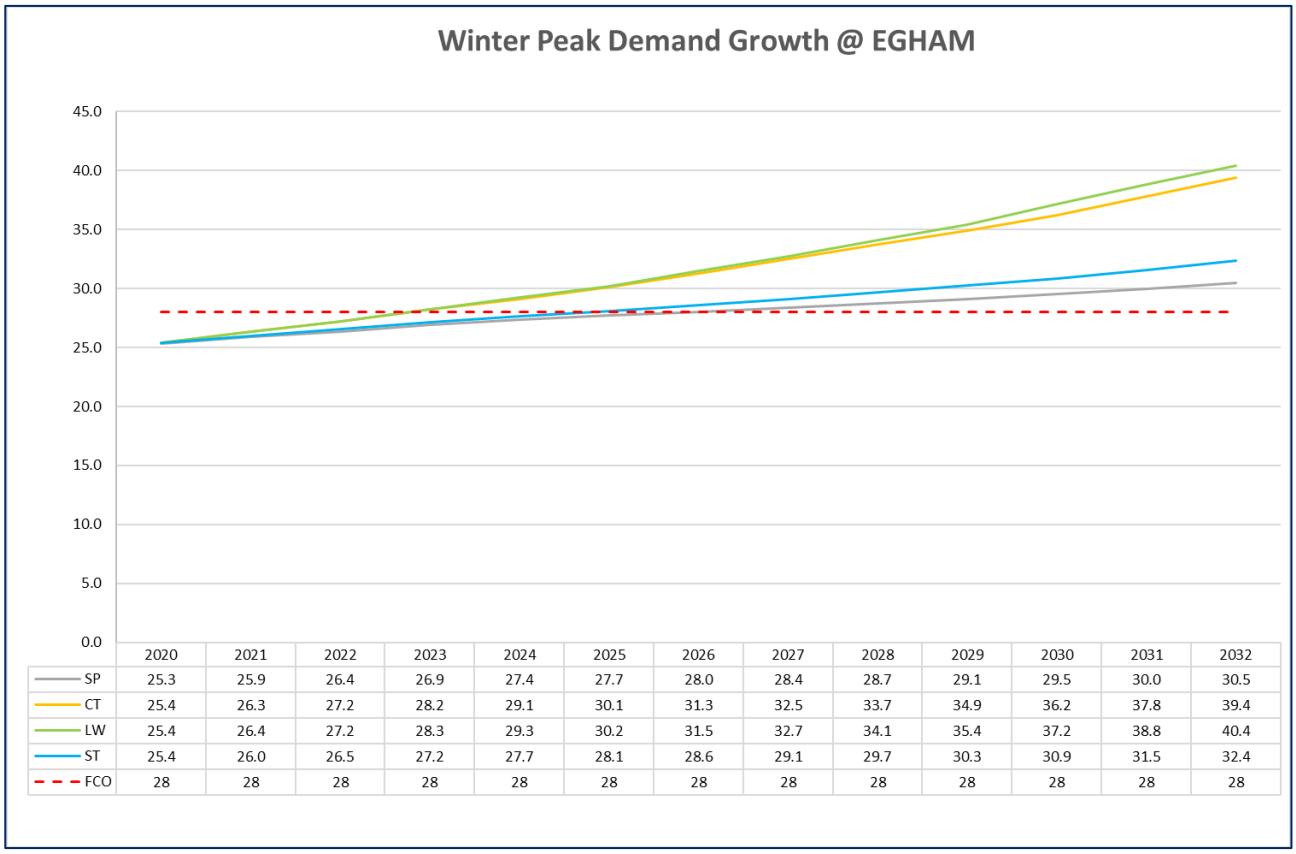
We have carried out extensive scenario studies – the Distribution Future Energy Scenarios (DFES). The basis for this work is National Grid's Future Energy Scenarios (FES) 2020. This framework comprises four potential pathways for the future of energy based on how much energy may be needed and where it might come from. The variables for the four scenarios are driven by government policy, economics and consumer attitudes related to the speed of decarbonisation and the level of decentralisation of the energy industry. We have worked closely with our partner Regen to develop the forecasts between 2020 and 2050 through enhanced engagement with the local authorities, local enterprise partnerships (LEPs), devolved governments, community energy groups and other stakeholders.

Based on the enhanced stakeholder engagement feedback, we have chosen Consumer Transformation as the baseline scenario for our investment. We are protecting customers from the impact of forecasting uncertainties through our baseline funding only including load related investment required in the first two years in the RIIO-ED2 period, unless it is also required by other net zero scenarios. Full details on our DFES methodology, stakeholder input and regulatory treatments of load related investment can be found in the ***Load Related Plan Build and Strategy (Annex 10.1)***[3].

Figure 4 to 6 shows the demand projections in MW of Egham primary substation for all forecast scenarios and the first circuit outage (FCO) limit for this substation for all FES scenarios. In this case, the FCO limit (see section 5.3) is exceeded for the Consumer Transformation (CT) and Leading the Way (LW) scenarios in 2023/2024, System Transformation (ST) scenario in 2025/2026 and Steady Progress (SP) in 2026/27. This scenario modelling confirms the certainty of this investment in RIIO-ED2. The current Load Index (LI) for Egham is LI2 (90.3%) and it will be LI5 (116%) by the end of ED2 period without intervention.

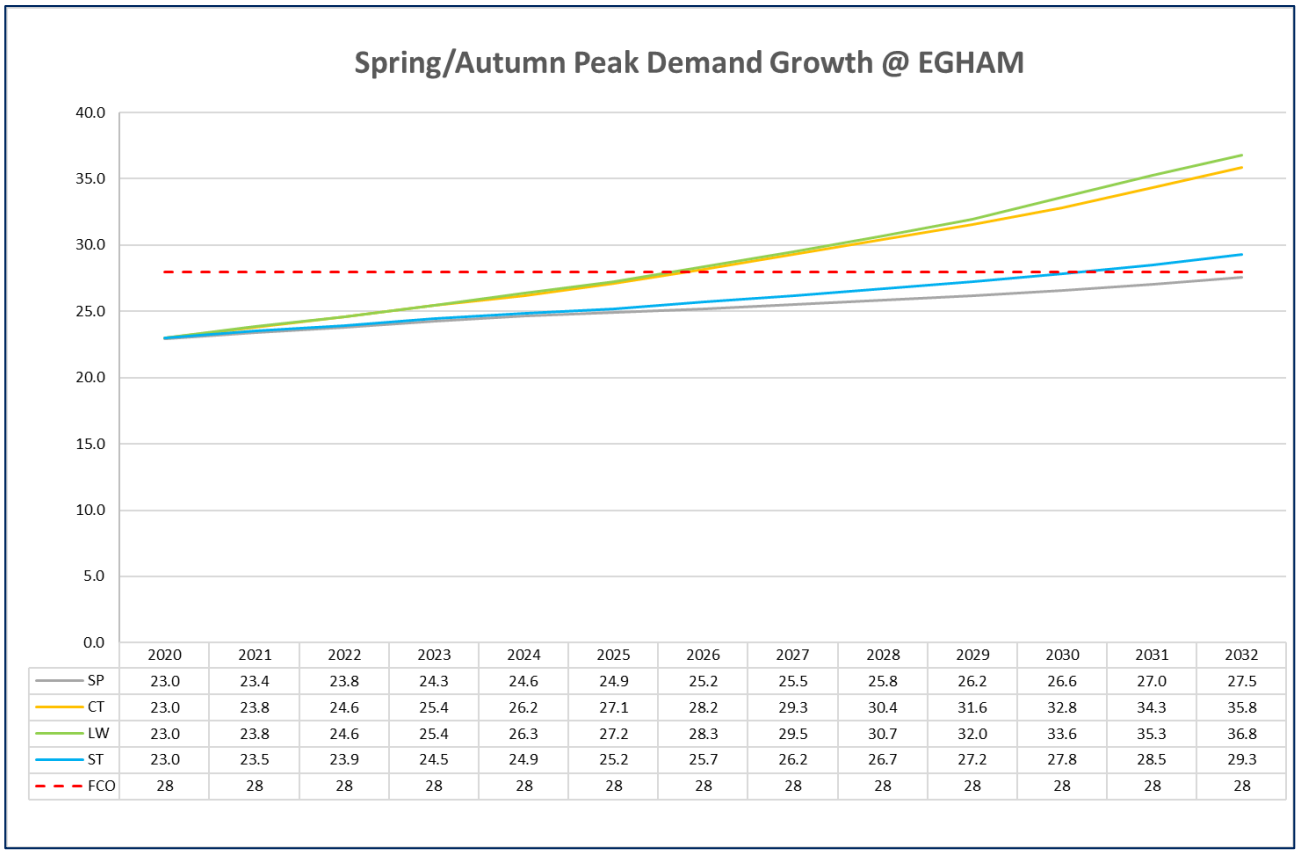
Network interventions are required to address this issue as not doing anything would result in a licence condition breach and potentially a wide-spread blackout in the areas supplied by Egham Primary.

[3] Refer to Annex Load Related Plan Build and Strategy (Annex 10.1)



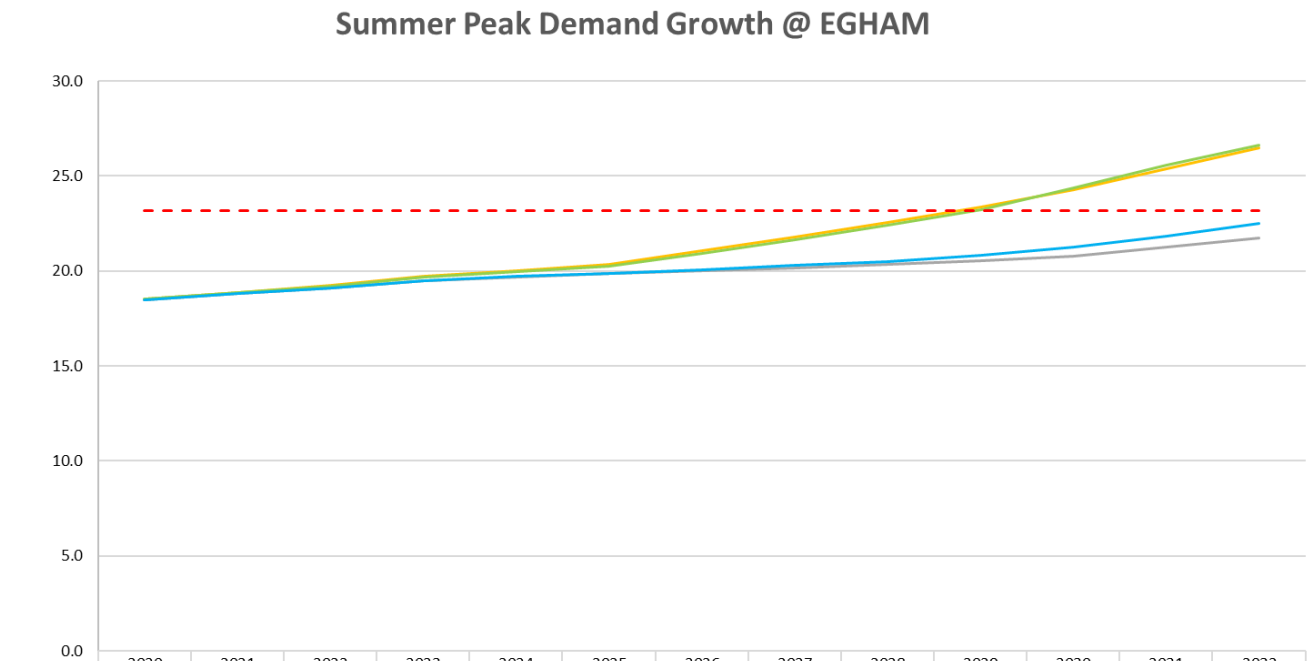
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
SP	25.3	25.9	26.4	26.9	27.4	27.7	28.0	28.4	28.7	29.1	29.5	30.0	30.5
CT	25.4	26.3	27.2	28.2	29.1	30.1	31.3	32.5	33.7	34.9	36.2	37.8	39.4
LW	25.4	26.4	27.2	28.3	29.3	30.2	31.5	32.7	34.1	35.4	37.2	38.8	40.4
ST	25.4	26.0	26.5	27.2	27.7	28.1	28.6	29.1	29.7	30.3	30.9	31.5	32.4
FCO	28	28	28	28	28	28	28	28	28	28	28	28	28

Figure 4: Egham winter peak demand growth.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
SP	23.0	23.4	23.8	24.3	24.6	24.9	25.2	25.5	25.8	26.2	26.6	27.0	27.5
CT	23.0	23.8	24.6	25.4	26.2	27.1	28.2	29.3	30.4	31.6	32.8	34.3	35.8
LW	23.0	23.8	24.6	25.4	26.3	27.2	28.3	29.5	30.7	32.0	33.6	35.3	36.8
ST	23.0	23.5	23.9	24.5	24.9	25.2	25.7	26.2	26.7	27.2	27.8	28.5	29.3
FCO	28	28	28	28	28	28	28	28	28	28	28	28	28

Figure 5: Egham spring / autumn peak demand growth.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
SP	18.5	18.8	19.1	19.5	19.7	19.9	20.0	20.2	20.4	20.6	20.8	21.2	21.7
CT	18.5	18.9	19.2	19.7	20.0	20.4	21.0	21.8	22.6	23.4	24.3	25.4	26.5
LW	18.5	18.9	19.2	19.7	20.0	20.3	20.9	21.7	22.4	23.2	24.4	25.6	26.6
ST	18.5	18.8	19.1	19.5	19.7	19.9	20.1	20.3	20.5	20.8	21.3	21.8	22.5
FCO	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2

Figure 6: Egham summer peak demand growth.

Peak demand is expected to increase at Egham primary by approximately 7.8 MVA from 2019/20 to 2027/28 when following the CT scenario in winter. The projected primary demand of 32.5 MVA is split below by demand type. The chart shows the largest impact on demand in the area is from Heat pumps, equating to 10% of the overall projected demand.

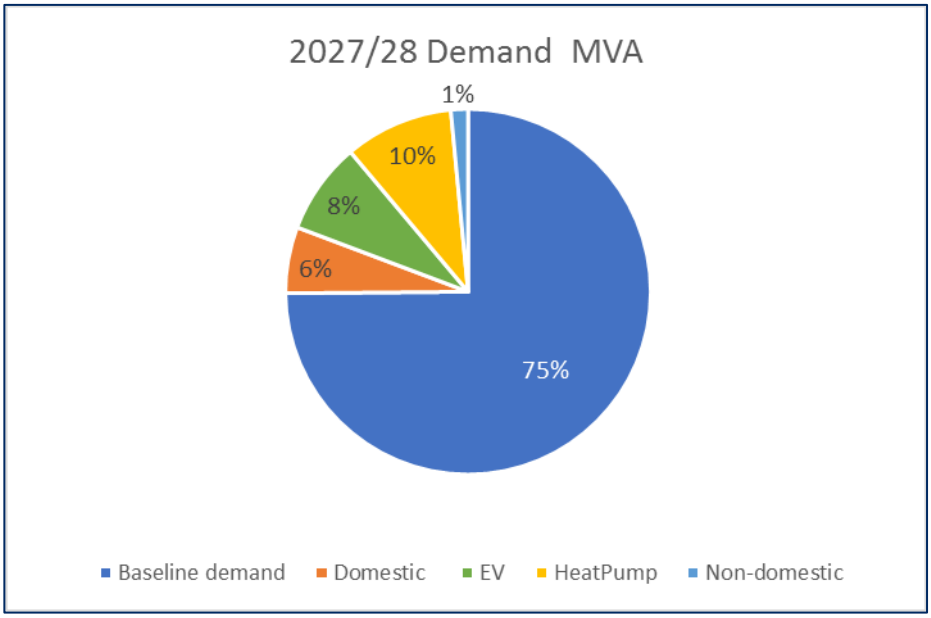


Figure 7: 2027/28 Demand Breakdown

4.4 Existing Asset Condition

The existing assets are in good condition and are either HI1 or HI2 with no plans for non-load investment within the ED2 period.

4.5 Thermal Flow Analysis

The results of the thermal analysis are shown in the table below.

Year	Demand Group	Season	Group Class	Contingency	Loaded Circuit / Transformer	FCO Demand to be Met	FCO Available Capacity
2024	Egham Primary T1 & T2	Winter	C	Fault on Staines to Egham circuit 1	Egham T2& Staines to Egham circuit 2	28.2 MVA	**28 MVA**
2024	Egham Primary T1 & T2	Spring/ Autumn	C	Fault on Staines to Egham circuit 1	Egham T2& Staines to Egham circuit 1	25.4 MVA	**28 MVA**
2024	Egham Primary T1 & T2	Summer	C	Fault on Staines to Egham circuit 1	Egham T2 Staines to Egham circuit 2	19.7 MVA	**23 MVA**

Table 4 First Circuit Outage (FCO) Analysis in 2023/24 – CT scenario

The results highlight that the Egham 33/11kV transformer will become overloaded and subsequently reinforcement is required due to non-compliance with P2/7 under FCO conditions. The current Load Index (LI) for Egham is LI2 (90.3%) and it will be LI5 (116%) by the end of ED2 period without intervention.

4.6 Voltage Level Assessment

Voltages at the 33kV and the 11kV busbars remain within statutory limits as shown in Appendix 2. Reinforcement is not required as voltage compliance is met.

4.7 Fault Level Analysis

There are no fault level issues unless the network has significant changes on the conductor sizes. The results of this analysis are shown in Appendix 2.

4.8 Network Analysis Summary

The analysis above has shown that intervention to reinforce Egham primary substation will be required within RIIO-ED2 to mitigate the overloading and P2/7 non-compliance issue. Reinforcement is not required due to voltage or fault level as these remain within limits.

5 Summary of Options Considered

This section of the report sets out the investment options that are considered when resolving overload issues. As described below a holistic approach is taken to ensure investment options which are both least regrets and represents best value for money for network customers are identified.

5.1 Whole System Considerations

We have additionally considered the potential for using Whole System solutions (involving collaboration with third parties) to deliver this investment programme. We set out our assessment in Appendix 3. This follows our standardised approach for embedding Whole System considerations into our load and non-load investment decisions (in line with Ofgem's ED2 business plan guidance), as described in our ***Whole System (Annex 12.1)***.

Our assessment enables us to take a proportionate consideration of Whole System options, based on the feasibility of such options existing and materiality of the costs involved.

In this case, our Whole Systems assessment finds that this programme is not expected to have any wider Whole System interactions and there are no feasible Whole Systems solutions.

5.2 Summary of Options

Table 5 provides a high-level summary of the 4 investment options under consideration along with the advantages and disadvantages associated with each. A more detailed description of each option is then provided within the proceeding sub-sections.

Option	Description	Advantages	Disadvantages	Result
1. Do Minimum	It is normally done by carrying out demand transfer from the overloaded demand group to another.	Minimum cost and workload;	Does not increase network capacity; further reinforcement may still be required.	Not Progressed to CBA
2. Asset Replacement	The replacement of the full overloaded equipment including: • 2 x 33/11kV Transformer • 9.1 km of 33kV Circuit	Allow latest and most efficient technology to be installed; Increase network resilience; Reduce environmental impact.	Can incur long outages if replacement cannot be built offline; Some non-overloaded asset may also need to be replaced in-line with the new equipment.	Progressed to CBA
3. Add New Assets	When overloaded equipment is already reached maximum rating, new equipment will be added into existing network. This involves: • a new 33/11kV transformer at Egham • a new 5km 33kV circuit between Egham and Staines • new switchgear at Staines	Increase network resilience; Shorter outage time; Long term benefit.	Additional land purchase maybe required; Can incur large civil costs; Required new control strategy.	Progressed to CBA
4. Flexibility Solution followed by Add New Asset	Flexible service contracts to reduce peak demand and defer capital investment	Relatively low cost Defers need for network reinforcement	Amount of flexibility depends on location-specific resources and interests. CAPEX may still be required.	Progressed to CBA

Table 5: Summary of Investment Options

5.3 Detailed Option Analysis

5.3.1 Option 1: Do-Minimum

Estimated Cost: £N/A

Egham Primary is interconnected at 11kV to nearby primary substations, notably Causeway Primary, for system security and transfer of load for unplanned outage events. As part of a customer connection, it is planned for 2MVA of load to be transferred from Egham to Causeway to allow for the customer connection at Egham. The current network configuration will not allow for any further load transfers.

As this option does not resolve the P2/7 non-compliance and the substation load index will still be LI5 by the end of ED2 therefore result in poorer guaranteed standard performance and customer interruptions, it is rejected.

5.3.2 Option 2: Asset Replacement

Estimated Cost: £4,458.2k

The overloaded equipment at Egham Primary is the two 33/11kV transformers which are currently rated at 30MVA. It is possible to replace these transformers with two units that are rated at 40MVA from existing suppliers.

The existing 33kV circuits between Staines BSP and Egham Primary consist of and a single section of overhead line and four separate sections of underground cable. All cable and overhead line sections will be replaced and upgraded to/above rating 43.5/39.4MVA to lift the FCO capacity to 38MVA at Egham Primary, which is limited by the 11kV incomer circuit breaker. The section with oil filled cable will be replaced with XLPE cable. The combined total of 33kV circuit requiring reinforcement is 3.6km of Overhead Line and 5.49km of underground cable.

Figure 7 shows the existing circuit route, which leaves Staines BSP via a short cable section onto a dual circuit wood pole Overhead line crossing over a railway line and running alongside the A30. The circuits then transfer back to cables to cross underneath the M25. The route then run alongside the M25, crossing the Thames and around the M25/A30 junction before heading into Egham Primary in the centre of the town. Replacement of the circuits might prove challenging with interfaces with both Network Rail and Highways.

Figure 8: Cable route between Egham and Staines BSP

5.3.3 Option 3: Add New Assets

Estimated Cost: £3,673.8k

The existing 11kV switchboard at Egham Primary is configured to accept an additional transformer, however at Egham Primary substation, there is limited available space for addition of extra assets and little option to increase substation footprint. The existing 33kV circuits are also thermally overloaded so cannot supply the additional demand. This option is to install a new 33kV cable circuit from Staines BSP connected directly to the new transformer. This removes the need for the 33kV switchgear at Egham but will require an extension of the 33kV switchboard at Staines.

The 33kV cable route would need to cross the river Thames and the A30 including going around the junction of the M25 and the A30. The circuit length is 5km.

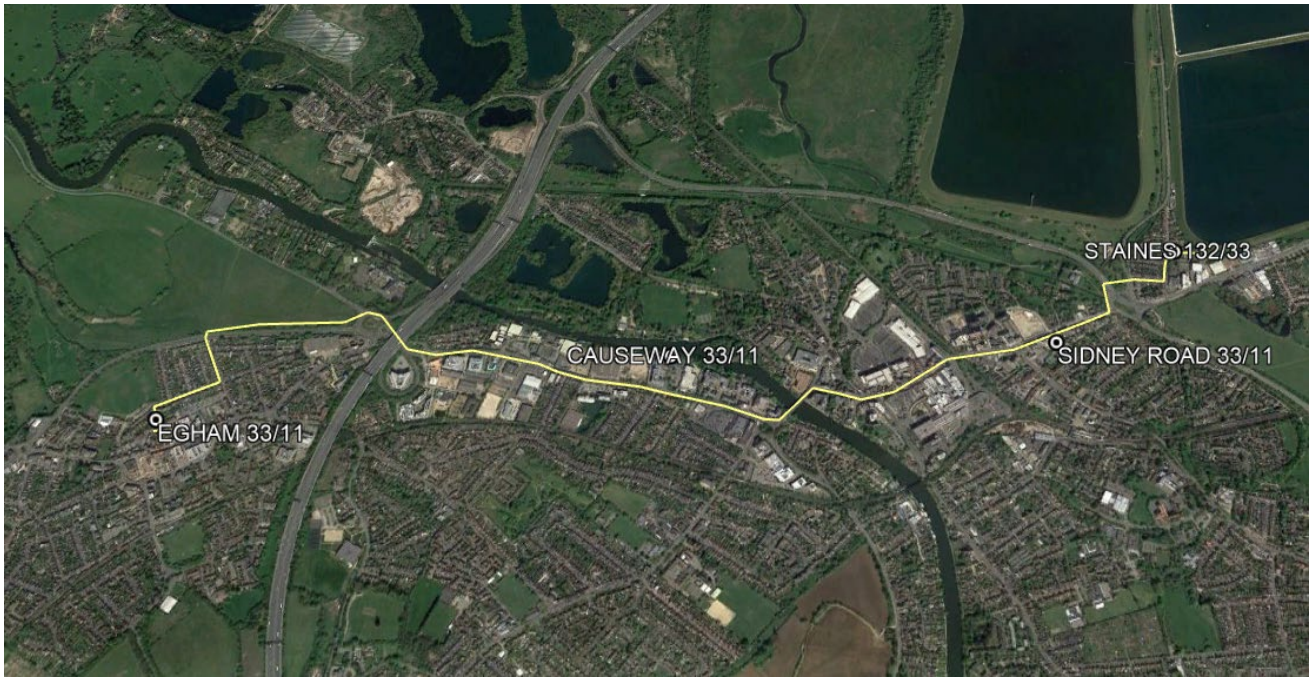


Figure 9: Proposed New Cable Route between Egham and Staines

The additional circuit will give a new FCO capacity at Egham Primary of 56MVA, which will be limited by the two existing 33kV circuits.

Ofgem's RIIO-ED2 standard CBA template was used to assess costs and benefits of the conventional Options 2 and 3. Capital reinforcement costs, CI/CML penalties, network losses and other societal benefits are the key parameters used in this CBA. The customer interruptions / customer minutes lost (CI/CML) were calculated based on the potential overload and the probability of failure. The CI and CML values used are shown in Appendix 1. As a result of the CBA assessment, Option 3 came out as the preferred conventional investment option which is used to feed into the Common Evaluation Methodology (CEM)[4] Flexibility CBA to determine if there are economic benefits in deferring this capital investment. With this option, the LI will be LI1 by the end of ED2 period.

5.3.4 Option 4: Flexible Solution

Estimated Cost: £3,822k

The CEM framework would evaluate options around timing of network investments, in particular taking into account:

- the range of different options available (e.g., reinforcing the network, using flexibility, or doing nothing);
- the time periods in which actions can be taken; and
- the existence of uncertainty, and the impact of incremental information which becomes available over time.

[4] https://www.energynetworks.org/assets/images/Resource%20library/ON20-WS1A-P1%20Common%20Evaluation%20Methodology-PUBLISHED.23.12.20.pdf

Figure 10 below shows that the peak demand at Egham Primary exceeds the FCO rating for approximately 1 hour at a typical winter day in 2024 and the situation would be more onerous from 2024 onwards. Flexibility services could be used to reduce the peak demand forecast and it is estimated that reinforcements could be deferred by three years, after which option 3, Add New Assets, would be implemented.

The MW exceedance, the daily and annual overload hours are shown in Table 3. Flexibility unit costs of £150 per MW per hour and £150 per MWh were used as input parameters in the CEM CBA model (full details of the flexibility methodology can be found in the ***Load Related Plan Build and Strategy (Annex 10.1***).

	2021	2022	2023	2024	2025	2026	2027	2028
Hrs/day required	0	0	0	1.0	2.5	3.5	4.5	6.0
Days/yr required	0	0	0	64	64	64	64	64
Av MVA	0.0	0.0	0.0	0.20	1.10	2.10	3.30	4.50
MWh	0	0	0	4.35	55.35	158.75	305.69	494.95

Table 6: Estimated dispatch requirements for flexibility solution.

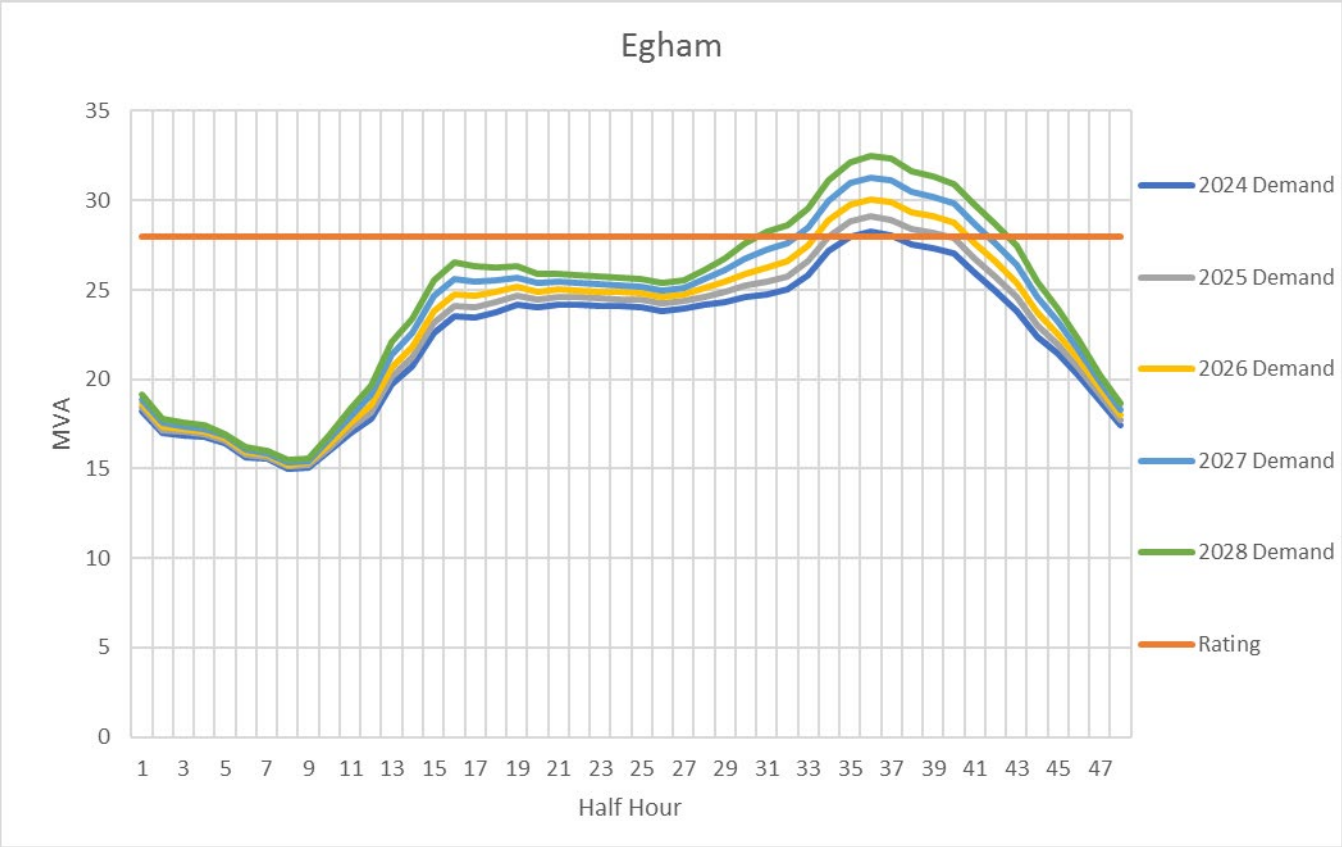


Figure 10: Egham winter peak demand 2024-2028 without flexibility services.

The CEM model outcome shows that the optimal deferral period for CT and LW is 2 years. If the future demand follows the SP or ST trajectories the reinforcement might be deferred to RIIO-ED3. Our optimal deliverability plan suggests 2026/27 for the capital delivery and the CEM net benefit result shows a positive benefit (£97,418) for this year. As the NPV result for this 3-year deferral is superior than the other two conventional options (Table 8), it is our preferred option.

Cumulative benefit of deferral (excluding benefit from further deferral, but including multi-year discount)		**Defer by 1 year(s) to 2025**	**Defer by 2 year(s) to 2026**	**Defer by 3 year(s) to 2027**	**Defer by 4 year(s) to 2028**
[1] under Consumer Transformation	*£0*	£80,372	£121,057	£97,418	£48,957
[2] under Leading the Way	*£0*	£77,834	£94,402	£64,436	-£405
[3] under Steady Progression	*£0*	£83,690	£163,676	£240,167	£313,162
[4] under System Transformation	*£0*	£83,690	£163,676	£239,769	£301,237

Table 7: Cumulative benefit of deferral

In line with our Flexibility First Approach, this project is technically compatible with a Flexibility Solution. In this case flexibility will allow us to defer the need for a conventional solution by 3 years, as such SSEN will carry out Flexibility market tests to establish the cost, location and technical capabilities of the available flexibility.

If the market test is successful, a Flexibility Solution will be employed offering value to SSEN and our customers in terms of investment deferral and optionality. Should the market test fail or only partially succeed in identifying the required Flexibility, SSEN will utilise the CEM Framework to assess the optimal, secondary solution for this location, be that a further market test for full Flexibility, accelerating the Conventional solution or a Hybrid Scheme. SSEN will also assess the potential to extend the Flexible Solution beyond the initial 3 years on an annual basis, potentially increasing the benefits of deferring the conventional solution should demand growth be lower than expected.

Further detail of our Flexibility First approach and assessment methodology can be found in ***DSO Strategy (Annex 11.1), Appendix F - Delivering Value through Flexibility.***

6 Cost Benefit Analysis

This section provides an overview of the results from the Cost Benefit Analysis (CBA). This detailed exercise has been undertaken to support the investment strategies discussed within this EJP.

6.1 CBA of Investment Options

Ofgem's RIIO-ED2 standard CBA template was used to assess costs and benefits of the conventional options for each circuit individually. Capital reinforcement costs, CI/CML penalties, network losses and other societal benefits are the key parameters used in the CBAs of the three options progressed. The customer interruptions / customer minutes lost (CI/CML) were calculated based on the potential overload and the probability of a failure.

Further information on our Cost Benefit Analysis (CBA) approach is set out within ***Cost Benefit Analysis Process (Annex 15.8)***.

6.2 CBA Results

The table below summarises the CBA outcome for all the options considered to resolve the thermal constraints at Egham primary. The CBA results show that Option 4 Flexible Solution followed by conventional reinforcement is the preferred solution due to the superior NPV value. The cost associated with this option includes the expenditure for the procurement of flexible services as well as the capital cost of the conventional reinforcement in 2027.

Options	NPV After 45 Years (£k)	Investment (£k)
Option 2 – Asset Replacement	-3,313	4,458
Option 3 – Add New Asset	-2,678	3,674
Option 4 – Flexible Solution followed by Add New Asset	-2,537	3,822

Table 8: CBA results summary

Options	Unit	2024	2025	2026	2027	2028	Total
Option 2 – Asset Replacement	£m	4.46	0	0	0	0	4.46
Option 3 – Add New Asset	£m	3.67	0	0	0	0	3.67
Option 4 – Flexible Solution	£m	0.003	0.040	0.105	3.674	0	3.82

Table 9: Annual Cost Apportionment

6.3 Options Summary

Option three is the lowest capital costs and may appear to be the attractive option. However, option 4 has the lowest NPV across a 45-year period and therefore is the most cost-effective solution for resolving the overloading issue identified. Therefore, option 4 is the preferred solution in this case.

6.4 Costing Approach

Our RIIO ED2 Business Plan costs are derived from our outturn RIIO ED1 expenditure. We have modified costs per activity, capturing and reporting those adjustments in our cost-book. By tying our costs back to reported, outturn, real life data this approach provides multiple data points on which both the Regulator and we can benchmark cost efficiency.

It provides a high level of cost confidence in our Business Plan cost forecast for RIIO ED2. Through our benchmarking analysis, we recognised that not all Non-Load related RIIO-ED1 actual unit costs sit within the upper quartile efficiency band. Where this is the case, we have applied a catch-up efficiency to those cost categories.

Further detail on our unit cost approach, cost efficiency and cost confidence for RIIO-ED2 can be found within our ***Cost Efficiency (Annex 15.1)***[5]. Following our draft Business Plan, we have continued to develop project scopes and costs, utilising valuable stakeholder feedback. We have included developments of our Commercial Strategy within the updated project scope and delivery strategy.

Unlike asset replacement, large load projects will include more unique and site-specific costs for example civils, waterway, road or rail crossings and local planning considerations. Through detailed bottom up project assessment, we have identified projects that are impacted by Regional and Site factors driving additional costs.

[5] Link to ***Cost Efficiency Annex 15.1***.

Category	Sub-category	Unit Cost (£k)	Unit	Asset Count	Predominant Costing Approach	Cost £k
Transformer	33/11kV transformers	[redacted]	#	1	ED1 6yr average actual unit rates	[redacted]
Switchgear	33kV CB (Air Insulated Busbars) (OD) (GM)	[redacted]	#	1	ED1 6yr average actual unit rates	[redacted]
Cable	33kV UG Cable (Non-Pressurised)	[redacted]	km	5	ED1 6yr average actual unit rates	[redacted]
Abnormal	London Region - Increased highway management	[redacted]	per site	1	ED1 6yr average actual unit rates	[redacted]
Abnormal	HDD – Thames crossing	[redacted]	Per site	1	ED1 6yr average actual unit rates	[redacted]
					Project Sub Total	**3,673.8**

Table 10: Cost and Volume Breakdown

The costs breakdown above is reflective of the cost of the physical asset and associated works only. The cost for the use of flexible services to defer the reinforcement until 2027 will be in addition of this. Based on the assessment of flexibility it is estimated that cost for procuring flexible services (availability and utilisation) will be £148.3k. This will bring the total project cost to £3,822k.

7 Deliverability and Risk

Between our draft and final Business Plans we have carried out a more detailed deliverability assessment of our overall plan as a package and its component investments. Using our draft Business Plan investment and phasing as a baseline we have followed our deliverability assessment methodology. We have assessed any potential delivery constraints to our plan based on:

- In-house workforce capacity and skills constraints based on our planned recruitment and training profile and planned sourcing mix as well as the efficiencies we have built into our Business Plan ***(detailed in our Workforce Resilience Strategy in (Annex 16.3)*** and ***Cost Efficiency (Annex 15.1)***
- Assessment of the specific lead and delivery timelines for the asset classes in our planned schemes
- We have evaluated our sourcing mix where there were known delivery constraints to assess opportunities to alleviate any constraints through outsourcing
- We have engaged our supply chain detailed in our ***Supply Chain Strategy (Annex 16.2)*** to explore how the supply chain could support us to efficiently deliver greater volumes of work and how we could implement a range of alternative contracting strategies to deliver this
- We have also engaged with the supply chain on the delivery of work volumes that sit within Uncertainty Mechanisms to ensure we have plans in place to deliver this work if and when the need arises
- Specific to load schemes: We have carried out flexibility assessments at all voltage levels in order to understand when we can defer reinforcement through paying for flexibility services, therefore ensuring our investment profile is deliverable and at the lowest cost to consumers ***see Flexibility within Load Related Plan Build and Strategy (Annex 10.1***)
- We have assessed the synergies between our planned load, non-load and environmental investments to most efficiently plan the scheduling of work and minimise disruption to consumers

- Based on our assessment of delivery constraints and potential solutions to resolve them, we have revised our investment phasing accordingly to ensure our Business Plan is deliverable, meets our consumers' needs and is most cost efficient for our consumers

The table below sets out the revised investment phasing based on the outcome of our deliverability assessment:

	2023/24	2024/25	2025/26	2026/27	2027/28
Revised Investment Phasing	£3.3k	£39.9k	£105k	£3,622k	0

Table 11 Investment phasing on deliverability assessment

This investment scheme is part of the wider load-related investment portfolio in RIIO-ED2. SSEN has developed a strategy to deliver a much larger volume of work in comparison with the level of investment in ED1. We have engaged with our supply chain to negotiate the most effective unit costs and we have taken measures to ensure we secure a future workforce with the right skills and competencies to deliver capital projects in ED2. In RIIO-ED1, SHEPD have delivered a number of 33kV and 11kV OHL projects using internal workforce. The experience and skills acquired from these projects lay the foundation for the delivery of the proposed option within this paper.

8 Conclusion

The purpose of this Engineering Justification Paper (EJP) has been to describe the overarching investment strategy that SSEN intends to take during RIIO ED2 for the load related investment of Egham Primary 33/11kV.

The thermal overloading of the 33kV circuits between Staines BSP and Egham Primary substation together with two 33/11kV transformer at Egham is triggered by three DFES scenarios namely System Transformation, Consumer Transformation and Leading the Way during the ED2 price control.

The following options were considered in the Ofgem's standard CBA and the CEM flexibility CBA

- Option 1: Do Minimum
- Option 2: Asset Replacement
- Option 3: Add New Asset
- Option 4: Flexible Solution followed by Add New Asset

Option 4: Flexible Solution, followed by Option 3: add new asset after 3 years is the preferred option due to its superior NPV value. The current Load Index (LI) for Egham is LI2 (90.3%) and it will be LI5 (116%) by the end of ED2 period (2027/28) without intervention. With the preferred reinforcement option, the LI will be LI1 (58%) with loading risk point decrement of 996,831 by the end of ED2 period.

Appendix 1. Relevant Policy, Standards, and Operational Restrictions

The policies, manuals and standards and operational restrictions relevant to the content of this paper.

Policy Number	Policy Name / Description
TG-NET-OHL-010	Load Ratings of Overhead Lines – Data Sheet
TG-NET-OHL-012	Short Circuit Ratings of Overhead Lines – Data Sheet
TG-NET-OHL-104	Electrical Constants for Overhead Lines- Data Sheet
TG-NET-CAB-009	Load Ratings of LV to 33kV Underground Cables – Design Data
TG-NET-CAB-010	Electrical Constants for LV to 33 kV Underground Cables- Data Sheet
TG-NET-CAB-011	Short Circuit Ratings of 6.6kV to 33kV Underground Cables - Design Data

Table 12 Relevant documents

Appendix 2. Network Analysis

Voltage Level Assessment

	SYSTEM VOLTAGE LEVELS						
Year	**Season**	**Staines 33kV voltage (pu)**	**Demand**	**Generation**	**Study Scenario**	**Egham 11kV voltage(pu)**	**Busbar Name**
	[-]	[p.u.]	[MVA]	[MVA]	[-]	[p.u.]	[-]
2024	Winter maximum	1.026	28.2 MVA	0	Intact	1.033	EGHA-E
2024	Winter maximum	1.017	28.2 MVA	0	Fault on Egham T1	0.935	EGHA-E
	The Voltage levels are in the limit of ± 10% on 132KV. ± 6% on 33KV under intact condition.						

Table 13: Voltage Level Assessment Results

Fault Level Assessment

Bus Number	Bus Name	Nominal Voltage (kV)	Pre-fault Voltage (p.u)	X/R ratio	Ik"- Initial Sym. (kA)	Ip- Peak Make (kA)	RMS Sym. Break (kA)	DC Component (kA)	RMS Asym. Break (kA)	Circuit Breaker Break Rating	Circuit Breaker Make Rating	Circuit Breaker Fault Level Index
3 Phase Fault Level Results at the End of ED2 2027/2028												
23730	STAI-C1	33.	1.03	16.1	16.8	43.9	15.4	13.03	20.17	31.5	78.8	FLI1
86515	EGHA-E	11.	1.029	8.2	11.31	27.41	10.23	3.59	10.84	20	50	FLI1
Single Phase to Ground Fault Level Results at the End of ED2 2027/2028												
23730	STAI-C1	33.	1.03	0.5	1.55	2.57	1.55	1.14	1.93	31.5	78.8	FLI1
86515	EGHA-E	11.	1.029	0.1	1.23	1.77	1.23	0	1.23	20.0	50	FLI1

Table 14: Fault Level Assessment Results

Appendix 3. Whole Systems Consideration

In augmenting our decision-making processes to consider Whole System solutions, we have introduced an assessment to identify where a Whole Systems CBA would be a useful decision-making tool for ED2 load and non-load schemes. While our work with the ENA to undertake Whole Systems CBAs is ongoing, we have introduced the 'Whole Systems CBA test' to identify where a scheme may be suitable for a Whole Systems CBA to be conducted. Where a Whole Systems CBA is determined to be a useful decision-making tool, these would be conducted in addition to the standard Ofgem CBA and/or SSEN's flexibility CBA. We have introduced this test in line with Ofgem's expectations for "proportionality when submitting a Whole System CBA. For example, smaller or simple projects following the standard CBA template, whereas larger or more complex projects requiring bespoke analytical approaches" (Ofgem BPG, section 4.28, p.34).

The 'Whole Systems CBA test' involves assessing each investment scheme of over £2m (the threshold to develop an EJP for load and non-load investments) against 5 tests. These 5 tests help determine whether a Whole Systems CBA is a useful decision-making tool based on the characteristics of the scheme, including whether it will have wider cross sector or societal impacts.

Details on each of the tests are provided in case study 6 in ***Whole Systems (Annex 12.1)***. Tests 1-3 are aligned with the ENA's guidance for Whole System CBA tests. We have added Tests 4 and 5 to clarify whether a Whole Systems CBA is required based on the materiality / proportionality of the investment (Test 4) and whether a flexibility CBA only is sufficient (Test 5). Table 15 below outlines our Whole Systems CBA test for 132 kV Reinforcements at Fawley North BSP.

Scheme	**Test 1: Are there Whole Systems interactions, or is there potential for it?**	**Test 2: Could a Whole Systems CBA drive you to make a different decision?**	**Test 3: Is a Whole Systems CBA reasonable?**	**Test 4 - Is the project valued at over £2m?**	**Test 5 - Is the investment plan related to procuring flexible solutions only?**
Egham primary	No – We consider there to be limited potential for Whole Systems interactions with third parties to deliver this investment programme, and accordingly we do not consider there to be potential for Whole Systems solution(s).	No – As noted under Test 1 we do not consider there to be potential for Whole Systems solution(s) in this case.	No – As noted under Test 1 we do not consider there to be potential for Whole Systems solution(s) in this case.	No	No

Table 15: Whole Systems CBA test for Egham primary

As the result of tests 1, 2 and 3 above is “No”, a Whole Systems CBA is not required for this investment. It is not expected to have any wider Whole System interactions or potential Whole Systems solutions.