RIIO-ED2 Engineering Justification Paper (EJP)

Upton 132kV System Reinforcement

Investment Reference No: 66/SEPD/LRE/Upton

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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 in the Upton 132kV network will deliver P2/7 compliance for an expenditure of £10.446m during RIIO-ED2.

The primary investment driver for this scheme is load related P2/7 compliance issue within the Upton 132kV network. The P2/7 compliance issues are apparent under Distribution Future Energy Scenario (DFES) Consumer Transformation & Leading the way scenarios from 2024 and Steady Progression & System Transformation from 2026. The P2/7 compliance issue therefore requires investment in ED2 due to forecast demand growth.

The EJP considers a range of options to address the P2/7 compliance issue, 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 (£m), is option 5 which will use flexible services followed by conventional reinforcement.

Options	Net Present Value (NPV) After 45 Years (£k)	Investment (£k)
Option 2 – Addition of a 132kV switching station	-8,587	10,389
Option 5 – Flexible Solution	-8,325	10,446

Table 1: Option Summary

Following the optioneering and detailed analysis, as set out in this paper, the proposed scope of works for Option 5 is:

Asset	Volume	Costs
Land for new 132 kV switching station	1	[redacted]
New 132 kV outdoor double busbar	1	[redacted]
132kV CB (Air Insulated Busbars)(OD) (GM)	8	[redacted]
132kV UG Cable (Non Pressurised)	6	[redacted]
132kV CB (Gas Insulated Busbars)(ID) (GM)	1	[redacted]
Cable sealing ends and terminal structure	1	[redacted]
HDD - M25 crossing	1	[redacted]
Total		**£10,389.4k**

Table 2 Investment Summary

The costs listed above reflect the costs to replace the existing assets. 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 £56.2k bringing the total project cost to £10,446k.

This scheme delivers the following outputs and benefits:

- The uplift in network capacity from 124MVA to 248MVA to meet the needs of our customers.

- A secondary benefit of increasing the SCO capacity to 99MVA
- A reduction of the load index for the substation group from LI5 with no network reinforcement, by the end of RIIO ED2 to LI1
- Facilitates the efficient, economic, and co-ordinated development of our Distribution Network for Net Zero.

The cost to deliver the preferred solution is £10.45m and the works are planned to be completed in 2025. This EJP investment sits within our Net Zero Totex ask.

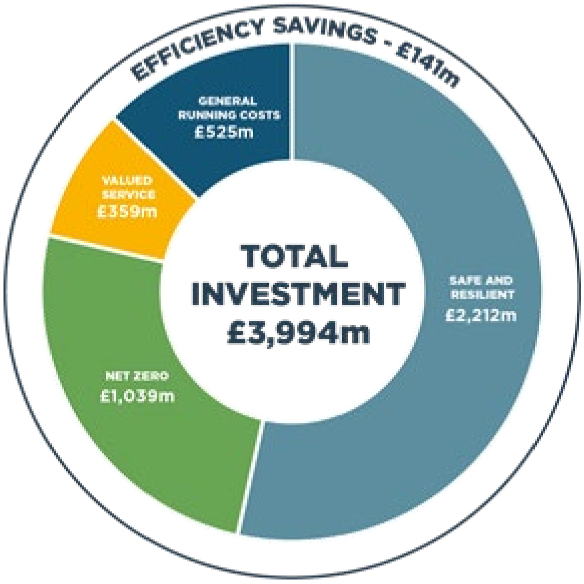


Figure 1: SSEN total investment cost within RIIO ED2

2 Investment Summary Table

Table 3 provides a high level summary of the key information relevant to this Engineering Justification Paper (EJP) which discusses the investment proposals for Upton 132 kV network.

Engineering Justification Paper Investment Summary				
Name of Scheme	Upton 132 kV System Reinforcement			
Primary Investment Driver	Load – P2 compliance (thermal overloading)			
Scheme reference/ mechanism or category	66/SEPD/LRE/Upton			
Output reference/type	132kV Circuits			
Cost	£10.45m			
Delivery Year	2025/2026			
Reporting Table	CV1: Primary Reinforcement			
Outputs in RIIO ED1 Business Plan?	No			
Spend Apportionment	(£m)	**ED1**	**ED2**	**ED3+**
	SEPD	-	£10.45m	-

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 within the Upton 132kV network 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 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.

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

4 Background Information and Analysis

4.1 Existing Network Arrangement

Upton and Chalvey BSPs are located within the Buckingham council area within the SEPD licence area. Iver substation is a 275/132 kV GSP with its 132 kV busbar run solid, and Main and Reserve sections thereof coupled via two 132 kV bus-couplers. The busbars are supplied by four 275/132 kV 240 MVA SGTs with a further SGT run on hot-standby (with auto-close scheme to maintain network security).

National Grid has initiated a project to replace the existing SGTs at Iver GSP with larger capacity units (instead of adding additional units), following SSEN acceptance of a modification application offer to facilitate accepted new connection load growth in this GSP's supply area. Completion of the project is expected for 2026/27.

As shown in Figure 2, Upton BSP is supplied from a double tee off on the two Iver – Chalvey 132 kV circuits. Thus, the section of line between Iver and the tee carries the load for both Upton and Chalvey BSPs under normal operating conditions.

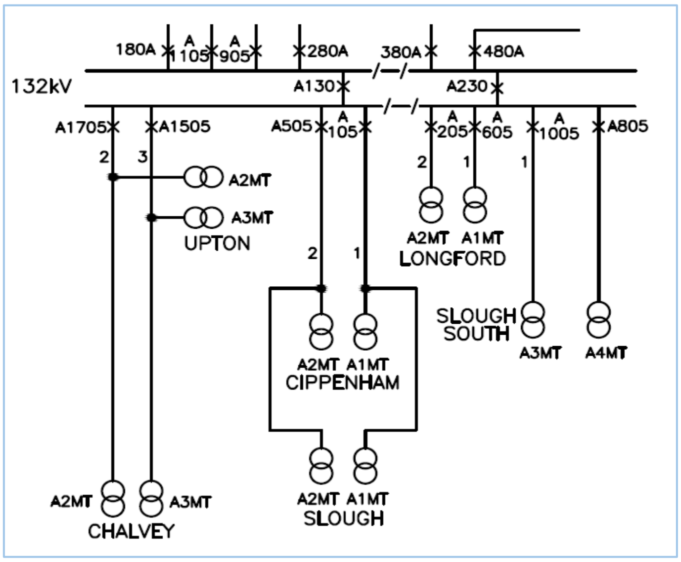


Figure 2: Operational Diagram showing 132 kV network downstream of Iver 275/132kV substation

4.2 Local Energy Plan

In 2019, Buckinghamshire council declared a climate emergency and acknowledged the need for Climate Change Strategy. Following this, the council has agreed to:

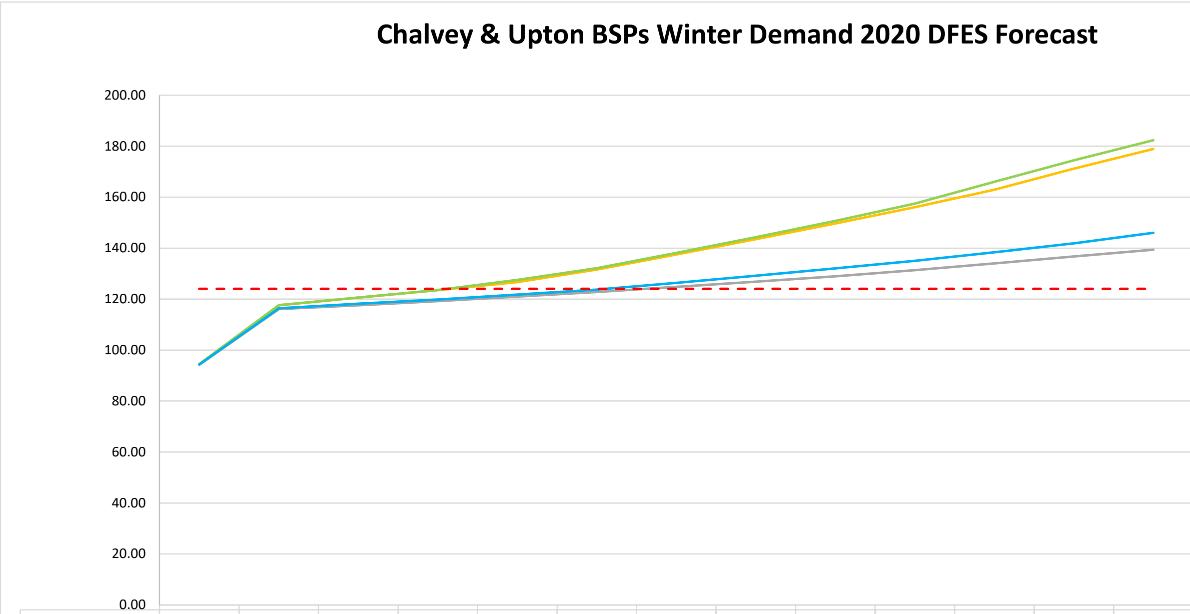
- Improving the energy efficiency of new and existing commercial buildings
- Maximising the potential of future housing growth to deliver clean growth
- Establishing a 'Living Lab' to invest in energy innovation to stimulate new business models
- Promoting the development of innovative, local, integrated, clean energy systems
- Agree that the new Buckinghamshire Council should consider addressing climate change as a key issue.
- Facilitating the development of Heat Networks
- Accelerating the rollout of Low Carbon Vehicle (LCV) Charging Infrastructure

- Encouraging the development of Community Energy Solutions

4.3 Demand and Generation Forecasts

It should be noted that outside of the DFES forecasts, two large connection schemes, 13.5MVA battery connection and 6.5MVA of domestic load (HV connected), are expected to take a diversified total of 20 MVA load from Chalvey BSP, as a step increase from 2021/22 onwards. This increase has therefore been added to each scenario. Since no information about the daily or seasonal profile of this load is known, it has been assumed to exist throughout the year.

Figure 3 shows the aggregated winter demand projections in MVA of the Chalvey and Upton BSPs together, being fed from Iver GSP, via the two Iver-Chalvey tee-Upton 132 kV circuits.

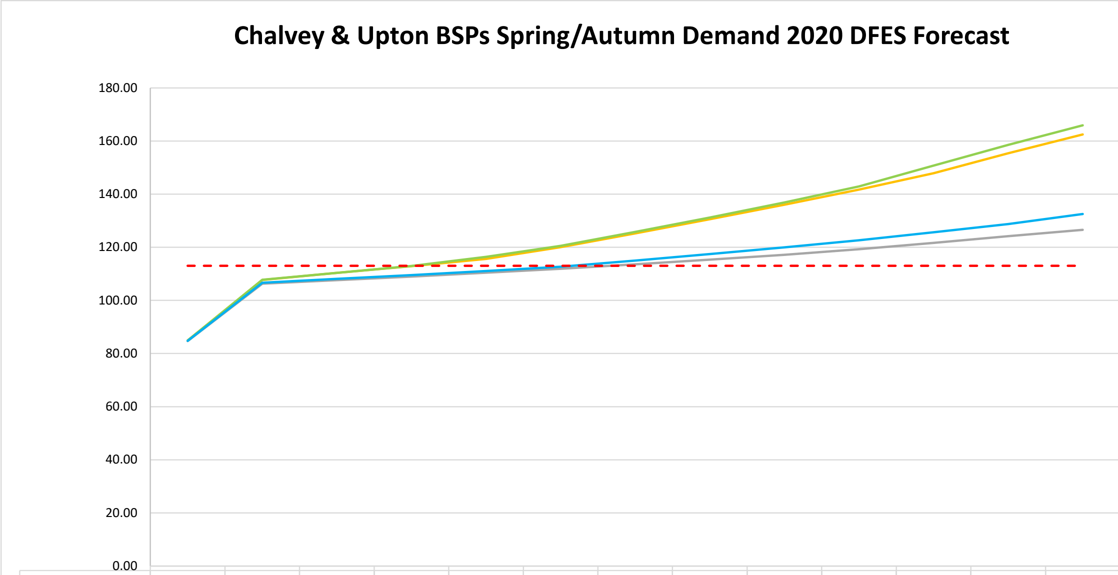


SP	94.27	116.07	117.60	119.21	121.01	122.80	124.77	126.80	128.92	131.35	134.03	136.77	139.41
CT	94.50	117.59	120.61	123.47	126.71	131.62	137.52	143.54	149.67	156.06	162.93	171.15	178.87
LW	94.49	117.65	120.61	123.58	127.51	132.16	138.15	144.28	150.70	157.46	166.03	174.44	182.31
ST	94.34	116.41	118.19	119.86	121.76	123.71	126.39	129.15	132.03	135.04	138.41	141.91	146.01
Firm Capacity	124	124	124	124	124	124	124	124	124	124	124	124	124

Figure 3: Chalvey and Upton BSP Winter Demand 2020 DFES Forecast including additional connection schemes

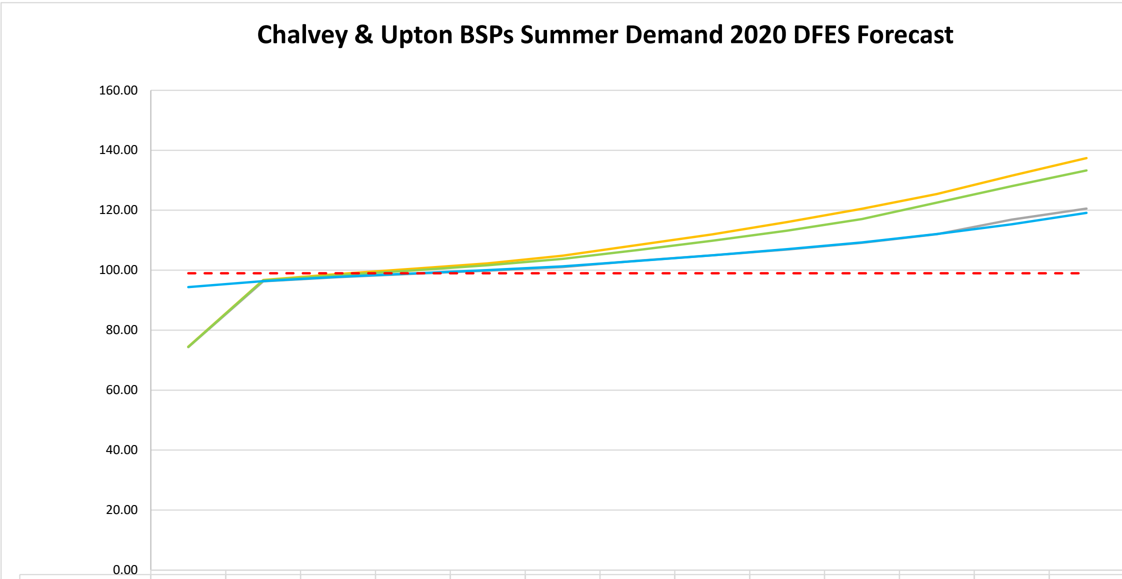
The N-1 Firm Capacity is limited by the section of 132 kV lines between Iver and the tee-point. It can clearly be seen that from 2024 onwards, the *Consumer Transformation* and *Leading the Way* scenario forecasts exceed the firm capacity of the circuits. The other two scenarios follow in 2026.

Further investigation shows that the circuits concerned have significantly reduced Spring/Autumn and Summer ratings (113 MVA and 99 MVA, respectively), and as such, the data for the combined Upton and Chalvey BSP loads were investigated against those limitations, as shown in Figure 4 and Figure 5.



SP	84.67	106.32	107.62	108.96	110.41	111.93	113.62	115.36	117.18	119.31	121.69	124.15	126.60
CT	84.90	107.72	110.38	112.87	115.65	120.02	125.24	130.58	136.03	141.73	147.89	155.41	162.52
LW	84.88	107.76	110.37	112.96	116.37	120.51	125.79	131.21	136.92	142.93	150.77	158.58	165.92
ST	84.73	106.63	108.16	109.54	111.08	112.68	115.00	117.44	119.98	122.64	125.64	128.76	132.57
Firm Capacity	113	113	113	113	113	113	113	113	113	113	113	113	113

Figure 4: Chalvey and Upton BSP Spring / Autumn Demand 2020 DFES Forecast including additional connection schemes



SP	74.35	96.29	97.66	98.78	99.86	101.06	103.18	104.94	106.92	109.16	112.03	116.90	120.56
CT	74.45	96.75	98.72	100.47	102.26	104.84	108.41	111.92	116.07	120.50	125.41	131.51	137.39
LW	74.44	96.62	98.34	99.94	101.68	103.78	106.71	109.85	113.20	117.09	122.52	128.06	133.26
ST	94.37	96.35	97.78	98.89	100.02	101.28	103.06	104.96	107.05	109.29	112.05	115.30	119.10
Firm Capacity	99	99	99	99	99	99	99	99	99	99	99	99	99

Figure 5: Chalvey and Upton BSP Summer Demand 2020 DFES Forecast including additional connection schemes

For Spring/Autumn the firm capacity is shown to be exceeded from 2023 for the *Leading the Way* scenario and 2024 for the *Consumer Transformation* scenario. For Summer, the firm capacity overload is forecast to occur in 2023 for both the *Leading the Way* and *Consumer Transformation* scenarios and for all scenarios by 2024.

It is seen in Figure 6 that peak demand is expected to increase within the Upton/Chalvey demand group by approximately 29MVA from 2019/20 to 2027/28 when following the baseline CT scenario. The projected primary demand by the end of ED2 is split as shown below by demand type. The chart shows the largest impact on demand in the area is from domestic and non-domestic load each equating to 11.4% and 8.9% of the overall projected demand increase respectively.

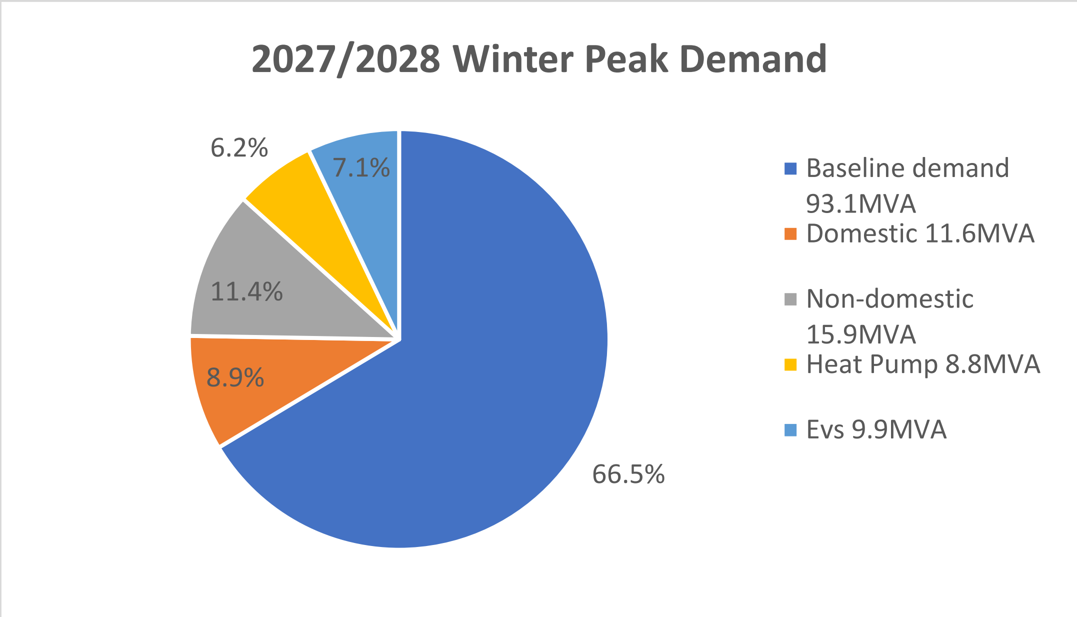


Figure 6: Chalvey and Upton BSP Winter Demand Forecast

4.4 Existing Asset Condition

The methodology for assessing the Health Index (HI) scoring has been considered for all relevant components on the network under study.

Component Assessed	HI
Iver - Chalvey - Upton OHL Conductor	HI 2
Iver - Chalvey – Upton Tower structures (12)	HI 3
132 kV breakers at Iver	HI 1
Upton BSP Transformers	HI 1

Table 4: Present Health Index for 132kV Iver/Chalvey-Upton hardware

According to these results, it can be noted that the existing 132 kV circuits are in good health, with some recommended further assessment and monitoring of the tower structures where the circuits run overhead. A risk assessment on these towers resulted in a decision not to replace them, as rapid further deterioration is not expected.

All things considered, the Asset Condition Assessment points to good justification for continuing to make use of the existing infrastructure, with substantial motivation for adding additional assets to improve the capabilities under FCO conditions, whether those are planned or unplanned.

4.5 Thermal Analysis

Based on the foregoing assessment of presently installed equipment, existing and forecast loading, and condition HI data, the main driver for required network investment is insufficent firm thermal capacity on the Iver-Chalvey 132 kV circuits, specifically on the 6 km section of each circuit, between Iver GSP and the tee-point to Upton BSP.

Power System studies to assess contingency capabilities to meet Group Demand (GD) and fault rating adequacy of components are documented in table 5 below.

The network analysis has been performed using *Consumer Transformation* scenario loading, as this is assumed to hold best balance between a conservative network assessment and a realistic loading situation.

The Group Demand (GD) for the Iver-Chalvey/Upton 132 kV circuits during RIIO-ED2 puts the site in Class D (60-300 MW), requiring restoration of full GD minus 20 MW immediately following a First Circuit Outage (FCO).

The forecast 2027/28 Winter GD simulations show the total load to be 150.4 MVA (including losses). The load index for the Upton/Chalvey demand group is expected to be LI4 at the beginning of RIIO ED2 and is expected to increase to LI5 by the end of the RIIO ED2 price control period. As previously stated, the FCO capacity for the lines in Winter is 124 MVA. Similarly, the 2027/28 Spring/Autumn GD is forecast to be 136 MVA , and network analysis shows the total load to be 138 MVA against a rating of 113 MVA. Finally, the Summer GD forecast is 116 MVA, against a rating of 99 MVA. By 2027/28, the FCO capacity for the lines is exceeded in all seasons, hence there is a clear P2/7 non-compliance issue for FCO conditions.

Demand Group	Season	Group Class	Contingency	Loaded Circuit / Transformer	FCO Demand to be Met	FCO Available Capacity
Iver – Chalvey/Upton 132 kV circuit	Winter	D	Iver / Chalvey / Upton tee 132 kV circuit	Remaining Iver / Chalvey / Upton tee 132 kV circuit	150.4 MVA minus 20 MW ≅ 130 MVA	124 MVA
Iver – Chalvey/Upton 132 kV circuit	Spring/ Autumn	D	Iver / Chalvey / Upton tee 132 kV circuit	Remaining Iver / Chalvey / Upton tee132 kV circuit	138 MVA minus 20 MW ≅ 118 MVA	113 MVA
Iver – Chalvey/Upton 132 kV circuit	Summer	D	Iver / Chalvey / Upton tee132 kV circuit	Remaining Iver / Chalvey / Upton tee132 kV circuit	123 MVA minus 20 MW ≅ 103 MVA	99 MVA

Table 5: First Circuit Outage (FCO) Analysis (2027) – Base Case

Reinforcement of this network is required due to non compliance with P2/7 under FCO conditions.

4.6 Voltage Level Assessment

The voltage level at the 132kV and 33kV bus bars were also assessed. The analysis showed that reinforcement is not required based on voltage as voltage compliance is met.

4.7 Fault Level Assessment

The fault levels at the 33kV bus bars at Upton and Chalvey BSPs were assessed for both three phase and single phase to ground faults. The fault level study showed that there are no fault level issues at the Upton and Chalvey 33kV busbars during the RIIO-ED2 price control period.

4.8 Network Analysis

The system analysis of the Upton 132kV network has shown that during the RIIO ED2 price control period the network will become overloaded under FCO conditions due to increase in demand. As a result, network intervention is required to mitigate this issue. No voltage of fault level issues are expected to arise during the RIIO ED2 price control period.

5 Summary of Options Considered

This section of the report sets out the investment options that were considered when resolving overload issues within the Upton 132kV network. As described below, a holistic approach is taken to ensure investment options represent 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

The table below provides a high-level summary of the five 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
Option 1 – Do Minimum	Since Chalvey and Cippenham, as well as Chalvey and Slough have 33 kV interconnection, load could be transferred away from Chalvey to reduce the thermal loading on the circuits from Iver.	• Minor investment cost	• The use of the 33kV interconnectors will increase the Group demand beyond 300MVA requiring reinforcement of the 132kV network	Not Progressed to CBA
Option 2 – Addition of a 132kV	Construct a new 132 kV switching station at the tee to Upton, on the	• Adds normal transfer capacity and FCO capacity to the most heavily loaded section	• Requires cabling for third circuit to avoid the need for widening existing servitude.	Progressed to CBA

switching station	Iver - Chalvey 132 kV lines. Construct a third, 6 km 132 kV circuit from Iver to the new switching station.	of the Iver – Chalvey circuits. • Creates SCO capacity where there previously was none. • Creates operational flexibility on the circuits. • Lowest NPV. • Would allow for capacity increase at Upton BSP when required, by building a third feeder from the Switching station and installing a third transformer.	• Dependent on upgrade of Iver 132 kV substation (space for new breaker)	
Option 3 – Replacement of existing 132kV circuit	Replace 6 km section of line with larger conductor	• No additional breaker required at Iver GSP.	• Doesn't improve operational flexibility. • Constructability would be a challenge, due to lack of N-1 capability on the existing circuits.	Not progressed to CBA
Option 4 – Addition of a third 132kV circuit and third 132kV transformer	Build a third circuit between Iver and Upton, with a third transformer at Upton BSP.	• Increases capacity and redundancy at Upton BSP.	• Requires cabling for third circuit to avoid the need for widening existing servitude (longer route than Option 2) • Dependent on upgrade of Iver 132 kV substation (space for new breaker) • FCO of one of the existing Iver/Chalvey/Upton tee circuits still results in overloading of the other one, by a small percentage, during Winter.	Not progressed to CBA
Option 5 – Flexible Solution followed by conventional reinforcement	Flexible service contracts to reduce peak demand and defer capital investment	• Defers investment for one year for three scenarios	• Does not defer investment for CT scenario	Progressed to CBA

Table 6: Summary of Investment Options

5.3 Detailed Option Analysis

5.3.1 Option 1: Do Minimum

Estimated Cost: £0k

Since Chalvey and Cippenham, as well as Chalvey and Slough, have 33 kV interconnectors between them, load could be transferred away from Chalvey to reduce the thermal loading on the circuits from Iver under N-1. Each of these interconnection circuits are rated at 104.4MVA and 19.5MVA respectively.

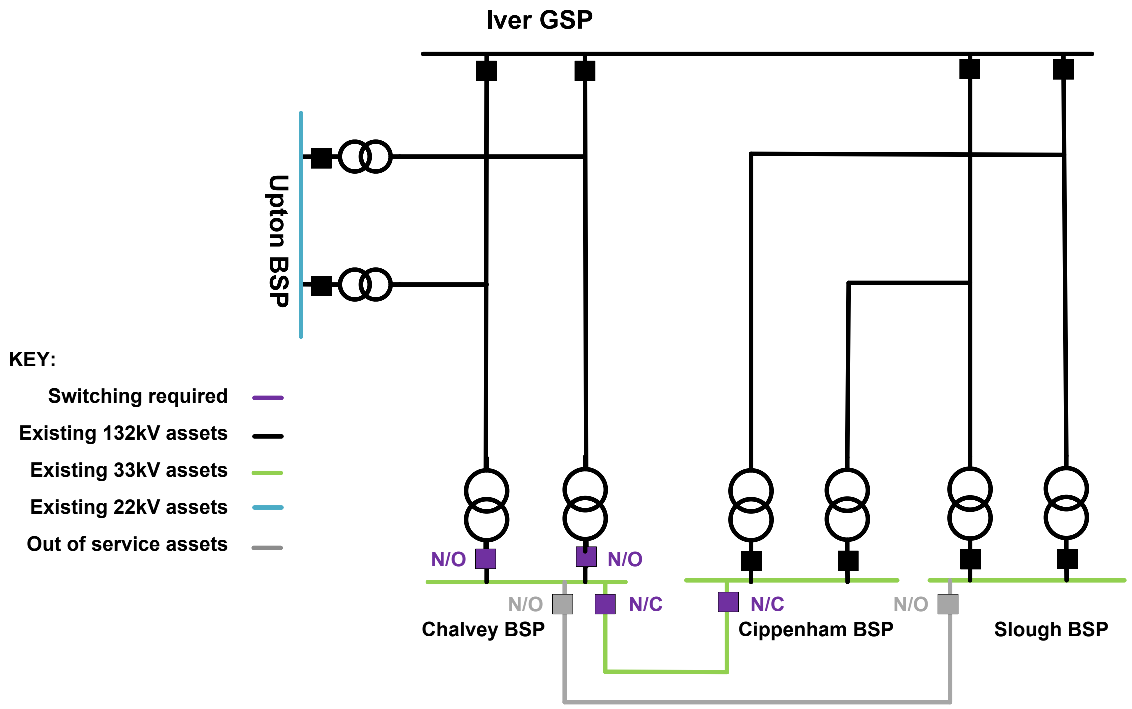


Figure 7: Option 1 Proposed Solution Schematic

In the case of N-1, the 33kV interconnections between Chalvey/Upton/Cippenham/Slough (and Slough South) result in a rise in the Group demand in excess of 300MVA which requires further reinforcement works to be undertaken (further 132kV cable reinforcement, and new transformer circuits to additional BSPs within the group) dependent upon the N-1 Fault location. Costs incurred in laying a minimum of 12km of cable to install a new 132/33kV transformer at Slough meant this would not be minimum scheme.

As this option will not fully resolve the overloading and P2/7 non-compliance without further network reinforcement, this option has been rejected and not taken forward into the Ofgem CBA assessment.

5.3.2 Option 2: Add new assets – 132 kV switching station and 3rd 132 kV circuit

Estimated Cost: £10,390k

For this option it is proposed to build a new 132 kV switching station and a third, approximately 6 km 132 kV circuit from Iver to the switching station, to relieve the FCO overloading issue. This option would require that new land to be found and secured for a new 132 kV switching station. It is proposed that the third circuit be cabled so as to avoid the need to widen the existing servitude in a space-constrained environment. A schematic of the proposed solution can be viewed in the figure below.

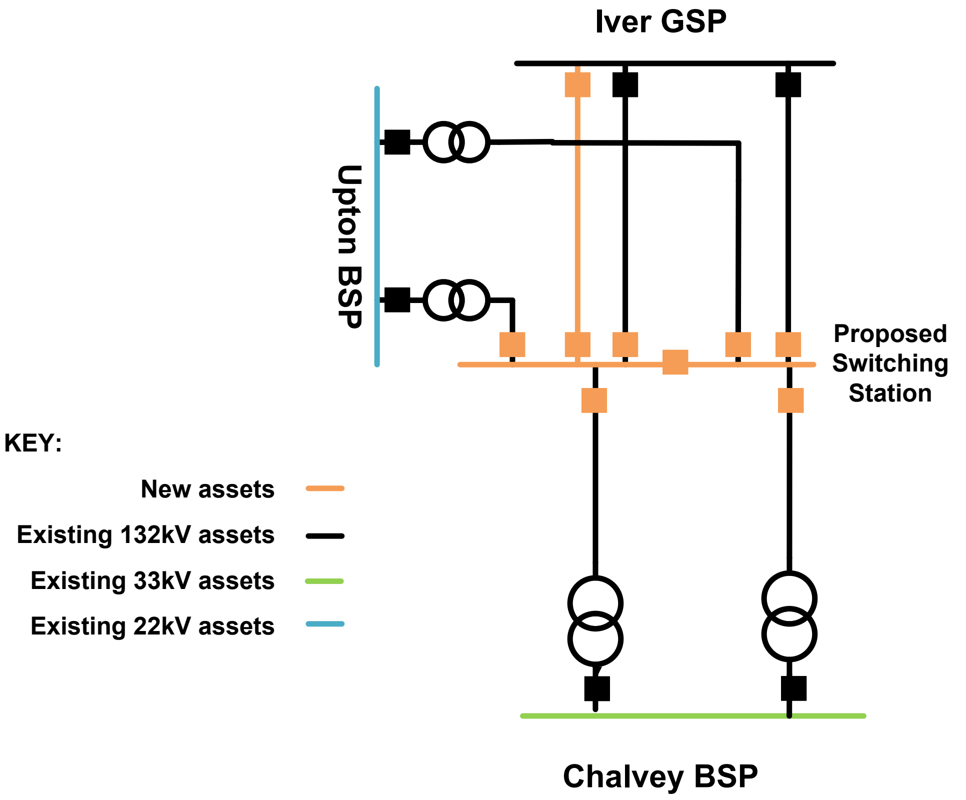


Figure 8: Option 2 Proposed Solution Schematic

The proposed solution will be achieved by:

- Establishing a new 132 kV switching station comprising a new 13 2kV outdoor busbar and 8 x 132 kV outdoor circuit breakers
- Trenching approximately 6 km of underground 132 kV cable to run between Iver and the new switching station
- Installing 132 kV cable sealing ends and terminal structure at Iver GSP
- Installing 1 x 132 kV gas insulated indoor circuit breaker at the new Iver 132 kV indoor substation
- Unbanking the Upton and Chalvey BSP substations from the 132 kV circuits
- Connecting the existing 132 kV circuits from Iver to the new 132 kV switching station
- Connecting the 132kV circuits to the new switching station

With this configuration, the FCO capacity of the circuits between Iver and the new switching station will double from 124 MVA, 113 MVA and 99 MVA to 248 MVA, 226 MVA and 198 MVA (in Winter, Spring/Autumn and Summer, respectively) which will ensure compliance with P2/7. This new arrangement shall release 124 MVA of winter load capacity. An additional benefit of this solution is that the SCO capacity will also increase from 0 MVA to at least 99 MVA. This solution will also result in the load index reducing from LI5 by the end of RIIO ED2, if no intervention is carried out, to LI1. An Additional benefit of this scheme is that the proposed solution will provide future flexibility to uncouple Cippenham from the existing Slough/Cippenham meshed network.

Ofgem's RIIO-ED2 standard CBA template was used to assess costs and benefits of the conventional Options 1-4. 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 2 came out as the preferred conventional investment option which is used to feed into the Common Evaluation Methodology (CEM) [2] Flexibility CBA to determine if there are economic benefits in deferring this capital investment.

5.3.3 Option 3: Replace Assets

Estimated Cost: £13,460k

This option would require that the existing 132 kV circuits be replaced with higher capacity cables than the existing overhead conductors. Approximately 12 km of underground 132 kV cable will need to be installed and it is required that these cables should have a minimum winter rating in excess of 130 MVA each, in order to meet the FCO conditions of P2/7. A schematic of this proposed solution is shown in Figure 10 below.

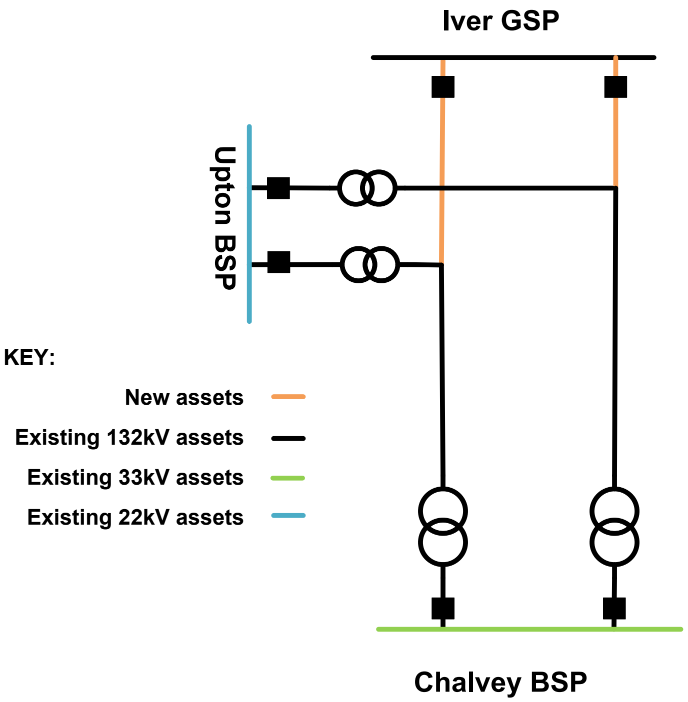


Figure 9: Option 3 Proposed Solution Schematic

For the purposes of simulation, a 630 mm^2 cable was selected. With this configuration, the FCO capacity of the circuits between Iver and the new switching station will increase from 124 MVA, 113 MVA and 99 MVA to 149 MVA, 129 MVA and 129 MVA (in Winter, Spring/Autumn and Summer, respectively) which enables compliance with P2/7. This new arrangement shall release 25 MVA of winter load capacity. However, no SCO capacity will be made available. This option will result in the load index reducing from LI5 by the end of RIIO ED2, if not intervention is carried out, to LI4. Therefore this option is rejected and not progressed to CBA.

5.3.4 Option 4: Add New Assets – 3rd circuit

Estimated Cost: £11,140k

This option would require an additional 132 kV circuit from Iver GSP all the way to Upton BSP, and a third 132/22 kV transformer to be installed at Upton BSP substation. A schematic of this proposed solution is shown in the figure below.

This solution would require:

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

- Approximately 7.6 km of underground 132 kV cable
- New 132/22 kV 60 MVA Transformer at Upton BSP
- 132 kV cable sealing ends and terminal structure at Iver GSP
- 1 x 132 kV gas insulated indoor circuit breaker at the new Iver 132 kV indoor substation

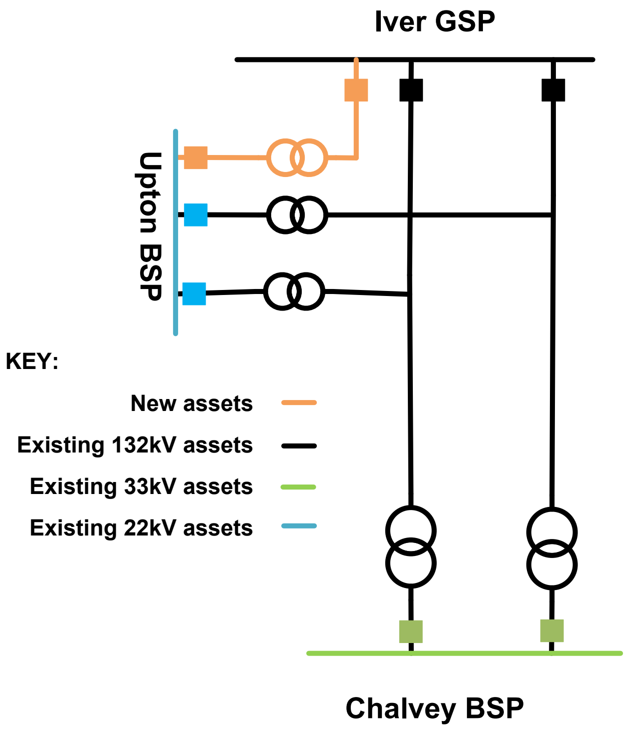


Figure 10: Option 4 Proposed Solution Schematic

For the purposes of simulation, a 630 mm^2 cable was selected, and a third transformer identical to the existing two (78 MVA Winter rating). With this configuration, the FCO capacity of the circuits between Iver and the tee-point to Upton will experience a small increase from 124 MVA, 113 MVA and 99 MVA to 141 MVA, 128 MVA and 113 MVA (in Winter, Spring/Autumn and Summer, respectively) which enables compliance with P2/7, by a small margin. This new arrangement shall release 17 MVA of winter load capacity. This solution would result in the load index of this substation reducing from LI5 by the end of RIIO ED2, if not intervention is carried out, to LI4.

Although no immediate FCO capacity is created by this solution, with 33 kV switching, the loss of both existing Iver/Chalvey/Upton tee 132 kV circuits could be mitigated by switching the Chalvey load to Cippenham via the 33 kV connector and supplying the full Upton load off the proposed Iver-Upton 132 kV circuit. No benefit would come from pre-emptive switching, as this would leave the Cippenham/Slough circuits without FCO capabilities. This complicated arrangement is therefore not considered to add much favour to this option.

5.3.5 Option 5: Flexible solution

Estimated Cost: £10,446k

An alternative to conventional reinforcement is through the use of flexible service. 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.

The baseline reinforcement cost used as an input into the CEM framework is the costs associated with Option 2 – Addition of 132 kV switching station and a third 132kV circuit, equating to £10.4m. Figure 11 and Figure 12 show a typical load profile (in MW) of a winter day and Spring/Autumn day from 2020 to 2032. For the *Consumer Transformation* scenario, the peak demand exceeds the FCO rating for approximately 1 hours per day in 2024 and for 7.5 hours per day in 2028. Flexibility services in the form of increasing generation export or decreasing demand import could be used to reduce the peak.

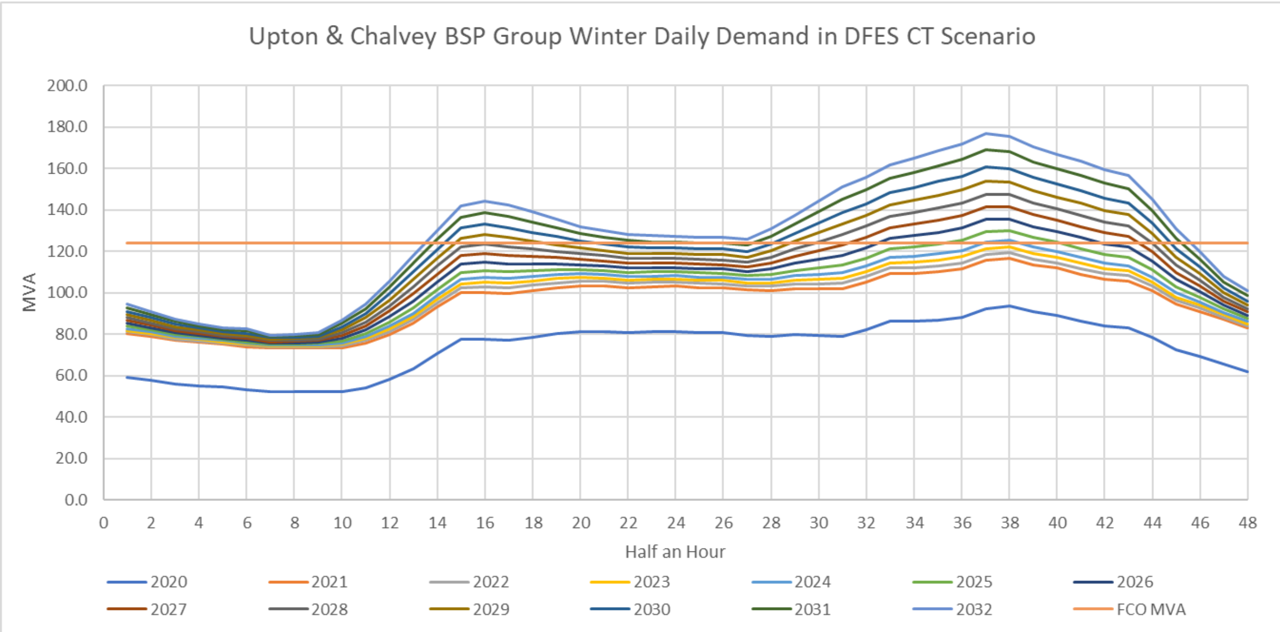
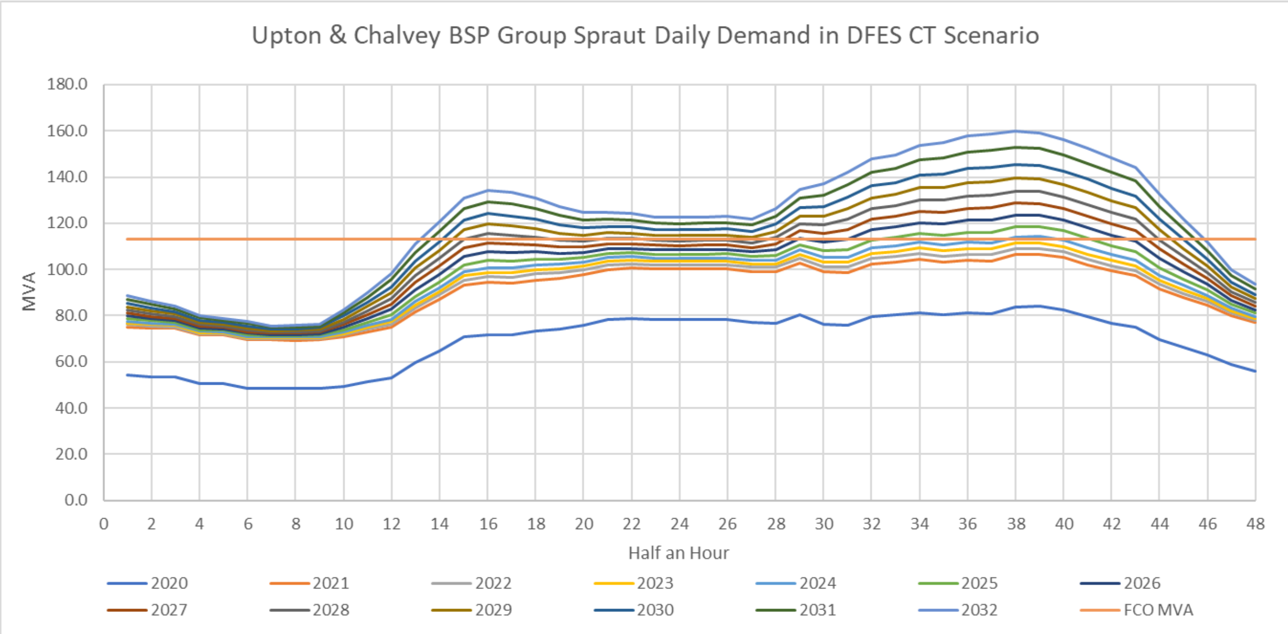


Figure 11: Upton/Chalvey Winter Daily Demand

In Spring / Autumn, for the *Consumer Transformation* scenario, the peak demand exceeds the FCO rating for approximately 1 hours in 2024 and for 11 hours in 2028.



It should be noted that all demand profiles modelled include a block load of 20 MVA with a flat profile, as described in earlier sections of this report. As such, the true demand profile is likely to be somewhat more varied.

The MW exceedance, the daily and annual overload hours (7) and the 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	0.0	0.0	0.0	1.0	3.8	5.3	7.0
Days/yr required	0.0	0.0	0.0	0.0	192.0	192.0	256.0	256.0
Utilisation (MWh)	0.0	0.0	0.0	0.0	124.8	2079	6106	12454

Table 7: Estimated dispatch requirements for flexibility solution

The CEM CBA model suggests that under the Consumer Transformation and Leading the Way DFES 2020 scenarios, flexibility can be used to defer conventional network reinforcement for one year until 2026.

Cumulative benefit of deferral (excluding benefit from further deferral, but including multi-year discount)		**Defer by 1 year(s) to 2026**	**Defer by 2 year(s) to 2027**	**Defer by 3 year(s) to 2028**
[1] under Consumer Transformation	*£0*	£228,290	-£390,776	-£2,663,645
[2] under Leading the Way	*£0*	£167,476	-£657,437	-£3,025,970
[3] under Steady Progression	*£0*	£283,576	£556,239	£818,453
[4] under System Transformation	*£0*	£283,576	£556,239	£774,607

Figure 13: Optimal deferral graph from CEM CBA

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 1 year until 2025/2026. 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 be a further market test for full Flexibility, accelerating the Conventional solution or a Hybrid Scheme.

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

6 Cost Benefit Analysis (CBA)

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 our ***Cost Benefit Analysis Process (Annex 15.8)***.

6.2 CBA Results

Table 8 below summarises the CBA outcome for all the options considered to resolve the thermal constraints within the Upton 132kV network. The CBA results show that Option 5 is the most cost effective solution as the NPV across a 45 year period is the smallest.

Options	NPV After 45 Years (£k)	Total Investment cost (£k)
Option 2 – Addition of a 132kV switching station	-8,587	10,389
Option 5 – Flexible Solution	-8,325	10,446

Table 8: CBA results summary

Options	Unit	2023/24	2024/25	2025/26	2026/27	2027/28	Total
Option 2 – Addition of a 132kV switching station	£m	0	10.39	0	0	0	10.39
Option 5 – Flexible Solution	£m	0	0.056	10.39	0	0	10.446

Table 9: Summary of investment costs

6.3 Option Summary

The results of the OFGEM CBA show that the preferred option is Option 5: Flexible solution. This option has the lowest NPV value across a 45 year period and therefore the most cost effective solution compared to the other solutions presented in this EJP.

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)***[3]. 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.

[3] Link to ***Cost Efficiency (Annex 15.1)***.

Category	Sub-category	Unit Cost (£k)	Unit	Asset Count	Predominant Costing Approach	Cost £k
Substation	New 132 kV outdoor double busbar	[redacted]	#	1	ED1 6yr average actual unit rates	[redacted]
Switchgear	132kV CB (Air Insulated Busbars)(OD) (GM)	[redacted]	#	8	ED1 6yr average actual unit rates	[redacted]
Cable	132kV UG Cable (Non Pressurised)	[redacted]	km	6	ED1 6yr average actual unit rates	[redacted]
Switchgear	132kV CB (Gas Insulated Busbars)(ID) (GM)	[redacted]	#	1	ED1 6yr average actual unit rates	[redacted]
Cable	Cable sealing ends and terminal structure	[redacted]	#	1	ED1 6yr average actual unit rates	[redacted]
					Project Sub Total	[redacted]
Category	**Regional Variations and Site-Specific Factors Driving Costs**				**Predominant Costing Approach**	**Impact Cost £k**
Miscellaneous	Land for 132kV switching station				-	[redacted]
Miscellaneous	M25 Crossing				-	[redacted]
					Total Project Cost (Assets)	**10,389**

Table 10: Project Cost Breakdown

The above cost breakdown does not include the associated cost for the procurement of flexible services. It is expected that the use of flexible service to reduce the peak demand and defer convention reinforcement until 2025/26 will cost approximately £56k bringing the total project cost to £10,446k.

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	0	0	X	0	0

Table 11 Investment phasing on deliverability assessment

This investment scheme is part of the wider load-related investment portfolio in RIIO-ED2. SSEN have 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, SEPD have delivered a number of 132kV, 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

This Engineering Justification Paper (EJP) provides relevant information in relation to the load related investment at Upton 132/33kV substation in RIIO-ED2.

The thermal overloading of the 132/33kV circuits is triggered by all DFES scenarios during the ED2 price control.

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

- Option 2: Add New Assets – 132 kV switching station and third circuit
- Option 3: Asset Replacement
- Option 4: 3rd circuit and third Upton BSP transformer
- Option 5: Flexible Solution

The preferred investment for Iver-Chalvey/Upton tee 132 kV network in RIIO ED2 is Option 5: Flexible Solution. The proposed ED2 investment with the combined scheme total of £10.446m. It is proposed flexible services are used to reduce peak demand in 2024/25 and that all reinforcement is carried out in the 2025/26 financial year to minimise the risk of thermal overload and network non-compliance.

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. Assumptions

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028
CR	114.5	117.6	120.6	123.5	126.7	131.6	137.5	143.5	149.7
Firm Capacity	124	124	124	124	124	124	124	124	124
Difference	0	0	0	0	2.7126	7.6211	13.524	19.539	25.671
Customer No. 1% Growth	55,614	56170	56732	57299	57872	58451	59035	59626	60222
MW per customer	0.001333953	0.001359042	0.001387456	0.001414016	0.00144316	0.001488143	0.001544059	0.001600032	0.001658415
No. Faults per Year	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Final Input									
CI	0	0	0	0	-211	-576	-988	-1381	-1757
CML	0	0	0	0	-37937	-103636	-177775	-248541	-316295

Table 13: CI/CML for Do Minimum

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028
CR	114.5	117.6	120.6	123.5	126.7	131.6	137.5	143.5	149.7
Firm Capacity	248	248	248	248	248	248	248	248	248
Difference	0	0	0	0	2.7126	7.6211	13.524	19.539	25.671
Customer No. 1% Growth	55,614	56170	56732	57299	57872	58451	59035	59626	60222
MW per customer	0.002	0.002	0.002	0.002	0.002	0.002	0.00	0.002	0.002
No. Faults per Year	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Final Input									
CI	0	0	0	0	0	0	0	0	0
CML	0	0	0	0	0	0	0	0	0

Table 14: CI/CML for Option 2

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028
CR	114.5	117.6	120.6	123.5	126.7	131.6	137.5	143.5	149.7
Firm Capacity	149	149	149	149	149	149	149	149	149
Difference	0	0	0	0	0	0	0	0	0.67128
Customer No. 1% Growth	55,614	56170	56732	57299	57872	58451	59035	59626	60222
MW per customer	0.002	0.002	0.002	0.002	0.002	0.002	0.00	0.002	0.002
No. Faults per Year	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Final Input									
CI	0	0	0	0	0	0	0	0	-46
CML	0	0	0	0	0	0	0	0	-8271

Table 15: CI/CML for Option 3

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028
CR	114.5	117.6	120.6	123.5	126.7	131.6	137.5	143.5	149.7
Firm Capacity	141	141	141	141	141	141	141	141	141
Difference	0	0	0	0	0	0	0	2.54	8.67
Customer No. 1% Growth	55,614	56170	56732	57299	57872	58451	59035	59626	60222
MW per customer	0.002	0.002	0.002	0.002	0.002	0.002	0.00	0.002	0.002
No. Faults per Year	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Final Input									
CI	0	0	0	0	0	0	0	-179	-594
CML	0	0	0	0	0	0	0	-32299	-106838

Table 16: CI/CML for Option 4

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 our ***Whole System (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 17 below outlines our Whole Systems CBA test for Upton EHV System Reinforcement.

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?
Upton EHV System Reinforcement	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.	Yes	No

Table 17: Whole Systems CBA test for Upton EHV System Reinforcement

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.

We note that reference is made within this EJP to Iver GSP, where there are plans for collaboration with National Grid to deliver reinforcement works that accommodate load growth in Iver GSP's supply area. The focus of this EJP is the circuits fed by Iver GSP and their link to Upton BSP, and the responsibility for reinforcement of these assets lies with SSEN (hence our assessment above that this specific investment is not expected to have any potential Whole Systems solutions). For a consideration of Whole Systems approaches that could be applied at Iver GSP, we refer the reader to our separate EJP regarding Iver 132 kV Fault Level Reinforcement.