SP Energy Networks 2015–2023 Business Plan

Updated March 2014

Annex

Cost Benefit Analysis

SP Energy Networks

March 2014

SP ENERGY NETWORKS

Cost Benefit Analysis

March 2014

Issue Date	Issue No.	Document Owner	Amendment Details
1st July 2013	1.00	Jane Wilkie	First Issue
17th March 2014	2.00	Jane Wilkie	Amended to include greater CBA coverage and introductory text

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1. Scope

This annex contains a summary of all the Cost Benefit Analyses carried out to support our ED1 submission and the process used to develop them.

2. Table of linkages

Document	Chapter / Section
SP Energy Networks Business Plan 2015-2023	Chapter C6 – Expenditure
SP Energy Networks Business Plan 2015-2023 - Annexes	Annex C6 – Expenditure Supplementary Annex – SPEN
SP Energy Networks Business Plan 2015-2023 - Annexes	Annex C5 – Losses Strategy – SPEN
SP Energy Networks Business Plan 2015-2023 - Annexes	Annex C7 – Smart Meter Strategy – SPEN
SP Energy Networks Business Plan 2015-2023 - Annexes	Annex C7 – Smart Grid Strategy - Creating a Network for the Future – SPEN
SP Energy Networks Business Plan 2015-2023 - Annexes	Annex C7 – Innovation Strategy – SPEN

3. Introduction

In this section we have provided a summary of the Cost Benefit Analyses (CBAs) carried out - along with a summary of each of the individual analyses setting out the approach and rationale for our chosen option.

Each of the CBAs have been carried out consistent with our guiding principles to deliver consistent and transparent modelling that is objective, accurate and of high quality.

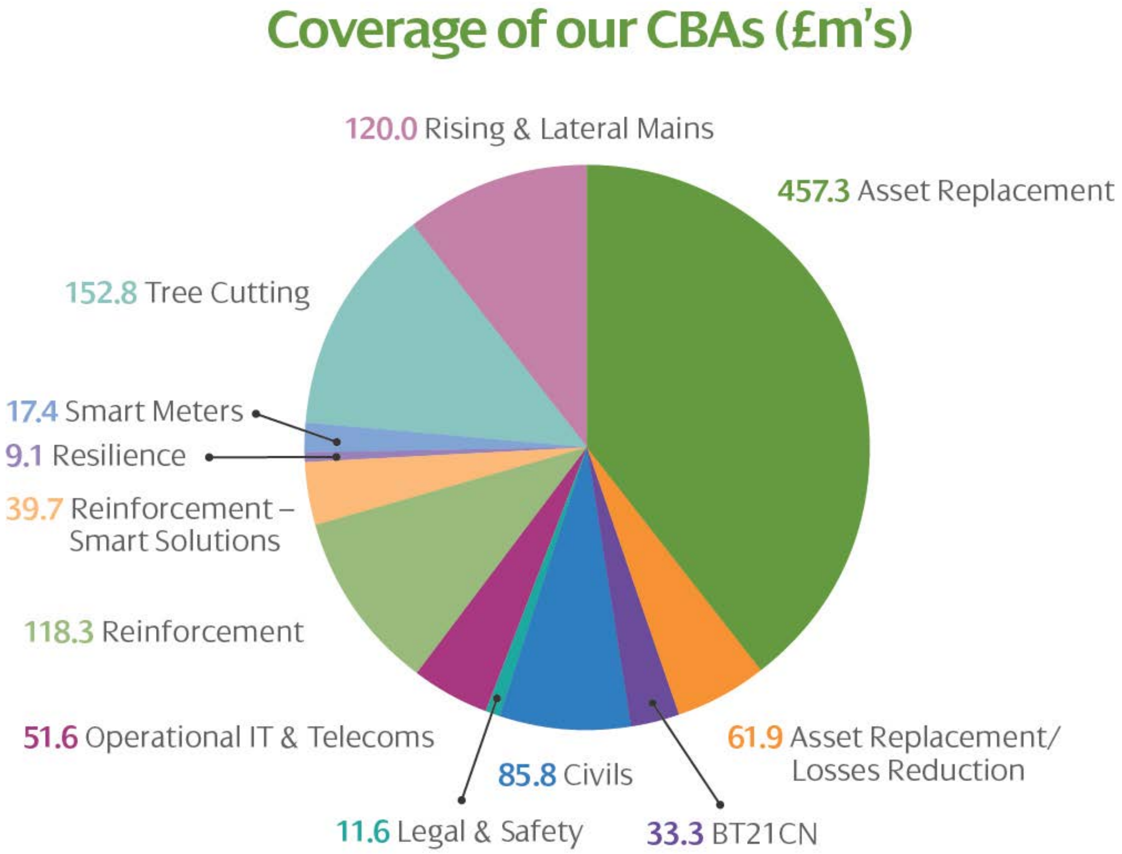
We have carried out cost benefit analysis (CBA) on a large proportion of our investment plan to demonstrate our programme represents value for money for our customers and has properly informed the delivery choices we have made.

We were conscious of the criticism of our Fast Track submission that whilst the quality and robustness of our analysis was considered of high standard we did not cover a sufficient proportion of our overall investment plan.

As a result we have substantially increased both the overall coverage and depth of our analyses and are able to report CBAs have been carried out to justify around 70% of our load and non load related investment plan.

A total of seventy-two (72) individual CBAs have been carried out covering £1.16bn of our investment plan.

A breakdown of coverage by investment area is set out below:



The programmes and schemes chosen for cost benefit analysis fall into the following categories:

- Major replacement and refurbishment schemes and programmes across the asset base.
- Load related reinforcement schemes taking into consideration potential smart grid solutions
- Environmental schemes, OHL undergrounding, loss reduction, tree cutting
- Operational IT and Telecoms (SCADA) projects including BT21CN
- Network future proofing using the Transform Model.
- Civil and structural remediation work.

In addition to the CBAs justifying our Load and Non Load related investment we have also provided specific CBAs justifying our strategic investment in the following areas;

- Smart Grid technology - justifying our Smart Grid strategy
- Smart Meter - justifying our Smart Meter roll-out strategy
- Losses reduction - justifying our Loss reduction strategy
- These CBAs should be read and considered alongside the relevant strategy documentation.

4. CBA Index List

Reference	CBA Title	Licence Area	Investment Area	BPDT Table	ED1 Expenditure £m SPD	SPM	Total
1.1	6.6/11kV Transformer (Losses reduction)	SPD	Asset Replacement/Losses reduction	CV12	2.4		2.4
1.2	6.6/11kV Transformer (Losses reduction)	SPM	Asset Replacement/Losses reduction	CV12		2.5	2.5
2	11kV Circuit Breakers	SPEN	Asset Replacement	CV3	20.7	19.6	40.3
3	Black Start	SPEN	Resilience	CV11	1.6	7.50	9.1
4	HV Pole Refurb (Boron Treatment)	SPEN	Asset Replacement	CV5	Included in CBA # 10		
5	Crewe Reinforcement- Utilising Phase shifting trans	SPEN	Reinforcement - Smart Solutions	CV101, 102, 104		7.0	7.0
6	Mural Wiring	SPEN	Legal & Safety	CV8	0.0	11.6	11.6
7	6.6/11kV Transformer (PM)	SPEN	Asset Replacement	CV3	3.0	4.1	7.1
8	Real Time Thermal Rating (RTTR) Transformer	SPEN	Reinforcement - Smart Solutions	CV101, 102, 104	0.1		0.1
9	11kV Pilot cables	SPEN	Asset Replacement	CV3	6.2	7.4	13.6
10	HV Pole Replacement	SPEN	Asset Replacement	CV3	43.8	40.4	84.2
11	Service Position Modernisation	SPEN	Asset Replacement	CV3	11.0	12.7	23.7
12	LV OHL modernisation	SPEN	Asset Replacement	CV3	18.9	37.1	56.0
13	Whitchurch	SPM	Reinforcement	CV101, 102, 104		18.2	18.2
14	Anglesey	SPM	Reinforcement	CV101, 102, 104		15.8	15.8
15	Wirral _ Birkenhead (132/33kV)	SPM	Reinforcement	CV101, 102, 104		7.7	7.7
16	Lostock	SPM	Reinforcement	CV101, 102, 104		6.4	6.4
18	Brymbo Hawarden Holywell 33kV	SPM	Reinforcement	CV101, 102, 104		6.3	6.3
19	Civic Centre - Electricity Street - Claughton Avenu	SPM	Reinforcement	CV101, 102, 104		2.5	2.5
20	Beaumaris	SPM	Reinforcement	CV101, 102, 104		2.4	2.4
21	Ringway	SPM	Reinforcement	CV101, 102, 104		2.1	2.1
22	Chester Gates - Great Sutton - Little Sutton-Strawl	SPM	Reinforcement	CV101, 102, 104		2.0	2.0
23	Runcorn 11kV	SPM	Reinforcement	CV101, 102, 104		1.8	1.8
24	Coedpoeth	SPM	Reinforcement - Smart Solutions	CV101, 102, 104		0.1	0.1
25	Graig Fawr	SPM	Reinforcement - Smart Solutions	CV101, 102, 104		0.1	0.1
26	Tarvin	SPM	Reinforcement - Smart Solutions	CV101, 102, 104		0.1	0.1
27	Aintree	SPM	Reinforcement	CV101, 102, 104		4.2	4.2
28	Chester Fault Level Mitigation	SPM	Reinforcement - Smart Solutions	CV101, 102, 104		1.1	1.1
29	Warrington	SPM	Reinforcement	CV101, 102, 104		6.1	6.1
30	Gateacre/Huyton Group - Fault Level	SPM	Reinforcement	CV101, 102, 104		4.0	4.0
31	Yoker Ferry Road	SPD	Reinforcement	CV101, 102, 104	4.1		4.1
32	Berwick (North Road/Loaning Relief)	SPD	Reinforcement	CV101, 102, 104	2.8		2.8
33	Gartferry Road	SPD	Reinforcement	CV101, 102, 104	5.0		5.0
34	Erskine Reinforcement	SPD	Reinforcement	CV101, 102, 104	2.8		2.8
35	Lockerbie	SPD	Reinforcement - Smart Solutions	CV101, 102, 104	3.5		3.5
36	Langside	SPD	Reinforcement - Smart Solutions	CV101, 102, 104	0.5		0.5
37	Berwick Ring Voltage Support	SPD	Reinforcement - Smart Solutions	CV101, 102, 104	4.0		4.0
38	Langholm Primary Substation	SPD	Reinforcement - Smart Solutions	CV101, 102, 104	3.8		3.8
39	Broxburn GSP (East Mains / Digital / South Queer	SPD	Reinforcement	CV101, 102, 104	5.8		5.8
40	Ecclefechan (new GSP)	SPD	Reinforcement	CV101, 102, 104	4.9		4.9
41	Dumfries 132/11kV substation	SPD	Reinforcement	CV101, 102, 104	1.7		1.7
42	Portobello 11kV fault level	SPD	Reinforcement	CV101, 102, 104	6.3		6.3
43	Killermont 33kV Fault Level	SPD	Reinforcement	CV101, 102, 104	2.5		2.5
44	West George Street 33kV Fault Level	SPD	Reinforcement	CV101, 102, 104	3.1		3.1
45	Girvan primary Substation Voltage reinforcement	SPD	Reinforcement - Smart Solutions	CV101, 102, 104	2.1		2.1
46	Stranraer Primary Substation Voltage Reinforceme	SPD	Reinforcement - Smart Solutions	CV101, 102, 104	2.5		2.5
47	Smart Meter Rollout	SPEN	Smart Meters	CV109	8.7	8.7	17.4
48	132kV OHL modernisation	SPM	Asset Replacement	CV3	0.0	28.9	28.9
49	Trees (3 year cycle) + ETR	SPEN	Tree Cutting	CV14	62.3	90.5	152.8
50	11kV OHL Rebuild	SPEN	Asset Replacement/Losses reduction	CV3	29.6	27.4	57.0
51.1	11 kV Civil asset refurbishment	SPEN	Civils	CV6	35.7		35.7
51.2	33 kV Civil asset refurbishment	SPEN	Civils	CV6		50.1	50.1
52	132kV Switchgear - Lister Drive modernisation	SPM	Asset Replacement	CV3		9.2	9.2
53	132kV Switchgear - Crewe modernisation	SPM	Asset Replacement	CV3		12.3	12.3
54	132kV Switchgear - Birkenhead modernisation	SPM	Asset Replacement	CV3		9.1	9.1
55	RLM (Rising & Lateral Mains) modernisation	SPEN	Rising Mains	CV110	81.0	39.0	120.0
56	Central Systems modernisation	SPEN	Operational IT & Telecoms	CV105	11.9	17.2	29.1
57	Telecoms (RTUs) modernisation	SPEN	Operational IT & Telecoms	CV105	7.7	14.8	22.5
58	11kV RMUs modernisation	SPEN	Asset Replacement	CV3	12.4	33.3	45.7
59	33kV switchgear - Outdoor (modernisation)	SPEN	Asset Replacement	CV3	1.6	12.9	14.5
60	33kV RMU - Indoor (modernisation)	SPEN	Asset Replacement	CV3		16.1	16.1
61	33kV OHL Rebuild	SPEN	Asset Replacement	CV3	5.5	3.9	9.4
62	LV Plant - Street furniture modernisation	SPM	Asset Replacement	CV3	15.5	12.9	28.4
63	132kV Transformers modernisation	SPM	Asset Replacement	CV3	0.0	27.8	27.8
64.1	33kV Transformers modernisation	SPD	Asset Replacement	CV3	15.6		15.6
64.2	33kV Transformers modernisation	SPM	Asset Replacement	CV3		15.4	15.4
65	BT21CN	SPEN	BT21CN	CV10	5.0	28.3	33.3
66	Voltage Control Relay Functional Enhanceme	SPEN	Reinforcement - Smart Solutions	CV101, 102, 104	4.0	3.9	7.9
67.1	Secondary Substation Monitoring	SPD	Reinforcement - Smart Solutions	CV102	4.0		4.0
67.2	Secondary Substation Monitoring	SPM	Reinforcement - Smart Solutions	CV102		3.0	3.0
68.1	11kV OHL rebuild - losses (SPD)	SPD	Asset Replacement/Losses reduction	CV3	Included in CBA # 50		
68.2	11kV OHL rebuild - losses (SPM)	SPM	Asset Replacement/Losses reduction	CV3	Included in CBA # 50		
	Total # CBAs submitted	**72**			**463.4**	**695.4**	**1158.8**

5. The Cost Benefit Analysis Process

Our objective when developing the CBA process for ED1 was to ensure:

- Consistency & Transparency.
- Objectivity.
- Accuracy and Quality.

Consistency & Transparency

Consistency & transparency was achieved by ensuring the project / scheme owners understood the process of developing the models and had access to key data such as asset deterioration and performance curves and other fixed data sources. Furthermore, it was important we demonstrated how the cost, volume and benefit inputs were derived by clearly setting out any underlying assumptions and including a relatively high level of detail on the make-up of all the input parameters.

A transparent and comprehensive approach to the identification of appropriate options at both the long-list and shortlist stage ensured that the output from the modelling was both robust and of high quality.

Objectivity

Objectivity was achieved by holding the project / scheme owners to account for production of the models, provision of the input cost / benefit data and selection of the preferred investment option.

Accuracy and Quality

Acuuracy and quality was achiieved by ensururing that; first, the models were reviewed by senior engineering management to confirm they were consistent with the business plan submission. Second, the models were reviewed for accuracy by the regulatory and finance teams in order to ensure we had total confidence in both the modelling and the investment decisions that flowed from it.

The outcome from our cost benefit analysis has been fed into our investment plans and is outlined in **Chapter C6 - Expenditure**. In this section we have indicated where cost benefits analysis has either changed, or confirmed our investment plans and here we have set out the rationale for adopting our preferred investment option.

Ofgems' Assessment of our approach to Cost Benefit Analysis

Ofgem commissioned Cambridge Economic Policy Associates Ltd (CEPA) to carry out an independent assessment of each DNOs cost benefit analysis submission at July 2013. We were assessed vary favourably, strongly supporting our assertion of delivering long term value for money. CEPA's report - Ofgem RIIO-ED1 Support – Work Area F Scottish Power states –

"SP's analysis shows good adherence to the Guidance provided by Ofgem throughout the analysis. In general they are the only Group to consistently provide detailed information on the costings underpinning their different options, rather than just including the costs in the different options".

CEPA go on to state,

"importantly our more detailed assessment of their models suggests that they have generally considered a sensible range of options, taking the care to assess relevant strategies /approaches for each of their CBAs."

The report goes on to comment that perhaps greater CBA coverage of the overall investment programme could have been carried out. We accept this feedback and therefore in this final March 2014 Business Plan we have reviewed all of our CBAs and increased our coverage to around 70% of the total load and non-load investment programme amounting to £1.16bn.

In addition we have extended the scope of our analyses in order to set out clear cost justifications for our investment in Smart Metering, Smart Grid solutions and our Losses Reduction strategy (**Annex C5 – Losses Strategy – SPEN**). More detail on our Cost Benefit Analysis methodology is contained within **Chapter C6 - Expenditure**.

6. Appendix A – CBA Summaries

CBA No.	1.1
Scheme/Project Name	HV Transformer Replacement
Scheme/Project Owner	Peter Sherwood
Primary Investment Objective	Reduce the SPD company's carbon footprint
Secondary Investment Objective (Engineering)	To replace our inefficient/ High Loss 11kV transformers

Option no.	Options considered	Decision
1	Baseline - Replace HV distribution transformers driven by ED1 RMU programme only.	Rejected
2	On top of baseline, target high loss units (pre 1962) outwith RMU programme based on load	Accepted
2.1	Sensitivity 1 - on top of Option 2 replace 100 more high loss transformers per annum	Rejected
2.2	Sensitivity 2 - Option 2 with estimated EU losses/costs	For information only
3	On top of baseline, replace remainder of all high loss (pre 1962) HV distribution transformers in ED1	Rejected

Background & Justification

The current investment strategy for 11kV transformers is to either replace or refurbish units driven by the RMU replacement programme or on fault. In ED1, in addition to this strategy we will include an allowance on top of this target for high loss units (pre 1962). The intervention depends on the health index of the unit and its loading. Replacement is required for all HI5 assets which are determined by, high acidity readings, or poor site specific, condition based assessment.

The guidelines for secondary transformers are;

- Replace, with new, all high loss (pre-1962) transformers associated with a planned or faulted replacement of a RMU;
- Replace, with new, all highly loaded high loss (pre-1962) transformers;
- Replace, with new, transformers that are 1962 onwards, if there is strong evidence of degradation (oil acidity/poor condition) and the transformer can be declared end of life (Health Index 5).

Approach to the Options Appraisal

- *Option 1 is always a 'do minimum'/ Business as usual Option. All the costs and benefits associated with the other options are relative to the do minimum Option (Option 1).*
- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

We have used the following information to calculate our final values which we have used to populate our CBA tables:

1. Condition based volume
2. Losses based volume
3. Unit Cost
4. Replacement profile over ED1
5. Typical no-load loss of a pre 1955 unit
6. Typical no-load loss of a 1955-1961 unit
7. Typical no-load loss of a new unit
8. Fixed costs as provided

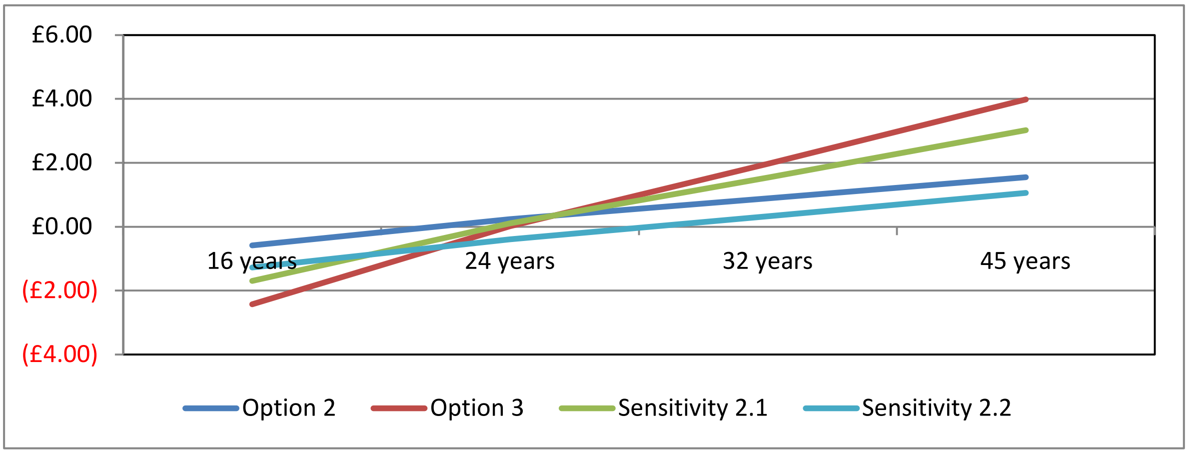
The EU have indicated their intention to specify a maximum losses figure for distribution transformers. This will have a knock on cost impact. The ENA commissioned a report on the potential impact of the proposed losses reduction. A sensitivity was added here, for information only, indicating the impact on the CBA of the proposals. Although it still retains a positive NPV against the base case, it clearly shows it has a detrimental effect compared to the existing supplied transformers.

Business as Usual Option (Baseline/Option 1)

Our Business as usual option (Baseline/Option 1) is to replace HV distribution transformers driven by ED1 RMU programme only.

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*

Through carrying out the cost benefit analysis we have justified the need to work on top of the baseline target high loss units (pre 1962) out with RMU programme based on load. (Option 2). Option 2 does not return the highest NPV, however, we have utilised engineering justification to confirm that replacement of the remainder of all high loss (pre 1962) HV distribution transformers in ED1 on top of the baseline (Option 3) would have deliverability constraint and system access issues.



We can see from the above graph that our chosen option 2 is the most stable option. Not only is this the most stable in terms of NPV but it also has siginificant environmental qualities. We will replace units on top of the baseline target high loss units (pre 1962) out with RMU programme based on load.

Option 2:

On top of baseline target high loss units (pre 1962) out with RMU programme based on load.

Term (years from first out flow)	NPV (£m)
16	-£0.58
24	£0.24
32	£0.89
45	£1.55
first year of investment out flow	1

Option 3:

On top of baseline, on top of baseline, replace remainder of all high loss (pre 1962) HV distribution transformers in ED1.

Term (years from first out flow)	NPV (£m)
16	-£2.42
24	£0.01
32	£1.97
45	£3.98
first year of investment out flow	1

Sensitivities

Sensitivity 2.1:

On top of Option 2 replace 100 more high loss transformers per annum.

Term (years from first out flow)	NPV (£m)
16	-£1.70
24	£0.10
32	£1.54
45	£3.02
first year of investment out flow	1

Sensitivity 2.2:

Option 2 with EU losses/costs.

Term (years from first out flow)	NPV (£m)
16	-£1.27
24	-£0.40
32	£0.32
45	£1.06
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Attach CBA spreadsheet here =➔

Options considered	Comment
Option 1 (Baseline)	Replace HV distribution transformers driven by ED1 RMU programme only
Option 2	On top of baseline, target high loss (pre 1962) and poor condition units out with RMU programme (ED1 plan) based on load
Option 3	On top of baseline, replace remainder of all high loss (pre 1962) HV distribution transformers in ED1
Option 4	Replace all HV distribution transformers when they reach their 65th birthday (65 years is EOL as per deterioration models) in ED1. This has been ruled out as it is not a deliverable profile

List below the short list of those options which have been costed within this CBA workbook

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	Baseline- Replace HV distribution transformers driven by ED1 RMU programme only	Rejected			£0.00	£0.00	£0.00	£0.00	£0.00
2	on top of baseline target high loss units (pre 1962) out with RMU programme based on load	Adopted	Most economic option	Technical losses and other environmental	-£0.24	£0.60	£1.26	£1.92	
3	on top of baseline, replace remainder of all high loss (pre 1962) HV distribution transformers in ED1	Rejected	Rejected on the basis of delivery constraint		-£1.29	£1.23	£3.22	£5.20	
2.1	sensitivity 1 - on top of Option 2 replace 100 more high loss transformers per annum	Rejected	Rejected on the basis of deliverability constraint and system access		-£0.88	£0.98	£2.44	£3.90	
2.2	sensitivity 2 - Option 2 with estimate of EU losses/costs		For information only		-£0.80	£0.12	£0.85	£1.57	

Investment Business Case

CBA No.	1.2
Scheme/Project Name	HV Transformer Replacement
Scheme/Project Owner	Peter Sherwood
Primary Investment Objective	Reduce the SPM company's carbon footprint
Secondary Investment Objective (Engineering)	To replace our inefficient/ High Loss 11kV transformers

Option no.	Options considered	Decision
1	Baseline- Replace HV distribution transformers driven by ED1 RMU programme	Rejected
2	on top of baseline, target high loss (pre 1962) and poor condition units outwith RMU programme based on load	Adopted
2.1	sensitivity 1 - Option 2 with estimated EU losses/costs	For information only
3	replace all high loss (pre 1962) HV distribution transformers in ED1	Rejected

Background & Justification

The current investment strategy for 11kV transformers is to either replace or refurbish units driven by the RMU replacement programme or on fault. In ED1, in addition to this strategy we will include an allowance on top of this target for high loss units (pre 1962). The intervention depends on the health index of the unit and its loading. Replacement is required for all HI5 assets which are determined by, high acidity readings, or poor site specific condition based assessment.

The guidelines for secondary transformers are;

- Replace, with new, all high loss (pre-1962) transformers associated with a planned or faulted replacement of a RMU;
- Replace, with new, all highly loaded high loss (pre-1962) transformers;
- Replace, with new, transformers that are 1962 onwards, if there is strong evidence of degradation (oil acidity/poor condition) and the transformer can be declared end of life (Health Index 5).

Approach to the Options Appraisal

- *Option 1 is always a 'do minimum'/ Business as usual Option. All the costs and benefits associated with the other options are relative to the do minimum Option (Option 1).*
- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

We have used the following information to calculate our final values which we have used to populate our CBA tables:

- Condition based volume
- Losses based volume
- Unit Cost
- Replacement profile over ED1
- Typical no-load loss of a pre 1955 unit
- Typical no-load loss of a 1955-1961 unit
- Typical no-load loss of a new unit
- Fixed costs as provided

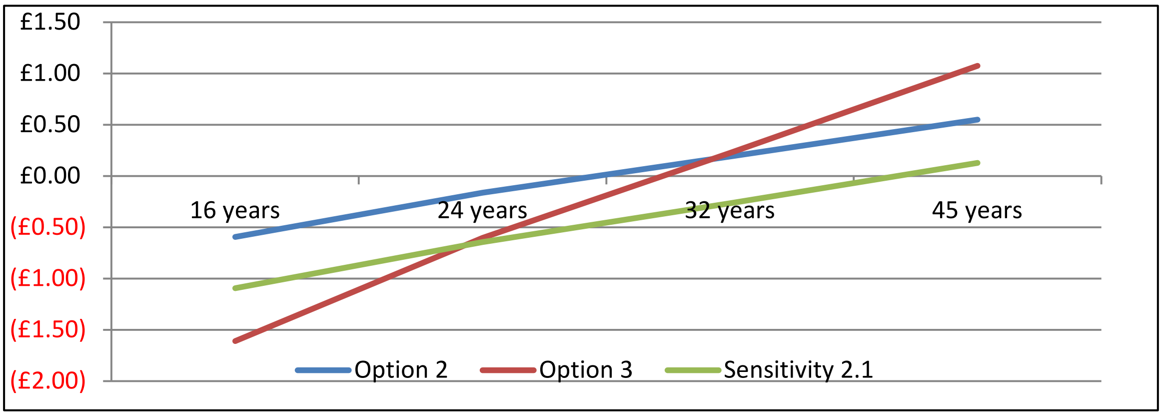
The EU have indicated their intention to specify a maximum losses figure for distribution transformers. This will have a knock on cost impact. The ENA commissioned a report on the potential impact of the proposed losses reduction. A sensitivity was added here, for information only, indicating the impact on the CBA of the proposals. Although it still retains a positive NPV against the base case, it clearly shows it has a detrimental effect compared to the existing supplied transformers.

Business as Usual Option (Baseline/Option 1)

Our Business as usual option (Baseline/Option 1) is to replace HV distribution transformers driven by ED1 RMU programme only.

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*

Through carrying out the cost benefit analysis we have justified thel need to work on top of the baseline target high loss units (pre 1962) out with RMU programme based on load. (Option 2). Option 2 does not return the highest NPV, however, we have utilised engineering justification to confirm that replacement of the remainder of all high loss (pre 1962) HV distribution transformers in ED1 on top of the baseline (Option 3) would have deliverability constraint and system access issues.



Option 2:

On top of baseline target high loss units (pre 1962) out with RMU programme based on load.

Term (years from first out flow)	NPV (£m)
16	**-£0.59**
24	**-£0.16**
32	**£0.19**
45	**£0.55**
first year of investment out flow	1

Option 3:

Replace all high loss (pre 1962) HV distribution transformers in ED1.

Term (years from first out flow)	NPV (£m)
16	**-£1.61**
24	**-£0.60**
32	**£0.22**
45	**£1.07**
first year of investment out flow	1

Sensitivities

Sensitivity 1:

Option 2 with EU losses/costs.

Term (years from first out flow)	NPV (£m)
16	**-£1.09**
24	**-£0.64**
32	**-£0.26**
45	**£0.13**

first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Attach CBA spreadsheet here =➔

Options considered	Comment
Option 1 (Baseline)	replace HV distribution transformers driven by ED1 RMU programme
Option 2	on top of baseline target high loss (pre 1962) and poor condition units out with RMU programme (ED1 plan) based on load
Option 3	replace all high loss (pre 1962) HV distribution transformers in ED1
Option 4	replace all HV distribution transformers when they reach their 65th birthday (65 years is EOL as per deterioration models) in ED1. This has been ruled out as it does not reduce the carbon footprint from the baseline and is not a deliverable profile

List below the short list of those options which have been costed within this CBA workbook

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	Baseline- replace HV distribution transformers driven by ED1 RMU programme	Rejected			£0.00	£0.00	£0.00	£0.00	
2	On top of baseline target high loss (pre 1962) and poor condition units out with RMU programme based on load	Adopted	Most economic option	Technical losses and other environmental	-£0.44	-£0.01	£0.33	£0.67	
3	Replace all high loss (pre 1962) HV distribution transformers in ED1	Rejected	rejected on the basis of delivery constraint		-£1.40	-£0.32	£0.55	£1.41	
2.1	Sensitivity- Option 2 with estimated EU losses/costs		For information only		-£0.88	-£0.44	-£0.07	£0.29	

Investment Business Case

CBA No.	2
Scheme/Project Name	11kV Circuit Breakers
Scheme/Project Owner	Frank Berry
Primary Investment Objective	To manage deteriorating 11kV CBs
Secondary Investment Objective (Engineering)	A cost effective engineering balance in relation to retrofitting, replacement and refurbishment solutions and extend asset life.

Option no.	Options considered	Decision
1	Replacement only (baseline)	Rejected
2	Retrofit / Refurbish / Replace	Adopted
3	Refurbish Only	Rejected
4	Retrofit Only	Rejected

Background & Justification

The strategy for 11kV primary switchgear is;

1. Replace all HI5 end of life assets;
2. Undertake financially justifiable interventions on 11kV circuit breakers to improve health indices and extend life by between 10 and 20 years. This is achieved by addressing known condition or performance issues utilising either a retrofit or refurbishment solution.

Our policy in ED1 is to replace HI5 assets and to manage the deterioration of HI4 and HI3 circuit breakers through refurbishment or retrofit of the moving portion achieving a life extension of between 10-20 years.

In terms of health index improvement, asset replacement achieves a movement from HI5 to HI1 whereas retrofit can result in an improvement in health index from HI4 to HI2 and HI4 to HI3 or HI3 to HI2 for refurbishment.

HI5 switchboards will continue to be replaced. In the past, if the moving portion was end of life then the complete unit was replaced. Now, however, fewer switchboards will require complete replacement since we have a cost effective retrofit solution in the current market place. At selected sites HI5 or HI4 OCB moving portions shall be retrofitted when the fixed portion is a minimum of HI3 following maintenance and/or refurbishment works. Where an existing fixed portion asset life is expected to be <10 years then refurbishment shall be considered as an option where the safety and/or circuit performance is enhanced. Utilising quality data engineering judgement is required to ensure that sites are selected where the civil, heating and environment costs are a minimum thus ensuring that a cost effective solution is delivered. Where moving portions are retrofitted the switchboard asset life (fixed and moving portions) is expected to be minimum of 20 years. In conjunction with the ENA, SPEN continue to steer manufacturers to increase solutions where SPEN switchgear volumes nearing end of life dictate.

We have tried to strike the correct engineering balance thus maintaining safety and reliability whilst allowing us to maximise resources efficiently and as a result are not using the highest NPV in option 3.

<u>Business as Usual Option (Baseline/Option 1)</u>

Our baseline for this CBA is to continue normal practices of replacement only including routine maintenance to ensure safety and reliability. This will also include replacing all Health Index 5, end of life assets.

<u>Chosen Option</u> *<u>(Includes engineering justification if not choosing the highest NPV)</u>*

We have chosen an engineering balance of Retrofit / Refurbish / Replace. Although the Refurbish only and the retrofit only Options have a clearly positive NPV and financial benefit we have ruled both Option 3 and 4 out. We rejected both options on the basis of sound engineering judgement. We determined that it was not our strategy to refurbish units at end of life. We also agreed that engineering solutions are only available for a few switchgear types. In addition, we cannot guarantee the actions of suppliers for setting retrofit costs.

Approach to the Options Appraisal

- *Option 1 is always a 'do minimum'/ Business as usual Option. All the costs and benefits associated with the other options are relative to the do minimum Option (Option 1).*
- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Assumptions Made:

Volumes used:
Utilising quality data SPEN have identified that 378 11kV OCBs will be retroffited with VCB moving portions in ED1 and 682 OCB's will be replaced under switchboard replacements i.e. by installing Fixed Pattern Metal Enclosed Swgear. 528 units will be refurbished. Option 2 is therefore in reference to this engineering balance of solutions. Routine & post fault maintenance and associated oil costs are included and multiplied by OCB volumes which diminish over time. The reduced volume of replacement only (baseline) allows these other cost effective solutions to be implimented.

Potential Post Fault Maintenance Cost savings :
For the purposes of calculating Potential Post Fault Maintenance costs the 2012 fault rate was used. The number of faults in relation to asset base was used to allow the Average to be calulated. The % rate was then applied to the volume of OCB's each year.

Potential Oil and Handling Cost savings:
The cost of purchasing oil was applied to the average OCB volume to determine a reduction over time as OCB volumes on the network are reduced.

We have considered maintenance costs per annum for each type of CB and also considered the number of faults.

We have included a CI/CML cost in the Refurb options. The reason being is that the refurbishment option will result in us having OCB's which historically have still failed to trip despite refurb and maintenance being carried out. We must assume that Retrofit and Replace options would eliminate this slow/failure to trip issue with these being new kit. We would still need to input a proportional cost to the Retrofit/Refurb/Replace option though. i.e. 33% is refurb therefore 33% impact costs allocated. Replace option only will benefit though.

Option 2:
Option 2 involves investigating the balance of retrofitting versus replacement. We have found that by using this balance we can maximise the utilisation of resources. It does this by allowing HI5 switchboards to be replaced and also allows for an additional investment retrofit solution to increase reliability, safety while extending the asset life by 20yrs minimum. The retrofit solution shall be implemented where the fixed portion can be refurbished or maintained to a minimum of HI3. Where the asset life of the switchboard is less than 10 years, refurbishment shall be considered to increase safety, reliability and performance. Within our chosen option we can see that we will use the following volumes in our calculation.

Term (years from first out flow)	NPV (£m)
16	£15.51
24	£15.35
32	£11.70
45	£8.52
first year of investment out flow	1

Option 3:
To Refurbish Only. This was rejected because it is not the most economic option over the life of the equipment. We have used a refurbish volume of 85 per year.

Term (years from first out flow)	NPV (£m)
16	£19.28
24	£13.47
32	£10.33
45	£6.99
first year of investment out flow	1

Option 4:
To Retrofit Only. This was rejected as engineering solutions are only available for a few switchgear types. In addition, progressing suppliers to have retrofits will change the focus. We cannot guarantee the actions of suppliers for setting retrofit costs and this has also became a consideration.

Term (years from first out flow)	NPV (£m)
16	£20.36
24	£21.13
32	£13.80
45	£6.95
first year of investment out flow	1

We have used a retrofit fit volume of 199 per year.

Sensitivities

N/A

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario (Option 1)	Continue normal practices including routine maintenance to ensure safety and reliability. Replace asset at end of life (HI5)
Option 2 Retrofit / Refurbish / Replace	The engineering balance of retrofitting versus replacement maximises utilisation of resources allowing HI5 switchboards to be replaced as per normal investment plans but allows for an additional investment retrofit solution to increase reliability, safety while extending the asset life by 20yrs minimum. The retrofit solution shall be implemented where the fixed portion can be refurbished or maintained to a minimum of HI3. Where the asset life of the switchboard is <10 years then refurbishment shall be considered to increase safety, reliability and performance.
Option 3	Switchgear refurbishment only
Option 4	Switchgear retrofitting only

List below the short list of those options which have been costed within this CBA workbook

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	sed on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	Baseline - Replacement only	Rejected	not the best cost/benefit option		£0.00	£0.00	£0.00	£0.00	
2	Retrofit / Refurbish / Replace	Adopted	The options on this sheet clearly demonstrate both refurbishment and retrofitting are beneficial and should be delivered where they are feasible and meet the strategy. A optimised blend of the 3 Rs is the adopted option.		£15.51	£15.35	£11.70	£8.52	
3	Refurbish Only	Rejected	Not economic over lifetime of the asset		£19.28	£13.47	£10.33	£6.99	
4	Retrofit Only	Rejected	Not economic over lifetime of the asset		£20.36	£21.13	£13.80	£6.95	

Investment Business Case

CBA No.	3
Scheme/Project Name	Black Start
Scheme/Project Owner	Alyn Jones
Primary Investment Objective	To validate the planned approach to be taken by SPEN in achieving the required level of resilinece to meet our obligation and our stakeholder expectations
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
1	Option 1	Rejected
2	Option 2	Rejected
3	Option 3	Rejected
4	Option 4	Adopted

Background & Justification

This CBA is to validate the planned approach to be taken by SPEN in achieving the required level of resilience to meet our obligation and our stakeholder expectations. Within SPEN, a portfolio of solutions has been developed to equip substation auxiliary AC and DC supply systems with a minimum resilience of 72 hours, at our Grid and Primary substations.

The GB Power Network is normally operated in a state of dynamic equilibrium between connected load and available generation. In the rare event that this equilibrium is disturbed then the result could be total or widespread loss of the power network. Recovery from this situation is termed 'Black Start'.

Substation Black Start resilience is a specific requirement for delivery in ED1 to ensure SPEN can comply with Government requirements. Over the past decade or more DNO's including SPEN have replaced large numbers of low burden electro-mechanical protection relays with more sophisticated equipment to enhance network performance. However, these replacement relays are typically micro-processor based with increased power consumption than the traditional electro-mechanical units and therefore place a higher continuous demand on the Substation DC battery supply, therefore once mains (external) power supplies are lost to the substation, the relays will drain the tripping /protection battery more quickly than earlier scheme designs.

Loss AC & DC site supplies will delay the recovery of the network following a black start.

Grid substations generally have both AC and DC requirements that require to be maintained during an outage to ensure its primary and secondary systems remain available. At such locations a standby generator will be installed, to provide power the site essential services.

Grid substations without an AC motive power dependency for circuit breakers and associated disconnector's and all Primary Substations wherever possible will be fitted with an enhanced battery and charger unit. The battery will be sized for 72 hours resilience based on standing substation DC load.

At Primary substations where physical accommodation does not allow for the housing of replacement larger capacity (and size) battery and charger units, or where the current standing load provides for marginal resilience in the order of 48 hours, a battery DC load management will be implemented.

Where such battery DC load management arrangements are implemented then amendments will be required to modify the Primary transformer 'Back up' protection supply arrangements such that it remains continually connected to the site protection battery. This will ensure that upon re-energisation of the Power Network under Black Start conditions there will be a required level of protection in place to clear any local network faults which have occurred in the down time, until individual 11kV circuit protection systems are fully powered up and in service.

Battery Load Management schemes, whilst effective in prolonging the resilience of the site battery; do however introduce the risk of failure to the electronic relays for which the battery provides the DC source. SPEN estimate that the mortality rate of between 1:100 to 1:200 is considered likely which when applied across the primary substations in SPD & SPM could conservatively impact in excess of 500 relays with consequential impact on the integrity of the power network, danger to staff, the general public and property. Failures of relays during the initial phase of Black Start restoration process will also introduce doubt, and consequential delays into the restoration process.

Primary Substations with predominance of electro-mechanical relays (minimal battery drain) are excluded, and will be upgraded in line with asset modernisation programme/or site change of use.

Site visits will be scheduled/undertaken to assess battery condition within the operational response to a Black Start event.

Business as Usual Option (Baseline) - Global LV generator installation
Baseline case is based on installing a standby generator at all Grid & Primary substations, that have a 'significant' AC or DC requirement. This is the least intrusive option as it simply replaces mains AC with an alternate source. In addition supplement 6 locations (3 north/3 south with enhanced standby generation)

Primary Substations with predominance of electro-mechanical relays (minimal battery drain) are excluded, and will be upgraded in line with asset modernisation programmes/or site change of use.

Considered too expensive and over complicated for all substation configurations

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*

As a result of the various considerations, we have decided to use (Option 4) generation/72 hr battery capacity at Grid Substations, plus 72hr capacity battery capacity/battery dc load management schemes applied to primary substations . This option has the best NPV and has been chosen as it has a balanced portfolio of solutions and balanced engineering/societal risk.

Approach to the Options Appraisal

- *Option 1 is always a 'do minimum'/ Business as usual Option. All the costs and benefits associated with the other options are relative to the do minimum Option (Option 1).*
- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

The following options were considered before making our final decision:

We have made the following assumptions for all options;

1. I & M Opex cost based on £1000/annum generator maintenance cost by 3rd party provider costs incurred with one year lag from installation
2. Assumed future replacement of battery cells to policy and funded normally by I&M

Option 1 - Combination of solutions portfolio
Fit standby generation to all Grid Substations in line with SPT RIIO T1 outcome. In addition supplement 6 operational muster locations (3 north/3 south with enhanced standby generation) .

Fit 72hr capacity battery units to all primary substations with significant DC burden from microprocessor based protection.

Substations with predominance of electro-mechanical relays (minimal battery drain) are excluded, and will be upgraded in line with asset modernisation programmes /or site change of use.

To fully deliver this option with enhanced battery/charge units it is likely that there will be some engineering/accommodation difficulties to overcome which have not been quantified or costed.

Term (years from first out flow)	NPV (£m)
16	**£19.63**
24	**£26.89**
32	**£32.74**
45	**£40.17**
first year of investment out flow	1

Conclusion - meets engineering requirements but full battery/charger unit replacement likely to run into insurmountable accommodation/cost issues.

<u>Option 2: - Combination of solutions portfolio</u>
Fit standby generation to all Grid Substations with multiple Transformers and/or AC dependent CB's and Fit 72hr capacity battery units to all simple GT site installations (Single Tx and/or no AC dependent CB's etc). In addition supplement 6 operational muster locations (3 north/3 south with enhanced standby generation).

Fit 72hr capacity battery units to primary substations with significant DC burden from microprocessor based protection and install Battery DC load disconnection schemes where civil accommodation becomes uneconomic. Enhance battery monitoring at VRLA battery substations .

Substations with predominance of electro-mechanical relays (minimal battery drain) are excluded, and will be upgraded in line with asset modernisation programme/or site change of use.

Term (years from first out flow)	NPV (£m)
16	**£22.45**
24	**£30.57**
32	**£37.04**
45	**£45.15**
first year of investment out flow	1

Conclusion - meets engineering requirements, takes account of likely accommodation issues for full battery replacement but does not over rely on single solution or Battery DC load disconnection solution and potential relay mortality issues.

<u>Option 3: - Combination of solutions portfolo var2</u>
Fit standby generation to all Grid Substations with multiple Transformers and/or AC dependent CB's and Fit 72hr capacity battery units to all simple GT site installations (Single Tx and/or no AC dependent CB's etc). In addition supplement 6 operational muster locations (3 north/3 south with enhanced standby generation).

Fit Battery DC load disconnection schemes to all primary substations with significant DC burden from microprocessor based protection to preserve existing battery capability beyond 72hrs (including battery replacement where required).

Substations with predominance of electro-mechanical relays (minimal battery drain) are excluded, and will be upgraded in line with asset modernisation programme/or site change of use.

Term (years from first out flow)	NPV (£m)
16	£23.81
24	£32.30
32	£39.02
45	£47.40
first year of investment out flow	1

Conclusion - meets engineering requirements, but considered rejected due to potential relay mortality issues impacting on Safety to Staff/Public and assets. Also likely to add significant risk to restoration profile.

Option 4: - Re-balanced portfolio of solutions and balanced engineering/sociatal risk – **Chosen Option**

Fit standby generation to all Grid Substations with multiple Transformers and/or AC dependent CB's and Fit 72hr capacity battery units to all simple GT substations installations (Single or DoubleTx and/or no AC dependent CB's etc).

Fit 72hr capacity battery units to primary substations with significant DC burden from microprocessor based protection and install Battery DC load management schemes where civil accommodation becomes uneconomic. Enhance battery monitoring at VRLA battery substations .

Primary Substations with predominance of electro-mechanical relays (minimal battery drain) are excluded, and will be upgraded in line with asset modernisation programme/or site change of use.

Term (years from first out flow)	NPV (£m)
16	£24.06
24	£32.62
32	£39.38
45	£47.81
first year of investment out flow	1

Conclusion – delivers best NPV - meets engineering requirements, takes account of likely accommodation issues for full battery replacement and does not over rely on single solution or/and potential relay mortality issues.

Appendix 1: Cost Benefit Analysis

List below all options considered to meet the stated aim

Options considered	Comment
Upgrade equipment in line with normal attrition rate	Fails to meet expected requirements or timeline for full 'blackstart' resilience
Global upgrade of batteries to 72 hr capacity	Fails to cover AC motive power requirements and has incumbent accommodation issues
Operational response	Would fail to meet expected restoration strategy/requirements or timescales
Global Battery DC supply disconnection units	Fails to cover AC motive power requirements and has incumbent accommodation issues
Base Case - Global LV generator installation	Considered too expensive and over complicated for all substation configurations
OPTION 1 - Combination of solutions portfolio	Generation applied to all Grid Sites consistent with SPT, 6 operational sites, plus 72hr battery capacity batteries in Primaries with Significant DC loading
OPTION 2 - Combination of solutions portfolio	Generation/72 hr battery capacity at Grids, generation at 6 operational sites, plus 72hr capacity battery capacity/dc load disconnection scheme applied to primary sites - Electronic relay mortality rates due to loss of DC raises risk of Safety
OPTION3 - Combination of solutions portfolio var2	Generation/72 hr battery capacity at Grids requiring ac, Generation at 6 operational locations and battery load disconnection schemes applied at all other sites (assume 40% of sites need new batteries in line with 20 year asset replacement policy) - Re-balanced portfolio of solutions and balanced engineering/societal risk
OPTION 4 - Re-balanced portfolio of solutions and balanced engineering/societal risk	Fit standby generation to all Grid Sites with multiple Transformers/ or AC dependent CB's and Fit 72hr capacity battery units to all simple GT site installations (Single/dual Tx No AC dependent CB's etc).
Operational response	Would fail to meet expected restoration strategy/requirements or timescales
Global Battery DC supply disconnection units to all sites Grid & Primary	Fails to cover AC motive power requirements and has incumbent accommodation issues
Upgrade equipment in line with normal attrition rate	Fails to meet expected requirements or timeline for full 'blackstart' resilience

List below the short list of those options which have been costed within this CBA workbook

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	Install generators at all locations	Rejected							
1	Generation applied to all Grid Sites consistent with SPT, 6 operational sites,	Rejected	Least economic option		£19.63	£26.89	£32.74	£40.17	
2	As option 1 plus 72hr capacity battery capacity/dc load disconnection scheme	Rejected	Least economic option		£22.45	£30.57	£37.04	£45.15	
3	Generation/72 hr battery capacity at Grids requiring ac, Generation at 6	Rejected	Least economic option		£23.81	£32.30	£39.02	£47.40	
4	Re-balanced portfolio of solutions and balanced engineering/societal risk	Adopted	Most economic option		£24.06	£32.62	£39.38	£47.81	

Investment Business Case

CBA No.	4
Scheme/Project Name	Boron Treatment of Wooden Poles
Scheme/Project Owner	Dave Kilday
Primary Investment Objective	Improve the reliability of an increasingly ageing network
Secondary Investment Objective (Engineering)	To determine whether to replace or treat HI4 decayed wood poles with Boron.

Option no.	Options considered	Decision
1 (Baseline)	Boron Treatment	Adopted
2	Replace Poles	Rejected
2.1	Sensitivity - Reduce the cost of replacing the poles as used in option 2.	Rejected

Background & Justification

Our policy for 33kV and 11kV overhead lines is based on a strategy to improve the reliability of an increasingly aging network, rebuild lines to a resilient fit for purpose specification and rectify all ESQCR hazards.

We will assess all wood poles in lines that are being refurbished, boron treat HI4 decayed poles where technically feasible and replace HI5 poles and HI4 poles that are not suitable for boron treatment. Replacement achieves a movement from HI5 to HI1 and treatment will result in an improvement in health index from HI4 to HI3 optimising life extension and achieving an additional 10+ years of life.

As a result of carrying out Cost benefit analysis we have determined that it is entirely unviable to replace the poles as this will return a significantly negative NPV. We will continue to refurbish poles using Boron treatment unless the pole is end of life.

Business as Usual Option (Baseline/Option 1)

We carry out a detailed condition assessment of the pole. We boron treat HI4 decayed wood poles where the residual strength is above 80% of the original and the decay is confined to the ground level area.

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*

We have chosen our business as usual option in this case as there is no financial or engineering benefit in replacing the pole where the residual strength of the HI4 decayed pole is less than 90% of the original.

Approach to the Options Appraisal

- *Option 1 is always a 'do minimum'/ Business as usual Option. All the costs and benefits associated with the other options are relative to the do minimum Option (Option 1).*
- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Assumptions:

- The calculation period is over 45 years as this is Ofgem’s assumed life for the assets.
- The number of poles to be replaced/ treated is 49712
- The expected lifetime of a new pole is 63 years (HSE Deterioration curve)
- The time when deterioration begins is 30 years.
- Expected life increase after treatment is 10 years.

Option 1 (Baseline)- Treatment of HI4 wood pole
Detailed condition assessment of the pole. Boron treat HI4 decayed wood poles where the residual strength is above 80% of the original and the decay is confined to the ground level area. NPV is 0 as this is the baseline and current method used.

Option 2- Replacement of HI4 wood pole
Detailed condition assessment of the pole. Replace the pole where the residual strength of the HI4 decayed pole is less than 90% of the original.

Term (years from first out flow)	NPV (£m)
16	-£33.33
24	-£29.27
32	-£27.36
45	-£24.83
first year of investment out flow	1

Sensitivities

Sensitivity 2.1- Reduce the cost of Pole replacement by 25%

Term (years from first out flow)	NPV (£m)
16	-£26.62
24	-£23.36
32	-£21.82
45	-£19.79
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Option1 Baseline: Treatment of HI4 wood pole	Detailed condition assessment of the pole. Boron treat HI4 decayed wood poles where the residual strength is above 80% of the original and the decay is confined to the ground level area.
Option 2: Replacement of HI4 wood pole	Detailed condition assessment of the pole. Replace the pole where the residual strength of the HI4 decayed pole is
Sensitivity 2.1: Reducing the cost of Pole replacement by 25%	NPV is reduced only marginally. Not sufficient to make this option any more viable

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	Baseline- Treatment of HI4 wood pole	Accepted	Boron Treatment is considerably more cost effective than pole replacement		£0.00	£0.00	£0.00	£0.00	
2	Option 2 - Replace Poles	Rejected			-£33.33	-£29.27	-£27.36	-£24.83	
2.1	Sensitivity 2.1- Reduce Pole Replacement Costs by 20%	Rejected			-£26.62	-£23.36	-£21.82	-£19.79	

Investment Business Case

CBA No.	5
Scheme/Project Name	Crewe Reinforcement
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Strategic investment in the electricity distribution system in Cheshire in order to increase supply security and facilitate future load growth in the local area.
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	To establish a new 132kV circuit between Cellerhead GSP and Crewe Grid.	Rejected
1	To install a Power Flow Controler at Crewe Grid to connect the Cellarhead GSP and Fiddlers Ferry/Carrington GSP Group.	Adopted
2	To establish a double circuit tower line between Barlaston and Crewe Grid substations.	Rejected

Background & Justification

The 132kV system in Crewe and the surrounding area is supplied via three 132kV circuits. One of the circuits is fed from Cellarhead GSP (owned and operated by National Grid) and the other two circuits are fed from metered supply points at Whitfield and Barleston substations (owned and operated by WPD). Studies indicate the group has a winter maximum demand of approximately 240MVA (including DSCs and losses) and is 'ER P2/6 Class of Supply D' (over 60MW and up to 300MW). Initial P2/6 assessments indicate it is necessary to maintain the full group demand of approximately 240MVA for n-1 outages and restore approximately 80MVA within three hours for n-2 outages. Studies indicate the capacity availability on the Whitfield circuit will be exceeded for n-1 outage conditions with the demand forecast the in the RIIO ED1 period. Studies also indicate the capacity availability on the Barlaston circuit will be significantly exceeded for an n-2 outage conditions with the demand forecast the in the RIIO ED1 period making it necessary to disconnect significant levels of demand. The options listed below take consideration of the wider 132kV and 33kV system requirements and 'SPM 'Best View Scenario' for capacity based on WS3 analysis. A range of smart solutions have been considered with Option 1 being the most appropriate smart solution as initial indications are that it could offer significant saving when compared to the conventional reinforcement solutions.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

<u>**Business as Usual Option (Baseline) -** establish a new 132kV circuit between Cellerhead GSP and Crewe Grid.</u>

The Baseline Scenario identified is to is to establish a new 132kV circuit between Crewe Grid and Cellerhead in order to secure the group and facilitate future demand growth. The Baseline Scenario has been established based on conventional options available to reinforce the SPM system and any alternative options available to the adjacent DNOs network will be explored as the project progresses. Initial studies indicate that the Baseline Scenario would resolve all thermal issues identified, would significantly increase supply security and cater for long term load growth in the area. This option is based on establishing a significant 132kV overhead line and there is a risk of cost fluctuation if the ratio of 132kV cable to overhead line increases as the project progresses through the consenting process.

<u>Option 1 - install a Power Flow Controller at Crewe Grid to connect the Cellarhead GSP and Fiddlers Ferry/Carrington GSP Group (Smart Solution) – **Chosen Option**</u>

Option 1 is to further explore the feasibility, and if appropriate following detailed analysis, to install a 132kV Power Flow Controller (PFC) at Crewe Grid to couple the Cellarhead GSP and Fiddlers Ferry/Carrington GSP Groups. The 132kV switchboard at Crewe Grid Substation is a significant 132kV connection point and is the normal operational split point between these supergrid groups that have a significant voltage angle difference between them. If this split point were closed it would cause power flow issues and raise fault levels above plant ratings in several 33kV groups and is therefore always operated 'open'. The use of PFC on the SP Manweb network is not a well understood solution and therefore as part of the detailed design assessments it is proposed to utilise external expertise to assess the viability of this option. If detailed assessments indicate it is a viable to install a PFC then it could potentially significantly increase supply security/capacity availability in the Crewe/Lostock Demand group and defer the conventional reinforcement. The existing 132kV switchgear at Crewe is planned to be replaced under the asset modernisation program within the ED1 price control period and therefore the installation of a PFC at this site would be relatively straightforward. If detailed assessments indicate that this option is technically viable, there is the potential for significant costs savings and reduced environmental impact when compared with the conventional SPM reinforcement solutions. The PFC would increase 33kV fault levels in area, with the Warrington and Crewe 33kV substation groups being likely to require switchgear to be replaced and therefore a provisional sum of £1m has been included for this within the overall estimate. The installation of a PFC at Crewe would connect three GSPs (Cellarhead/Fiddlers Ferry/Carrington) and part of the interconnection would be via a 132kV network that is owned and operated by WPD. Therefore, detailed analysis of the SPM, WPD and National Grid system will be required to assess the viability of this possible smart solution from their perspective and reach an agreement. The alternative conventional options involve significant 132kV overhead lines to be constructed with the potential alternative being £20m and this is some £13m more than this possible smart solution at an estimated £7m. There is also a risk of a significant fluctuation in the cost of the conventional solution if the ratio of cable to overhead line increases following the planning and consenting of the circuit. Given that there is a level of uncertainty associated with the potential smart solution of installing a PFC at Crewe it is proposed to also progress some of the pre-engineering works associated with the conventional solution in case the PFC option is found to be unviable following detailed analysis and liaison with National Grid/WPD.

Term (years from first out flow)	NPV (£m)
16	£5.83
24	£8.01
32	£9.49
45	£11.04
first year of investment out flow	1

Option 2 - establish a double circuit tower line between Barlaston and Crewe Grid substations.

This option is to rebuild the PK line as a double circuit L4 tower line between Crewe and Barlaston Grid substations in order to establish an additional 132kV in feed into Crewe. Initial studies indicate that the Option 2 would resolve all thermal issues identified, would significantly increase supply security and cater for long term load growth in the area. This option assumes that Barlaston substation (owned and operated by WPD) can accommodate an additional 132kV bay and that the required capacity on the WPD network is available at this point. Due to the high cost associated with this option it is not proposed that it will be progressed any further.

Term (years from first out flow)	NPV (£m)
16	-£3.44
24	-£4.86
32	-£5.82
45	-£6.84
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario is to establish a new 132kV circuit between Cellerhead GSP and Crewe Grid.	The Baseline Scenario identified is to is to establish a new 132kV circuit between Crewe Grid and Cellerhead in order to secure the group and facilitate future demand growth. The Baseline Scenario has been established based on conventional options available to reinforce the SPM system and any alternative options available to the adjacent DNOs network will be explored as the project progresses. Initial studies indicate that the Baseline Scenario would resolve all thermal issues identified, would significantly increase supply security and cater for long term load growth in the area. This option is based on establishing a significant 132kV overhead line and there is a risk of cost fluctuation if the ratio of 132kV cable to overhead line increases as the project progresses through the consenting process.
Option 1 is to install a Power Flow Controller at Crewe Grid to connect the Cellarhead GSP and Fiddlers Ferry/Carrington GSP Group. (Smart Solution)	Option 1 is to further explore the feasibility, and if appropriate following detailed analysis, to install a 132kV Power Flow Controller (PFC) at Crewe Grid to couple the Cellarhead GSP and Fiddlers Ferry/Carrington GSP Groups. The 132kV switchboard at Crewe Grid Substation is a significant 132kV connection point and is the normal operational split point between these supergrid groups that have a significant voltage angle difference between them. If this split point were closed it would cause power flow issues and raise fault levels above plant ratings in several 33kV groups and is therefore always operated 'open'. The use of PFC on the SP Manweb network is not a well understood solution and therefore as part of the detailed design assessments it is proposed to utilise external expertise to assess the viability of this option. If detailed assessments indicate it is a viable to install a PFC then it could potentially significantly increase supply security/capacity availability in the Crewe/Lostock Demand group and defer the conventional reinforcement. The existing 132kV switchgear at Crewe is planned to be replaced under the asset modernisation program within the ED1 price control period and therefore the installation of a PFC at this site would be relatively straightforward. If detailed assessments indicate that this option is technically viable, there is the potential for significant costs savings and reduced environmental impact when compared with the conventional SPM reinforcement solutions. The PFC would increase 33kV fault levels in area, with the Warrington and Crewe 33kV substation groups being likely to require switchgear to be replaced and therefore a provisional sum of £1m has been included for this within the over all estimate. The installation of a PFC at Crewe would connect three GSPs (Cellarhead/Fiddlers Ferry/Carrington) and part of the interconnection would be via a 132kV network that is owned and operated by WPD. Therefore, detailed analysis of the SPM, WPD and National Grid system will be required to assess the viability of this possible smart solution from their perspective and reach an agreement. The alternative conventional options involve significant 132kV overhead lines to be constructed with the potential alternative being £20m and this is some £13m more than this possible smart solution at an estimated £7m. There is also a risk of a significant fluctuation in the cost of the conventional solution if the ratio of cable to overhead line increases following the planning and consenting of the circuit. Given that there is a level of uncertainty associated with the potential smart solution of installing a PFC at Crewe it is proposed to also progress some of the pre-engineering works associated with the conventional solution in case the PFC option is found to be unviable following detailed analysis and liaison with National Grid/WPD.
Option 2 is to establish a double circuit tower line between Barlaston and Crewe Grid substations.	This option is to rebuild the PK line as a double circuit L4 tower line between Crewe and Barlaston Grid substations in order to establish an additional 132kV in feed into Crewe. Initial studies indicate that the Option 2 would resolve all thermal issues identified, would significantly increase supply security and cater for long term load growth in the area. This option assumes that Barlaston substation (owned and operated by WPD) can accommodate an additional 132kV bay and that the required capacity on the WPD network is available at this point. Due to the high cost associated with this option it is not proposed that it will be progressed any further.
To extend the Crewe to Whitfield 132kV circuit to Cellerhead.	This option is remove the Crewe circuit from Whitfield grid substation (owned and operated by WPD) and to extent to Cellerhead GSP. This option will be explored further following discussions with WPD/National grid, however, as demand increases it may not provide the level of capacity and required in the longer term and it does not increase the groups supply security when assessing it in terms of an n-2 scenario during the summer period.
Adjacent DNO (WPD) to reinforce their system in order to provide level of supply capacity required on the SPM system.	Discussions are ongoing with WPD about options to accommodate the level of demand required and it is proposed that the least cost solution will be established for the overall electricity system in the area. However, as demand increases a solution to reinforce the WPD system to increase capacity availability at the metered supply points may not provide the level of capacity and supply security required for the Crewe area.
To install a Automatic Load Transfer scheme	Initial assessments indicate this option would not be viable as due to the meshed nature of the SPM network it would be necessary to auto transfer large sections of the system to the adjacent GSP group and would therefore not be technically viable.
Dynamic thermal ratings of existing 132kV circuits	If capacity can be secured from the WPD supply points then this option may provide some further headroom on the SPM system and will be explored further as the scheme progresses.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	To establish a new 132kV circuit between Cellerhead GSP and Crewe Grid.	Rejected	The Baseline Scenario has been rejected at this stage on the basis that if it is determined to be feasible the smart solution outlined in Option 1 would provide significant cost savings and reduced environmental impact.						
1	To install a Power Flow Controler at Crewe Grid to connect the Cellarhead GSP and Fiddlers Ferry/Carrington GSP Group.	Adopted	It is proposed to explore this smart solution on the bases that it may defer the conventional reinforcement and provide significant cost savings with reduced environmental impact.		£5.83	£8.01	£9.49	£11.04	
2	To establish a double circuit tower line between Barlaston and Crewe Grid substations.	Rejected	This option has been rejected based on cost as it is significantly more that the alternatives with no additional system benefit.		-£3.44	-£4.86	-£5.82	-£6.84	

Investment Business Case

CBA No.	6
Scheme/Project Name	Mural Wiring
Scheme/Project Owner	Dave Kilday
Primary Investment Objective	Public Safety
Secondary Investment Objective (Engineering)	Determine optimal solution for the modernisation of poor performing urban mural wiring

Option no	Comment	Decision
1	Baseline- Repairing the mural wiring upon failure	Rejected
2	Like for Like Replacement	Rejected
3	Like for Like Replacement after 25 years	Adopted
4	Protected Mural Wiring Replacement	Rejected
5	Underground Replacement	Rejected

Background & Justification

Mural wiring is a system of wiring which is unique to SPM. The nature of the original installation of these particular systems on the external fabric of the property has resulted in significant public safety issues. Our strategy is to complete the modernisation of the Health Index 5 installations in RIIO-ED1 and the Health Index 4 installations in RIIO-ED2. All Health Index 5 installations shall be rectified by the end of RIIO-ED1. A cost benefit analysis has been carried out to determine the optimal method of replacing this system has shown that, where technically viable and acceptable to our customers, poor condition external wiring should be replaced with new systems of external concentric cable and wall mounted furniture compliant.

We undertook an independent audit of mural wiring, and subsequently extrapolated this audit across the SPD and SPM networks. The audit was disaggregated using postcode and housing type. Our condition-based audits have placed the assets into five categories as detailed in our policy for asset health indices.

- Cat 1: As New - In excellent working order and condition and as such fully performs its operational function.
- Cat 2: Good Condition – No longer new but still in good condition, with no operational issues.
- Cat 3: Minor Deterioration - Showing some signs of deteriorating condition but still in reasonable working order and has minimal or no operational issues.
- Cat 4: Material Deterioration – Significant deterioration in condition resulting in some operational issues. May become ‘End of Life’ within 5-10 years.
- Cat 5: End of Life - Serious signs of deterioration due to age, wear and suitability that cannot be rectified. May have critical issues that operationally restrict the network and may pose a danger to staff, public or the network. It should generally be replaced within 5 years.

Business as Usual Option (Baseline/Option 1)

The baseline option is to replace the mural wiring upon failure. It is obvious that this is not a feasible option in terms of not only safety but customer service.

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*

Renewing the mural wiring on a "like for like" basis every 25 years, where technically feasible. This provides the best NPV.

Approach to the Options Appraisal

- *Option 1 is always a 'do minimum'/ Business as usual Option. All the costs and benefits associated with the other options are relative to the do minimum Option (Option 1).*
- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Assumptions:

1. There are a number of examples where alterations to the building, e.g. the erection of a conservatory, means that it is not technically feasible to renew the mural wiring "like for like". Only those installations where it is technically feasible to renew the mural wiring "like for like" are considered here.
2. While the life expectancy of mural wiring is approx 55 years, deterioration will start after 25

years.
3. It is not possible to determine the number of faults on mural wiring installations as they are generally classified as "cable faults". During 2011/12, only 7 faults were properly classified as mural wiring faults.
4. Of the 7 faults listed in the CBA workings, the average CI was 2 and the average CML was 429 minutes.
5. The deterioration curve for concentric cable mural wiring is not known as the deterioration curves for concentric cable all assume an underground installation. In both instances, however, there is approx 30 years between the start of deterioration and end of life. It can, therefore, be assumed that the curve for concentric cable for mural wiring will follow the same curve as an underground concentric cable from the start of deterioration to the end of life.

Option 2:
Like for Like Replacement

Term (years from first out flow)	NPV (£m)
16	£3.30
24	£5.38
32	£7.42
45	£10.49
first year of investment out flow	1

Option 3:
Like for Like Replacement after 25 years

Term (years from first out flow)	NPV (£m)
16	£3.30
24	£5.38
32	£8.02
45	£12.71
first year of investment out flow	1

Option 4:
Protected Mural Wiring Replacement

Term (years from first out flow)	NPV (£m)
16	£2.56
24	£4.43
32	£7.49
45	£12.65
first year of investment out flow	1

Option 5:
Underground Replacement

Term (years from first out flow)	NPV (£m)
16	-£2.30
24	-£1.77
32	£0.39
45	£4.62
first year of investment out flow	1

Sensitivities

N/A

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Option 1 (Baseline)	Repairing the mural wiring on failure is not an acceptable option.
Option 2	Renewing the mural wiring on a "like for like" basis, where technically feasible.
Option 3	Renewing the mural wiring on a "like for like" basis every 25 years, where technically feasible.
Option 4	Renewing the mural wiring on a "like for like" basis, where technically feasible but applying mechanical and UV protection to the wiring for its full length.
Option 5	Cost of undergrounding the service is considerably higher than renewing the mural wiring.

List below the short list of those options which have been costed within this CBA workbook

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	Baseline- Repairing the mural wiring on failure	Rejected			£0.00	£0.00	£0.00	£0.00	
2	Like for Like Replacement	Rejected	Least economic option		£3.30	£5.38	£7.42	£10.49	
3	Renewing the mural wiring on a "like for like" basis every 25 years, where technically feasible.	Adopted	Most economic option	Network Investment Core Costs	£3.30	£5.38	£8.02	£12.71	
4	Protected Mural Wiring Replacement	Rejected	Least economic option		£2.56	£4.43	£7.49	£12.65	
5	Underground Replacement	Rejected	Least economic option		-£2.30	-£1.77	£0.39	£4.62	

Investment Business Case

CBA No.	7
Scheme/Project Name	Pole Mounted Transformers
Scheme/Project Owner	Dave Kilday
Primary Investment Objective	To optimise the replacement or refurbishment of pole mounted transformers while carrying out overhead line rebuild and refurbishment works.
Secondary Investment Objective (Engineering)	To replace HI4 and HI5 pole mounted transformers.

Option no.	Options considered	Decision
1	Baseline- Replace pole mounted transformers with new transformers when off-line rebuilding overhead lines.	Rejected
2	Replace pole mounted transformers with refurbished transformers	Adopted
2.1	Option 2 with decreased fault rate of 5% for Refurbished Transformers.	Rejected
2.2	Option 2 with increased Refurbished Transformer costs of 5%	Rejected
3	Reuse existing pole mounted transformers	Rejected

Background & Justification

When lines are off-line rebuilt, the new line is erected with the old line still in situ. New transformers are therefore brought to site and installed on the new line. The old transformers are returned to the depot and those which are Health Index 4 or 5 are scrapped, and the remainder are re-used for faults. There are approx 240 HI 4 HI5 transformers per annum from these lines. If the HI4 and HI5 transformers were refurbished, they could be re-used on new rebuild lines in preference to using new transformers.

When lines are in-line rebuilt, the components from existing line are replaced as required to bring the line up to the requisite construction standard. All transformers are inspected and tested and, where they pass the inspection they are retained for continued use on that line. Approx 240 HI 4 and HI5 transformers per annum will remain in situ on these lines and be allowed to fail.

If the HI4 and HI5 transformers were refurbished, they could be re-used on new rebuild lines in preference to using new transformers. When lines are refurbished, all transformers are inspected and tested and, where they pass the inspection, they are retained for continued use on that line. Approximately 2,000 HI 4 and HI5 transformers per annum will remain in situ on these lines. It is not viable to replace these transformers under a refurbishment outage.

For our Cost Benefit Analysis we have considered whether we should replace pole mounted transformers with refurbished transformers or whether to reuse existing pole mounted transformers.

Business as Usual Option (Baseline/Option 1)

Our business as usual method is to replace the pole mounted transformers with new transformers when off-line rebuilding overhead lines.

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*

We have decided to utilise Option 2 and replace the pole mounted transformers with refurbished transformers. By using Option 3 there would be a slight financial advantage in the long term, however, only replacing on failure would be detrimental to our customers needs and could not overcome the inconvenience to customers and the unnecessary additional workload.

Approach to the Options Appraisal

- *Option 1 is always a 'do minimum'/ Business as usual Option. All the costs and benefits associated with the other options are relative to the do minimum Option (Option 1).*
- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Option 2:
Replace pole mounted transformers with refurbished transformers. Whilst not the lowest cost option in the long term, when combined with the customer service and workload aspects, this option achieves the optimal solution.

Term (years from first out flow)	NPV (£m)
16	£2.72
24	£2.44
32	£2.06
45	£1.91
first year of investment out flow	1

Option 3:
Reuse existing pole mounted transformers. Although there is a slight financial advantage in the long term of only replacing on failure, it is not significant enough to overcome the inconvenience to customers and the unnecessary additional workload.

Term (years from first out flow)	NPV (£m)
16	£2.63
24	£2.27
32	£2.16
45	£2.20
first year of investment out flow	1

Sensitivities

Sensitivity 2.1
Decrease failure rate of refurb PM Transformers by 5%

Term (years from first out flow)	NPV (£m)
16	£2.74
24	£2.53
32	£2.20
45	£2.10
first year of investment out flow	1

Sensitivity 2.2
Increase refurb cost by 5%

Term (years from first out flow)	NPV (£m)
16	£2.69
24	£2.41
32	£2.02
45	£1.86
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Attach CBA spreadsheet here =➔

Options considered	Comment
Option 1 Baseline scenario: Replace pole mounted transformers with new transformers when off-line rebuilding overhead lines.	When lines are off-line rebuilt, the new line is erected with the old line still in situ. New transformers are therefore brought to site and installed on the new line. The old transformers are returned to the depot and those which are Health Index 4 or 5 are scrapped, and the remainder are re-used for faults. There are approx 240 HI 4 HI5 transformers per annum from these lines.
Option 2 - Replace pole mounted transformers with refurbished transformers when off-line	If the HI4 and HI5 transformers were refurbished, they could be re-used on new rebuild lines in preference to using new transformers.
Option 2.1 Sensitivity on Option 2	Option 2 with decreased fault rate of 5% for Refurbished Transformers.
Option 2.2 Sensitivity on Option 2	Option 2 with increased Refurbished Transformer costs of 5%
Option 3 - Reuse existing pole mounted transformers when in-line rebuilding overhead lines.	When lines are in-line rebuilt, the components from existing line are replaced as required to bring the line up to the requisite construction standard. All transformers are inspected and tested and, where they pass the inspection they are retained for continued use on that line. Approx 240 HI 4 and HI5 transformers per annum will remain in situ on these lines and be allowed to fail.
Replace pole mounted transformers when refurbishing overhead lines.	When lines are refurbished, all transformers are inspected and tested and, where they pass the inspection, they are retained for continued use on that line. Approximately 2,000 HI 4 and HI5 transformers per annum will remain in situ on these lines. It is not viable to replace these transformers under a refurbishment outage.

List below the short list of those options which have been costed within this CBA workbook

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	Baseline- Replace pole mounted transformers with new transformers when off-line rebuilding overhead lines.	Rejected			£0.00	£0.00	£0.00	£0.00	
2	Replace pole mounted transformers with refurbished transformers	Adopted	Most economic option	Network Investment Core Costs	£2.75	£2.48	£2.09	£1.94	
2.1	Option 2 with decreased fault rate of 5% for Refurbished Transformers.		We are using an assumed fault rate of refurbished PM Transformers. Should our assumed fault rate be 5% less we will obtain a higher NPV than option 2 as well as having more customer service benefits.		£2.77	£2.56	£2.23	£2.13	
2.2	Option 2 with increased Refurbished Transformer costs of 5%		This option will return a greater NPV at an earlier stage, however in the long term it will result in a slightly lower NPV to option 2. We still maintain that Option 1 has far superior customer service benefits.		£2.72	£2.44	£2.05	£1.89	
3	Reuse existing pole mounted transformers	Rejected	Marginally better NPV in the longer term but rejected for customer service implications of multiple outages		£2.66	£2.31	£2.19	£2.23	

Investment Business Case

CBA No.	8
Scheme/Project Name	RTTR Transformer
Scheme/Project Owner	Allan Collinson
Primary Investment Objective	The aim is to install the smart grid solution RTTR (real time thermal rating) transformer in order to defer the assets reinforcement a number of years.
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
1	Baseline- Current reinforcement strategy with the installation of new 33/11 kV transformers to resolve thermal capacity issue in primary	Rejected
2	Smart grid solution option: real time thermal rating (RTTR)	Adopted

Background & Justification

The aim is to install the smart grid solution RTTR (real time thermal rating) transformer in order to defer the assets reinforcement a number of years.

Approach to the Options Appraisal

- *Option 1 is always a 'do minimum'/ Business as usual Option. All the costs and benefits associated with the other options are relative to the do minimum Option (Option 1).*
- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline/Option 1) - Current reinforcement strategy with the installation of new 33/11 kV transformers to resolve thermal capacity issue in primary substations.

For sites where the group demands are reaching their firm capacity, regarding a generic load growth in their area at average temperature conditions, the transformers would be expected to exceed its firm capacity within the period of ED1. There are four sites in SPM where the level of uncertainty in the demand level means that they are good candidates for monitoring and/or Real Time Ratings of the Transformer. These four sites are Coedpoeth, Tarvin, Graig Fawr and Bootle Litherland.
For Coedpoeth, the allocation of a new primary substation on the Brymbo site will remove demand from Coedpoeth up to 2 MVA of the existing demand, which reached 7.1 MVA in 2011 being 7.5 MVA its firm capacity.
In Tarvin, the highest transformer maximum demand was 7.3 MVA in 2011. Therefore, the installation of a second transformer would share demand and enable medium term load growth and future outages to be taken with minimal load transfer. This would give Tarvin a firm of 10 MVA but with the connections to the remote sites load could be transferred and Tarvin could support up to 15 MVA of demand.
Graig Fawr recorded a maximum demand of 7 MVA in 2011. The replacement of the existing transformer for a 7.5/10 MVA unit will enable a further 2 MVA load growth in the area.
In the Bootle/Litherland 33 kV group one 33 kV cable circuit will be loaded above its FCO rating so to remove the thermal issue it is proposed to overlay it with a 400mm2 Aluminium 33 kV cable.
The life expectancy of these conventional solutions is over 45 years.

Chosen Option – Option 2 - Smart grid solution option: real time thermal rating (RTTR)

Term (years from first out flow)	NPV (£m)
16	£0.58
24	£0.52
32	£0.48
45	£0.42
first year of investment out flow	1

The installation of real time thermal rating (RTTR) transformer in those primary substations reaching their firm capacity would predict the rating and hence the current carrying capacity of assets in a real-time mode. The use of measurement and ambient forecasting data would manage the thermal capacity headroom issues. The benefit would be to reach and additional capacity of around 10% according to manufacturers, therefore the installation of reinforcement transformers can be deferred. The life expectancy of this solution is 40 years.

Appendix 1 - Cost Benefit Analysis (Excel Spreadsheet) Attached

Options considered	Comment
Option 1 Baseline scenario - Conventional solution: current reinforcement strategy with the installation of new 33/11 kV transformers to resolve thermal capacity issue in primary substations.	For sites where the group demands are reaching their firm capacity, regarding a generic load growth in their area at average temperature conditions, the transformers would be expected to exceed its firm capacity within the period of ED1. There are four sites in SPM where the level of uncertainty in the demand level means that they are good candidates for monitoring and/or Real Time Ratings of the Transformer. These four sites are Coedpoeth, Tarvin, Graig Fawr and Bootle Litherland. For Coedpoeth, the allocation of a new primary substation on the Brymbo site will remove demand from Coedpoeth up to 2 MVA of the existing demand, which reached 7.1 MVA in 2011 being 7.5 MVA its firm capacity. In Tarvin, the highest transformer maximum demand was 7.3 MVA in 2011. Therefore, the installation of a second transformer would share demand and enable medium term load growth and future outages to be taken with minimal load transfer. This would give Tarvin a firm of 10 MVA but with the connections to the remote sites load could be transferred and Tarvin could support up to 15 MVA of demand. Graig Fawr recorded a maximum demand of 7 MVA in 2011. The replacement of the existing transformer for a 7.5/10 MVA unit will enable a further 2 MVA load growth in the area. In the Bootle/Litherland 33 kV group one 33 kV cable circuit will be loaded above its FCO rating so to remove the thermal issue it is proposed to overlay it with a 400mm2 Aluminium 33 kV cable. The life expectancy of these conventional solutions is over 45 years.
Option 2 Smart grid solution option: real time thermal rating installation.	The installation of real time thermal rating (RTTR) transformer in those primary substations reaching their firm capacity would predict the rating and hence the current carrying capacity of assets in a real-time mode. The use of measurement and ambient forecasting data would manage the thermal capacity headroom issues. The benefit would be to reach and additional capacity of around 10% according to manufacturers, therefore the installation of reinforcement transformers can be deferred. The life expectancy of this solution is 40 years.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	Baseline- Current reinforcement strategy with the installation of new 33/11 kV transformers to resolve thermal capacity issue in primary	Rejected			£0.00	£0.00	£0.00	£0.00	
2	Smart grid solution option: real time thermal rating (RTTR)	Adopted			£0.58	£0.52	£0.48	£0.42	

Investment Business Case

CBA No.	9
Scheme/Project Name	11kV Pilots
Scheme/Project Owner	P. Dolan
Primary Investment Objective	Maintain current frontier levels of customer service and safety in urban areas against aging asset base
Secondary Investment Objective (Engineering)	To repair and modernise poorly performing UG protection pilots (HV)

Option no.	Options considered	Decision
1	Baseline	Rejected
2	Do Nothing	Rejected
3	Proactive Scenario	Adopted
3.1	Sensitivity to degradation and repair rates	
3.2	Sensitivity to degradation and repair rates and reduced repair rates	
4	Monitoring Scenario	Rejected

Associated investment is contained with the following investment table lines (along with other pilot cable investment);

- Fault Repairs - 11kV pilot fault fault repairs
- Pilot Section Replacements - CV3 Asset Replacement UG Pilots Overlays

Background & Justification

There is an increase in investment forecast for the area of UG pilot cables from previous price review periods. Current expenditure on this area is above forecast for the price review period. In ED1 this investment will be used to repair/ modernise degrading as pilot failure/degradation discovery rate increases due to proactive condition assessment works.

The purpose of carrying out the CBA analysis was to benchmark reactive and proactive strategies for management of the HV cable pilot assets. The analysis examined financial impacts of not investing adequately in the asset base and identified how programme activities which maintained current frontier levels of customer service and safety in urban areas appeared financially in contrast to other options.

Pilots cables are aging assets which are degrading, have been installed when the power system was established and associated HV cables were installed . These assets are fundamental to the operation of unit protection deployed on interconnected HV networks in urban areas.

Business as Usual Option (Baseline/Option 1)

Our Baseline/ Business as usual to management of HV Pilot Cables is Reactive Investment, currently 11kV pilot cables are repaired upon discovery as soon as repair works can be arranged.

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*

The option with the highest NPV is Option 3 (the proactive investment approach), a scenario where pilot cables are proactively condition assessed and repaired / modernised if found in degraded condition. This is a responsible management option which is also the best option financially as shown in the models.

There is also merit in Option 4 if monitoring systems where installed selectively improve CI/CML improvement, this option is not included in business plan.

Approach to the Options Appraisal

- *Option 1 is always a 'do minimum'/ Business as usual Option. All the costs and benefits associated with the other options are relative to the do minimum Option (Option 1).*
- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Within each option we have assumed that:

1. CI/CML performance on unit protected 11kV networks dependant on 11kV pilots is best demostrated by HV fault performance of Mersey Region as the HV network is mainly of this type.
2. As the fault performance of network completely dependant on associated pilots, we have assumed that fault performance to dip to national average if pilots were removed.
3. An annual Increase of 128 (uplift in faults which cause) customer interuptions fault would be the result of the removal of all 11kV protection pilots, based on current fault rates.
4. The average customer interuption per additional customer interruption fault is based on fault impact scenarios on associated networks likely to result when pilots are not functional
5. The total CI uplift per annum if all pilots were removed would be Average CI x Uplift in faults

which cause interruptions.

6. The total CML uplift is the CI uplife X Average ML per interuption
7. In addition to reactive fault repairs, networks faults have exposed unknown pilot failures. Increasing fault rate is expected as pilot asset age and proactive condition monitoring will uncover unknown faults, the assumed pilot failure rate is best view considering these factors.
8. The CI / CML uplift per year associated with the failure of pilots will be the percentage not repaired every year x the CI/CML uplift expected if the assets were not to exist. If there is a short fall in the no. of pilots modernised / repaired per year against fault rate (and fault rates /repair rates are constant), the CI/CML impact will increase year on year.
9. Annual Impact applied over 45 years .
10. Other consequential damage has been modelled (LV cable burnouts) but the impact is less significant than CI and CML uplift

Baseline/ Option 1

Within this option we used the financial / Customer impact of base level of investment. We have used a pilot failure rate of 0.83% of the population per annum for all options and assumed that 0.11% of pilots will remain uncleared (with faults) per annum under this scenerio.

Option 2: Do Nothing Approach

The Financial / Customer impact of no investment is included for comparison and emphases the importance of this asset base. We have assumed a 0.83% failure rate for this option (as per the note above and other options) and that all failures discovered will remain uncleared as no investment is made to restore condition.

Term (years from first out flow)	NPV (£m)
16	-£9.51
24	-£15.12
32	-£21.68
45	-£27.09
first year of investment out flow	8

Option 3: Proactive Investment

Proactive testing and repair of degraded assets (including short section replacements). We have assumed a 0.83% failure rate for this option (as per other options) and that with proactive investment all discovered faults will be repaired or modernised. This does not address the underlining pilot faults on the systems which will only be detectable if associated protections are called to operate outside of maintenance testing as pilots are currently unmonitored.

Term (years from first out flow)	NPV (£m)
16	£0.57
24	£1.22
32	£1.98
45	£3.44
first year of investment out flow	1

Option 4: Monitoring Scenario

We have assumed a 0.83% failure rate for this option (as per other options) and that as with option 3 all discovered pilot faults will be repaired or modernised. As condition monitoring helps manage the asset base, after the installed equipment is installed, we will have the opportunity to address the underlining pilot faults on the systems which will only be detectable outside of maintenance testing as pilots. This could lead to CI and CML improvement. Our Business plan includes Option 3. Option 4 could be considered as a inititave to improve CI/CML improvement if applied selectively, this option is not included in business plan.

Term (years from first out flow)	NPV (£m)
16	-£0.06
24	£0.51
32	£1.25
45	£2.73
first year of investment out flow	1

Sensitivities

Sensitivity 3.1

Sensitivity to degradation and repair rates (10% increase in pilot failures per annum).

Term (years from first out flow)	NPV (£m)
16	-£0.20
24	-£0.27
32	-£0.31
45	-£0.31
first year of investment out flow	1

Sensitivity 3.2

Sensitivity to degradation and repair rates and reduced repair rates (10% increase in failures plus 5% reduction in repair rates)

Term (years from first out flow)	NPV (£m)
16	-£0.56
24	-£0.97
32	-£1.40
45	-£2.09
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Option 1- Baseline	Reactive Investment - Repair (on discovery)
Options 2	Do Nothing (Does not meet objective) - This scenario has been modelled as it shows the fincancial impact of not investing in this asset.
Options 3	Proactive Pilot Fault Discovery and increased investment
Options 4	Installation of basic monitoring (£6k per Primary Substation) and increased investment made to repair discovered faults, this approach has the potential to reduce the proportion of faults where customers are disconnected over the long term.
Options 5	Installation of indivdual monitoring systems and increased investment for discovered faults - Dismissed as costly and impractical. Given the volume of monitors required >5000 secondary substations @ £2k equipment + installation, the capital requirements for the programme would be significant. The biggest challenge however would be deliverability as the resources required to deliver this scale of programme are not available within the business and could not be readily found in the open market
Options 6	Remove dependancy on pilots - Dismissed due to costs and deliverability. If the dependancy on 11kV pilots was to be removed significant investment and resource commitment would be required in the form of spliting the LV network and configuration of switchgear to guard against potentially dangerous conditions associated with non-isolation of faults which are a failure to meet license conditions

List below the short list of those options which have been costed within this CBA workbook

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	Baseline	Rejected							
2	Do Nothing	Rejected	Financial / Customer impact of no investment - Included for comparion only		-£9.51	-£15.12	-£21.68	-£27.09	
3	Proactive Scenario	Adopted	Most economic option		£0.57	£1.22	£1.98	£3.44	
3.1	Sensitivity to degradation and repair rates		10% increase in pilot failures per annum		-£0.20	-£0.27	-£0.31	-£0.31	
3.2	Sensitivity to degradation and repair rates and reduced repair rates		10% increase in failures plus 5% reduction in repair rates		-£0.56	-£0.97	-£1.40	-£2.09	
4	Monitoring Scenario	Rejected	Least economic option		-£0.06	£0.51	£1.25	£2.73	

Investment Business Case

CBA No.	10
Scheme/Project Name	HV Pole Replacement
Scheme/Project Owner	Peter Sherwood
Primary Investment Objective	To determine the optimum method of replacing HI5 wood poles
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
1	Baseline	Rejected
2	Replace the decayed poles using live line techniques.	Adopted
3	Replace the decayed poles under an outage but install generators to prevent customers from going off supply	Rejected

Background & Justification

To determine the optimum method of replacing HI5 wood poles.

Approach to the Options Appraisal

- *Option 1 is always a 'do minimum'/ Business as usual Option. All the costs and benefits associated with the other options are relative to the do minimum Option (Option 1).*
- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline/Option 1)

It has been assumed that the contractors will be able to change 6 poles in a 5 hour outage. This is obviously dependant on the number of linesmen deployed to the circuit.

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*
Option 2 - Replace the decayed poles using live line techniques.

It has been assumed that a Rubber Glove Live Line team consists of 3 linesmen and will replace 2 poles per day.

Term (years from first out flow)	NPV (£m)
16	£4.48
24	£5.04
32	£5.42
45	£5.82
first year of investment out flow	1

Where the individual project is technically compliant with the Live Line Working Safety Case, replacing poles live line is the most economic method of carrying out the work.

Option 3: - Replace the decayed poles under an outage but install generators to prevent customers from going off supply

Term (years from first out flow)	NPV (£m)
16	-£0.61
24	-£1.46
32	-£2.03
45	-£2.62
first year of investment out flow	1

Although politically adventageous, it is not cost effective to install generators to prevent customers going off supply.

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Option 1 Baseline scenario: replace the decayed poles under an outage.	It has been assumed that the contractors will be able to change 6 poles in a 5 hour outage. This is obviously dependant on the number of linesmen deployed to the circuit.
Option 2 Replace the decayed poles using live line techniques.	It has been assumed that a Rubber Glove Live Line team consists of 3 linesmen and will replace 2 poles per day.
Option 3 Replace the decayed poles under an outage but install generators to prevent customers from going off supply	

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	Baseline	Rejected	Replace the decayed poles under an outage.		£0.00	£0.00	£0.00	£0.00	
2	Replace the decayed poles using live line techniques.	Adopted	Where the individual project is technically compliant with the Live Line Working Safety Case, replacing poles live line is the most economic method of carrying out the work.		£4.48	£5.04	£5.42	£5.82	
3	Replace the decayed poles under an outage but install generators to prevent customers from going off supply	Rejected	Although politically adventageous, it is not cost effective to install generators to prevent customers going off supply.		-£0.61	-£1.46	-£2.03	-£2.62	

Investment Business Case

CBA No.	11
Scheme/Project Name	Service Position Modernisation
Scheme/Project Owner	Dave Kilday
Primary Investment Objective	To optimise the replacement cut-outs and service cables in light of future increasing load.
Secondary Investment Objective (Engineering)	Replace HI5 cut-outs and service cables.

Option no.	Options considered	Decision
1 (Baseline)	Replace HI5 poor condition cut-outs and service cables, like for like, and then replace these services and cut-outs as future increases in load due to heat pumps etc come on stream.	Adopted
2	Replace HI5 poor condition cut-outs only, service cables will be repaired on failure. Services and cut-outs will be replaced as future increases in load due to heat pumps etc come on stream.	Rejected
3	Replace HI5 poor condition cut-outs and upgrade the HI5 service cables to future proof the services against increases in load due to heat pumps etc.	Rejected

Background & Justification

We have a large programme of works to assess and rectify all end of life cable heads by the end of RIIO-ED1. As a consequence of visiting the properties to rectify the health of the cable head, the health of the service cable will also be assessed. A number of these service cables will also be end of life.

Business as Usual Option (Baseline/Option 1)

Replace HI5 poor condition cut-outs and service cables, like for like, and then replace these services and cut-outs as future increases in load due to heat pumps etc come on stream.

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*
We have chosen to adopt our baseline strategy (Option 1). Although there is a financial advantage to allowing the service cables to fail (Option 2), there is a customer expectation that, when carrying out work inside their homes, we will not leave poor condition assets to fail. Failure after a few years of "modernising" their equipment is seen as being poor customer service and not acceptable.

Approach to the Options Appraisal

- *Option 1 is always a 'do minimum'/ Business as usual Option. All the costs and benefits associated with the other options are relative to the do minimum Option (Option 1).*
- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

1. We can replace the end of life service cable at the same time as the end of life cable head.
2. We can only replace the end of life cable head and allow the service cable to fail at some point in the relatively near future.
3. We can take the opportunity to upgrade the service and the cable head to facilitate the uptake of low carbon technology at some point in the future.

Option 2:
Replace end of life cable heads only, service cables will be repaired on failure. Services and cable head will be replaced as future increases in load due to heat pumps etc come on stream. While this option is financially advantageous, it is poor customer service to rectify one end of life component in a customer’s house and leave another component to fail within a few years. In addition, due to the location of the service cable within the house, if the cable fails at the termination and that termination is packed with flammable material belonging to the customer, then there good chance that our equipment may cause a fire within the customer’s property. It is, therefore, unacceptable to walk away from the property and leave this scenario.

Term (years from first out flow)	NPV (£m)
16	£0.97
24	£1.12
32	£1.22
45	£1.31
first year of investment out flow	1

Option 3:

Replace end of life cable heads and upgrade the end of life service cables to future proof the services against increases in load due to the uptake of low carbon technology. As it is unknown whether or not the load at an individual property will increase, a scatter gun approach of upgrading end of life services is not cost effective.

Term (years from first out flow)	NPV (£m)
16	-£0.24
24	-£0.45
32	-£0.58
45	-£0.72
first year of investment out flow	1

Sensitivities

N/A

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Option 1 (Baseline)	Replace HI5 poor condition cut-outs and service cables, like for like, and then replace these services and cut-outs as future increases in load due to heat pumps etc come on stream.
Option 2	Replace HI5 poor condition cut-outs only, service cables will be repaired on failure. Services and cut-outs will be replaced as future increases in load due to heat pumps etc come on stream.
Option 3	Replace HI5 poor condition cut-outs and upgrade the HI5 service cables to future proof the services against increases in load due to heat pumps etc.

List below the short list of those options which have been costed within this CBA workbook

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	Replace HI5 poor condition cut-outs and services.	Adopted			£0.00	£0.00	£0.00	£0.00	
2	Replace HI5 poor condition cut-outs only.	Rejected	Rejected due to customer service and safety implication.		£0.97	£1.12	£1.22	£1.31	
3	Upgrade HI5 poor condition cut-outs and service cables	Rejected	Rejected due to negative NPV		-£0.24	-£0.45	-£0.58	-£0.72	

Investment Business Case

CBA No	12
Scheme/Project Name	LV OHL Village Modernisation
Scheme/Project Owner	Paul Butter
Primary Investment Objective	To replace ageing LV network in Villages and improve fault performance for customers
Secondary Investment Objective (Engineering)	Remove Health Index 5 assets (end of life) and remove areas of network that are non-compliant with the Electricity Safety, Quality and Continuity Regulations (ESQCR)

Option no.	Options considered	Decision
1 (Baseline)	Overhead line with 8% UG	Adopted
2	Overhead line - Increased conductor size for Future Load	Rejected
3	Underground Cable (185 waveform)	Rejected
4	Underground - Combination of Increased conductor size and U/G cable	Rejected

Background & Justification

In some villages the LV overhead line network is at its end of life (Health Index 5) and therefore in need of replacement. The current condition of the LV overhead line assets is resulting in high fault rates on some circuits, causing customers to experience ‘power cuts’. These higher fault rates also result in financial penalties for SPEN, through customer minutes lost (CML) and customer interruptions (CI) penalties. In addition to CI/CML penalties, the fault repair cost must be incurred by SPEN to cover labour and materials

The wooden poles in some areas of the LV overhead line network are rotten and cannot be climbed safely by our linesman. This is also resulting in longer fault durations, as other methods to access the line, such as MEWP (mobile elevated work platforms), must be used. These rotten wood poles also present a great risk in storm conditions, where there is an increased danger of high winds grounding the poles. Grounded lines will result in long outages for customers, especially post storm, when resources could be being used elsewhere.

There is also an argument that the increased fault rate, due to the poor condition of assets, is a contributing factor to the penalties received through the ‘Broader customer service initiative’

It has also been found, that in areas, the LV overhead line network is non compliant with the Electricity Safety, Quality and Continuity Regulations compliant due to low ground clearance issues. The ESQCR regulations state that the minimum height above ground for overhead lines must be 5.2m (5.8m above roads). It is critical that these areas of network are replaced to ensure the ESQCR regulations are complied with.

Our policy for LV underground cables is based on a strategy to reduce customer interruptions by replacing cables with operational restrictions. The condition of underground cable assets cannot be easily accessed and the failure rates experienced to date don’t suggest a need for replacement on a large scale, and our replacement plans reflect a continued steady investment. There are however, particular types of cable that are exhibiting problems which we will continue to replace. This raises the questioning of how beneficial undergrounding is overall when taking the above into consideration.

Installation of underground cables can cause disruption and inconvenience to customers and a large proportion of the cost is associated with excavation. Stakeholders provided support for an element of future proofing by taking the opportunity to install a larger cable with higher capacity on the LV network when carrying out replacement activity. Within the SPM network area this will require careful consideration on the interconnected LV network. Having taken into both options it is immediately obvious that overhead lines will be the most viable option financially.

Business as Usual Option (Baseline/Option 1)

Our baseline scenario is to use 92% overhead line and 8% of underground cable.

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*

We have adopted our baseline scenario as this will return the best NPV by a considerable amount.

Approach to the Options Appraisal

- *Option 1 is always a 'do minimum'/ Business as usual Option. All the costs and benefits associated with the other options are relative to the do minimum Option (Option 1).*
- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

In order to mitigate the effect of aging LV network, we plan to modernise 4% of the total LV network per annum in ED-1 (391.3km per annum. 3130km in ED-1). The proportion of this 4% per annum that attributed to overhead line and cable is reflected in the four options.

The four options considered are:
- Replace proportionately 92% with ABC and 8% underground cable
- Replace 92% with larger conductor ABC and 8% underground cable
- Replace with 100% underground cable
- 74% ABC and 26% underground (in areas with load growth)

The decision to replace the LV overhead line assets with bare wire conductor was rejected, without a cost benefit analysis, on grounds of safety. The option of using an insulated conductor (ABC) was considered instead, as this reduces the risk to public safety. ABC also provides a lower transient and permanent fault rate than bare wire as it is resilient against conductor clashing and tree damage.

There are various factors considered to come to the conclusion on the correct option to adopt. There was consideration in terms of:

- Fault Rate (CI /CML and labour)
- Capital Cost
- Cost of Service Cable
- Damage Compensation Claims (service cables)
- Visual Impact
- Inspection Costs
- Tree Cutting Costs
- Maintenance and Refurbishment costs
- Asset Deterioration (assumed linear)

The summary of the cost-benefit analysis options with associated NPV (relative to the baseline) is shown below. The option with the least negative NPV was chosen, in this case the baseline.

Options Summary

Baseline – 92% ABC with 8% Underground Cable
The baseline case (option 1) is to replace, where possible, the LV network in villages with ABC using like for like sizes of conductor. In cases where ABC is not feasible 185mm waveform cable will be used (8%).

Total SPEN Volumes (ED-1):
50mm2 ABC (single phase) – 1595 km
50mm2 ABC (3 phase) – 712 km

95mm2 ABC (3 phase) –541 km
120mm2 ABC (3phase) – 0 km
185mm2 waveform U/G cable – 282 km

Volumes per annum
ABC – 356 km/year
Underground cable – 35.3km/year

Option 2 – 92 % ABC with larger conductors (future proofing)
Option two is to use the same percentage of cable and overhead line as the baseline, but use a larger size of conductor to future proof the network against load growth.

Total SPEN Volumes (ED-1)
50mm2 ABC (single phase) – 0 km
50mm2 ABC (3 phase) – 0 km
95mm2 ABC (3 phase) –2307 km
120mm2 ABC (3phase) – 541 km
185mm2 waveform U/G cable – 282 km

Volumes per annum
ABC – 356km/year
Underground cable – 35.3km/year

Term (years from first out flow)	NPV (£m)
16	-£1.16
24	-£1.48
32	-£1.69
45	-£1.91
first year of investment out flow	1

Option 3 – All U/G

Option 3 is to replace with 100% underground cable (185mm waveform)

Total SPEN Volumes (ED-1):
50mm2 ABC (single phase) – 0 km
50mm2 ABC (3 phase) – 0 km
95mm2 ABC (3 phase) –0km
120mm2 ABC (3phase) – 0 km
185mm2 waveform U/G cable – 3130 km

Volumes per annum
ABC – 0km/year
Underground cable – 391.3 km/year

Term (years from first out flow)	NPV (£m)
16	-£67.73
24	-£86.53
32	-£98.66
45	-£109.59
first year of investment out flow	1

Option 4 – 74% ABC and 26% underground (in areas with load growth)

Option 4 is similar to the option 2 (future proof), but the 541 km of 120mm ABC are undergrounded instead.

Total SPEN Volumes:
50mm2 ABC (single phase) – 0 km
50mm2 ABC (3 phase) – 0 km
95mm2 ABC (3 phase) – 2307 km
120mm2 ABC (3phase) – 0 km
185mm2 waveform U/G cable – 823 km

Volumes per annum
ABC – 288.3km/year
Underground cable – 102.9 km/year

Term (years from first out flow)	NPV (£m)
16	-£13.77
24	-£17.59
32	-£20.06
45	-£22.31
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Attach CBA spreadsheet here =➔

Options considered	Comment
Baseline Scenario	50/95mm2 ABC with 8% UG
Overhead line - Increased conductor size for Future Load	50mm inceased to 95mm. 95mm increased to 120mm
Underground Cable (185 waveform)	All investment in 185mm Cable
Underground - Combination of Increased conductor size and U/G cable	95mm ABC with U/G cable
Bare Wire option	Unacceptable to erect new uninsulated overhead conductor (LV). No cost benefit analysis required

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	Baseline- Overhead line with 8% UG	Adopted			£0.00	£0.00	£0.00	£0.00	
2	Overhead line - Increased conductor size for Future Load	Rejected	Rejected due to negative NPV		-£1.16	-£1.48	-£1.69	-£1.91	
3	Underground Cable (185 waveform)	Rejected	Rejected due to negative NPV		-£67.73	-£86.53	-£98.66	-£109.59	
4	Underground - Combination of Increased conductor size and U/G cable	Rejected	Rejected due to negative NPV		-£13.77	-£17.59	-£20.06	-£22.31	

Investment Business Case

CBA No.	13
Scheme/Project Name	Whitchurch
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Increase supply security and facilitate demand growth
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	To establish a 132kV Grid in-feed at Wem substation.	Adopted
1	To establish a additional 132kV Grid in-feed at Whitchurch Grid substation and increase 33kV connectivity.	Rejected
2	To change Oswestry Grid transformer and increase 33kV connectivity.	Rejected

Background & Justification

Strategic investment in the electricity distribution system in Shropshire in order to increase supply security and facilitate economic growth of the local area.

The 33kV system in Whitchurch and the surrounding area of Shropshire is currently operating at maximum thermal and voltage limits. There is a grid transformer that feeds this area of the system via three very long 33kV overhead lines that normally operate interconnected with three adjacent 33kV substation groups. Through stakeholder engagement with the local county council it has been identified that there are significant development plans for the Whitchurch area and concerns are continually being raised about the lack of existing capacity headroom inhibiting growth and development. The options listed below take consideration of growth supported by the council in relation to their development plans, as well as the wider 33kV system requirements and 'SPM Best View Scenario' for capacity based on WS3 analysis. In order to comply with section 9 of the Electricity Act and Condition 21 of our distribution license obligation “to develop and maintain an efficient, coordinated and economical system for the distribution of electricity” an enduring design solution is required in order to satisfy the existing demand requirements and accommodate future load growth. A full range of smart solutions have been considered as outlined below, with load transfer being a smart option that would provide a limited level of load growth in the short term. Assessments at this stage have indicated this smart solution will not negate or allow the conventional solution to be deferred, due to the additional capacity requirement and very limited thermal/voltage capability of the existing system. However, it is anticipated that as an interim solution this smart option may facilitate some limited load growth in the local area during the planning of the Baseline Scenario, which is anticipated to take a number of years to deliver due to the associated planning and consenting requirements. During the planning of the 132kV overhead line associated with the Baseline Scenario it is proposed that a technical assessment of the system will be completed on a annual basis and full consideration will be given to the need case at that time and emerging smart solutions that may provide the opportunity to defer investment in the conventional reinforcement. The operational expenditure associated with the options in the short list have been excluded from the CBA as they are of a similar order of magnitude and are not considered to be material when compared to the overall investment.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

<u>**Business as Usual Option (Baseline) -** establish a 132kV Grid in-feed at Wem substation fed from Oswestry – **Option Chosen**</u>

The Baseline Scenario is to install a Grid Transformer at Wem substation and a 132kV circuit from Oswestry Grid. Installing a Grid Transformer at Wem will provide a grid in-feed at a midway point into two very long 33kV ccts between Oswestry and Whitchurch grid substations. The Baseline Scenario is the natural solution to the thermal/voltage issues, as support at Wem is what's needed. Initial studies indicate the proposal will cater for general load growth and the proposed new demand at Whitchurch. This option is dependant on a previously authorised project to install a 132kV circuit between Legacy and Oswestry and is currently awaiting the outcome of a public enquiary. This dependency can be negated by connecting at different location on the 132kV system, however, this would increase the costs due to the increased 132kV circuit length. This option will result in a potential cost saving of approximately £1.2m on the future asset replacement program as the Wem 33kV switchboard will be replaced as part of the works.

<u>Option 1 - establish a additional 132kV Grid in-feed at Whitchurch Grid substation and increase 33kV connectivity.</u>

Option 1 is to install a additional Grid Transformer at Whitchurch, a 132kV circuit from Marchwiel Grid and a new 33kV circuit between Wem and Whitchurch Grid. Whitchurch 33kV switchboard asset replacement is required in ED1 and therefore this option will result in a potential cost saving of approximately £1.8m on the proposed ED1 asset replacement program. With the installation of a grid transformer at Whitchurch the two 33kV ccts between Oswestry and Whitchurch will operate at thermal limits and therefore it is necessary to increase 33kV connectivity with this part of the system. Initial studies indicate this option will cater for general load growth and significant demand growth at Whitchurch, however, parts of the surrounding 33kV network will continue to operate towards statutory voltage limits during outage conditions.

Term (years from first out flow)	NPV (£m)
16	-£1.48
24	-£2.12
32	-£2.55
45	-£3.01
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to establish a 132kV Grid in-feed at Wem substation fed from Oswestry.	The Baseline Scenario is to install a Grid Transformer at Wem substation and a 132kV circuit from Oswestry Grid. Installing a Grid Transformer at Wem will provide a grid in-feed at a midway point into two very long 33kV ccts between Oswestry and Whitchurch grid substations. The Baseline Scenario is the natural solution to the thermal/voltage issues, as support at Wem is what's needed. Initial studies indicate the proposal will cater for general load growth and the proposed new demand at Whitchurch. This option is dependant on a previously authorised project to install a 132kV circuit between Legacy and Oswestry and is currently awaiting the outcome of a public enquiary. This dependency can be negated by connecting at different location on the 132kV system, however, this would increase the costs due to the increased 132kV circuit length. This option will result in a potential cost saving of approximately £1.2m on the future asset replacement program as the Wem 33kV switchboard will be replaced as part of the works.
Option 1 to establish a additional 132kV Grid in-feed at Whitchurch Grid substation and increase 33kV connectivity.	Option 1 is to install a additional Grid Transformer at Whitchurch, a 132kV circuit from Marchwiel Grid and a new 33kV circuit between Wem and Whitchurch Grid. Whitchurch 33kV switchboard asset replacement is required in ED1 and therefore this option will result in a potential cost saving of approximately £1.8m on the proposed ED1 asset replacement program. With the installation of a grid transformer at Whitchurch the two 33kV ccts between Oswestry and Whitchurch will operate at thermal limits and therefore it is necessary to increase 33kV connectivity with this part of the system. Initial studies indicate this option will cater for general load growth and significant demand growth at Whitchurch, however, parts of the surrounding 33kV network will continue to operate towards statutory voltage limits during outage conditions.
Option 2 is to change Oswestry Grid transformer and increase 33kV connectivity.	This option is to change a grid transformer at Oswestry Grid, to install a 33kV cct between Oswestry and Wem, to install two 33kV ccts between Marchwiel and Whitchurch and to reconductor a 33kV cct between Marchwiel and Duckington. Initial studies indicate the proposal will cater for general load growth and limited new demand at Whitchurch. This option is not ideal as it will significantly increase 33kV connectivity between multiple substation groups, that may present operational issues, with increased risk of cascade tripping for system faults and reduction in 33kV fault level headroom in the adjacent groups.
To establish a 132kV Grid in-feed at Wem substation fed from Legacy.	To install a Grid Transformer at Wem substation and 132kV circuit from Legacy Grid. This option has been discounted based on the increased environmental impact and cost due to the greater 132kV cct distance when compared with Baseline Scenario.
To establish a 132kV Grid in-feed at Wem substation fed from Marchwiel.	To install a Grid Transformer at Wem substation and 132kV circuit from Marchwiel Grid. This option has also been discounted based on the increased environmental impact and cost due to the greater 132kV cct distance when compared with Baseline Scenario.
To install a GT and PST at Whitchurch and to increase 33kV connectivity.	This option is to install a additional Grid Transformer, 33kV switchboard and a 33kV Phase Shift Transformer at Whitchurch Grid substation. A new 33kV circuit between Wem and Whitchurch Grid would also be needed. With this option the new grid transformer would be connected via a 33kV Phase Shift Transformer that would be connected at 132kV from a existing 132kV circuit that is fed from the adjacent supergrid group. There are potential operational issues associated with this option due to impact on adjacent parts of the system and therefore this option has been initially discounted. The use of Phase Shift Transformers is also a new concept in terms of the SP Manweb as they have not previously been utilised. There is a LCNF project that will incorporate a Phase Shift Transformer and based on the experience from this project further more detailed consideration will be given to this option being progressed.
To install a Automatic Load Transfer scheme (Smart Solution)	Initial assessments indicate this option will facilitate a very limited level of demand growth and not at the level indicated through our stakeholder engagement. This option has been discounted at this stage, however, it is proposed that it will be utilised in order to facilitate development during the planning of the Baseline Scenario.
To employ a Demand Side Management scheme (Smart Solution)	At present the new customers have not yet been identified, however, they will be consulted as the area develops. This option has been discounted as at present because we don't know enough about future customers to assess the viability of Demand Side Management but this will be explored in the future.
To install a Energy Storage scheme (Smart Solution)	This technology is not yet mature and will be reviewed further as it develops. At present we understand that there are not any installations including trials at the level of capacity required and therefore this option has been discounted based on risk.
Dynamic thermal ratings of existing 33kV circuits (Smart Solution)	Dynamic thermal ratings would provide limited thermal headroom, but would not resolve the voltage issues and therefore voltage regulators would also be required, which indicates a conventional reinforcement solution is more appropriate. As the combination of Dynamic Thermal Ratings and Voltage Regulators would still not accommodate the level of demand indicated through stakeholder engagement this option has been discounted.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	To establish a 132kV Grid in-feed at Wem substation.	Adopted	Both the Baseline Scenario and Option 1 have similar cost, environmental impact and social, economic benefits in terms of the overall system. Therefore the Baseline Scenario has been adopted as internal stakeholder engagement that has also indicated it is the preferred operational arrangement.						
1	To establish a additional 132kV Grid in-feed at Whitchurch Grid substation and increase 33kV connectivity.	Rejected	This option will facilitate economics in non-load program as the 33kV switchboard at Whitchurch would be changed as part of the works. This option has been rejected on the basis of lesser operational benefits and cost when compared with the Baseline Scenario.		-£1.48	-£2.12	-£2.55	-£3.01	
2	To change Oswestry Grid transformer and increase 33kV connectivity.	Rejected	This option has been rejected on the basis that the overall costs are similar to establishing a 132kV grid in feed and as it would present operational difficulties, with limited thermal, voltage and fault level head/leg room when compared with the other options available.		-£0.45	-£0.77	-£0.98	-£1.22	

Investment Business Case

CBA No.	14
Scheme/Project Name	Anglesey
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Increase supply security and facilitate demand growth
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	Baseline scenario to establish a second 132/33kV transformer at Caergeilliog fed from Wylfa	Rejected
1	Option 1 to establish a new GT at Llanfair PG fed from Pentir and to establish a new 33kV circuit between Llangaffo and Llanfair PG	Adopted
2	Option 2 to install a new GT at Llanfair PG fed from Pentir and to establish a new 33kV circuit between Llangaffo and Llanfair PG. To establish a second GT at Caergeilliog fed from Wylfa	Rejected

Background & Justification

Strategic investment in the electricity distribution system in North Wales in order to increase supply security and facilitate growth of demand and generation in the local area.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - establish a second 132/33kV transformer at Caergeilliog fed from Wylfa

Will significantly increase thermal capacity in location of high demand. Will be necessary to maintain 33kV connectivity with the mainland in case of double circuit fault of 400kV tower line feeding Wylfa.
Second GT at Caergeilliog will significantly improve the voltage on Anglesey.
Potential risk of voltage issues at Llanfair PG/Bangor area for n-1 of Bangor as demand increases in that area.

Option 1 - establish a new GT at Llanfair PG fed from Pentir and to establish a new 33kV circuit between Llangaffo and Llanfair PG – **Option Chosen**

Will create a robust independent group of three grid transformers with two 33kV circuits between each substation and will significantly increase thermal capacity. Will provide additional 132kV infeed to Anglesey.
Availability to provide voltage support to Bangor during n-1 outages, however potential voltage issues under n-1 conditions if the demand at Caergeillog grows significantly.
Operating the Anglesey 33kV system independently will facilitate reinforcement of the 33kV system on the mainland within fault level limits.

Term (years from first out flow)	NPV (£m)
16	£0.87
24	£1.13
32	£1.32
45	£1.51
first year of investment out flow	2

Option 2: - Install a new GT at Llanfair PG fed from Pentir and to establish a new 33kV circuit between Llangaffo and Llanfair PG. To establish a second GT at Caergeilliog fed from Wylfa

Robust enduring solution that will provide capacity long term. However, would result in underutilised assets if undertaken too soon or if anticipated demand does not materialise. Baseline or Option 1 could be considered as a first stage toward this enduring solution.

Term (years from first out flow)	NPV (£m)
16	-£7.75
24	-£10.16
32	-£11.81
45	-£13.51
first year of investment out flow	2

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to establish a second 132/33kV transformer at Caergeilliog fed from Wylfa	Will significantly increase thermal capacity in location of high demand. Will be necessary to maintain 33kV connectivity with the mainland in case of double circuit fault of 400kV tower line feeding Wylfa. Second GT at Caergeilliog will significantly improve the voltage on Anglesey. Potential risk of voltage issues at Llanfair PG/Bangor area for n-1 of Bangor as demand increases in that area.
Option 1 to establish a new GT at Llanfair PG fed from Pentir and to establish a new 33kV circuit between Llangaffo and Llanfair PG	Will create a robust independent group of three grid transformers with two 33kV circuits between each substation and will significantly increase thermal capacity. Will provide additional 132kV infeed to Anglesey. Availability to provide voltage support to Bangor during n-1 outages, however potential voltage issues under n-1 conditions if the demand at Caergeillog grows significantly. Operating the Anglesey 33kV system independently will facilitate reinforcement of the 33kV system on the mainland within fault level limits.
Option 2 to install a new GT at Llanfair PG fed from Pentir and to establish a new 33kV circuit between Llangaffo and Llanfair PG. To establish a second GT at Caergeilliog fed from Wylfa	Robust enduring solution that will provide capacity long term. However, would result in underutilised assets if undertaken too soon or if anticipated demand does not materialise. Baseline or Option 1 could be considered as a first stage toward this enduring solution.
Do Nothing	As demand increases the 33kV network may operate outside of the recommendations of ER P2/6. Connecting further generation at 33kV is problematic without voltage stability issues and exceeding upper voltage limits. This option has been rejected.
To establish a second 132/33kV transformer at Caergeilliog fed from new 132kV circuit to a new 132kV substation supplied by a tee-off from an National Grid owned 132kV circuit near Wylfa	This option will significantly increase thermal capacity in the location of high demand and improve the voltage on Anglesey. the is a potential risk of voltage issues at Llanfair PG/Bangor area for n-1 of Bangor as demand increases in that area. This option has been discounted at this stage as the availability of connection to the National Grid circuit is yet to be determined due to other ongoing projects and existing commercial arrangements. This option will continue to be considered and discussed with National Grid to ensure the most economic and optimal engineering solution is progressed.
To change Caergeilliog and Amlwch GTs and establish additional 33kV circuit between Bangor and Llanfair PG.	This option is to Change Caergeilliog and Amlwch GTs from 45MVA to 60MVA units and to establish additional 33kV circuit between Bangor and Llanfair PG substations. This option would only provide a limited increase in thermal capacity and would not adequately resolve the voltage (upper/lower/stability) issues associated with the increasing levels of generation in the area. This option has been rejected as it does not adequately mitigate voltage issues or provide sufficient thermal headroom to accommodate forecast ED1 demand/generation growth.
To install Static VAR compensation on Anglesey the 33kV network (Smart Solution)	To install capacitor banks on the 33kV network on Anglesey to flatten the voltage profile and facilitate connection of more generation. This option has been rejected as it would not mitigate thermal issues and could potentially introduce instability into the automatic voltage control scheme on the proposed in-line regulator near Amlwch.
To install 33kV inline regulators in key circuits on Anglesey (Smart Solution)	To install in-line regulators on the 33kV network on Anglesey to improve the voltage profile and facilitate connection of more demand/generation. This option has been rejected as it would not mitigate thermal issues and could potentially introduce instability into the automatic voltage control scheme on the proposed in-line regulator near Amlwch. Connection of significant levels of generation could intorduce instability into the AVC of the 132/33kV transformers in the group.
To install a Dynamic Thermal Rating scheme (Smart Solution)	Install real time thermal rating equipment on key 33kV assets on Anglesey. This would potentially manage the thermal constraints on these circuits. This option has been rejected as it would not mitigate the voltage constraints or facilitate connection of new generation.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	Baseline scenario to establish a second 132/33kV transformer at Caergeilliog fed from Wylfa	Rejected							
1	Option 1 to establish a new GT at Llanfair PG fed from Pentir and to establish a new 33kV circuit between Llangaffo and Llanfair PG	Adopted	Both the Baseline Scenario and Option 1 have similar cost, environmental impact and social, economic benefits in terms of the overall system. Option 1 has been adopted as internal stakeholder engagement that has also indicated it is the preferred operational arrangement and it is the minimum overall cost.		£0.87	£1.13	£1.32	£1.51	
2	Option 2 to install a new GT at Llanfair PG fed from Pentir and to establish a new 33kV circuit between Llangaffo and Llanfair PG. To establish a second GT at Caergeilliog fed from Wylfa	Rejected	Rejected based on cost.		-£7.75	-£7.75	-£7.75	-£7.75	

Investment Business Case

CBA No.	15
Scheme/Project Name	Birkenhead
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Increase supply security and facilitate demand growth
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	To establish a new 132kV circuit between Woodside grid and Birkenhead grid	Adopted
1	To establish a new 132/33kV substation located in the Birkenhead dockland area and to loop it into the new 132kV circuit.	Rejected

Background & Justification

Strategic investment in the electricity distribution system in Birkenhead in order to increase supply security and load growth in the local area.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - establish a new 132kV circuit between Woodside grid and Birkenhead grid– **Option Chosen**

- The new circuit would secure the supplies to the group whilst providing significant headroom for new demand for the foreseeable future whilst at the same time maintaing Licence obligations under P2/6.
- This option also facilitates but does not provide for further demand growth in the docklands area though future addition of a 132/33kV transformer

Option 1 - establish a new 132/33kV substation located in the Birkenhead dockland area and to loop it into the new 132kV circuit.

Term (years from first out flow)	NPV (£m)
16	-£2.74
24	-£3.44
32	-£3.95
45	-£4.44
first year of investment out flow	6

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to establish a new 132kV circuit between Woodside grid and Birkenhead grid.	- The new circuit would secure the supplies to the group whilst providing significant headroom for new demand for the foreseeable future whilst at the same time maintaing Licence obligations under P2/6. - This option also facilitates but does not provide for further demand growth in the docklands area though future addition of a 132/33kV transformer
Option 1 to establish a new 132/33kV substation located in the Birkenhead dockland area and to loop it into the new 132kV circuit.	- The new 132kV circuit would secure the supplies to the group whilst providing significant headroom for new demand - The new 132/33kV substation would address the group's 33kV demand increase requirements within the Birkenhead area. - The local 33kV network would be reconfigured and connected onto a new 33kV switchboard established at the site to provide support to the existing group and to accommodate any new demand requirements. - This option would provide headroom for further demand growth in the docklands area
To establish automated load transfer scheme (Smart Solution)	Internal stakeholder engagement suggests that delivery of this option would be complex. Introduction of 132kV intertripping at Brombrough to supply areas of the 33kV network from the adjacent Capenhurst GSP would introduce interlinking of the GSPs through the 33kV network. This option has been rejected at this stage due to technical risk.
To employ a Demand Side Management scheme (Smart Solution)	At present the new customers have not yet been identified, however, they will be consulted as the area develops. This option has been discounted as at present because we don't know enough about future customers to assess the viability of Demand Side Management but this will be explored in the future.
Dynamic thermal ratings of existing assets (Smart Solution)	Dynamic thermal ratings is not expected to provide sufficient thermal headroom for when the group grows to become a ER P2/6 Class E group. It would not be expected to secure supplies under moderate demand growth. This option has been rejected at this stage due to technical risk, however it may be expored in more detail in future as demand growth is monitored.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	To establish a new 132kV circuit between Woodside grid and Birkenhead grid	Adopted	The new circuit would secure the supplies to the group for the duration of ED1						
1	To establish a new 132/33kV substation located in the Birkenhead dockland area and to loop it into the new 132kV circuit.	Rejected	- Robust Enduring solution which adequetly addresses security of supply issues. - Would result in underutilised assets if anticipated future demand in the docklands area does not materialise. - Rejected on cost. Baseline solution can be used as a first stage toward this enduring solution.		-£2.74	-£3.44	-£3.95	-£4.44	

Investment Business Case

CBA No.	16
Scheme/Project Name	Elworth, Hartford, Knutsford, Lostock
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Accomodate future growth
Secondary Investment Objective (Engineering)	

Option no.	Decision
Baseline	Adopted
I	Rejected

Background & Justification

Strategic investment in the electricity distribution system in the Lostock area in order to satisfy the existing demand requirements and accommodate future load growth.

The network under consideration is the Elworth GT1, Elworth GT2, Hartford, Knutsford GT1, Knutsford GT2, Lostock 33kV demand group that predominantly consists of 45MVA GTs. Figure 1 shows the existing 33kV configuration.

One of the main constraints associated with the 33kV group relates to limitations due to geographical configuration of transformer capacity in relation to load and 56MW of generation connected to the 33kV switchboard at Elworth Grid substation. Studies indicate circuit power flows from Elworth Grid approach circuit ratings and can be particularly excessive during n-1 outage conditions.

Studies have highlighted thermal issues associated with the forecast ED1 demand growth and therefore it is proposed to undertake reinforcement as outlined in this paper.

In order to comply with section 9 of the Electricity Act and Condition 21 of our license obligation "to develop and maintain an efficient, coordinated and economical system for the distribution of electricity" an enduring design solution is required in order to satisfy the existing demand requirements and accommodate future load growth and this proposal will meet that requirement. . The approach suggested here will meet that requirement.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

<u>**Business as Usual Option (Baseline) -** install an additional GT at Winsford grid and split the 33 kV system into two separate groups. It is also proposed to establish an additional circuit between Hartford and Lostock grid – **Option Chosen**</u>

The Baseline Scenario to resolve the thermal issues identified and to accommodate future load growth is to install an additional GT at Winsford grid and to split the 33kV system into two separate groups. It is also proposed to establish an additional circuit between Hartford and Lostock grid. Studies indicate that Winsford grid is the most appropriate location for an additional grid transformer as it is situated in the middle of a large industrial estate in the centre of much of the group demand. Studies also indicate that the only viable option to cater for the forecast ED1 demand growth is to split the 33kV group and in order to achieve this additional grid transformer capacity is required.

<u>Option 1 - install an additional GT at Hartford grid</u>

The configuration of the existing 132 kV network would make it less costly to install an additional GT at Hartford Grid. However, due to the geographical location it is not an ideal location for an additional transformer and would not resolve all the thermal issues without installing two additional 33kV circuits between Hartford and Winsford.

Term (years from first out flow)	NPV (£m)
16	-£3.01
24	-£3.65
32	-£4.08
45	-£4.51
first year of investment out flow	1

Option 2: - To install a Automatic Load Transfer scheme

Initial assessments indicate this option will facilitate a very limited level of demand growth and not at the level indicated through our stakeholder engagement. This option has been discounted at this stage, however, it is proposed that it will be utilised in order to facilitate development during the planning of the Baseline Scenario.

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to install an additional GT at Winsford grid and split the 33 kV system into two separate groups. It is also proposed to establish an additional circuit between Hartford and Lostock grid.	The Baseline Scenario is to install an additional GT at Winsford grid and split the 33 kV system into two separate groups in order to resolve the thermal issues. It is also proposed to establish an additional circuit between Hartford and Lostock grid. Studies indicate that Winsford grid is the most appropriate location for an additional grid transformer as it is situated in the middle of a large industrial estate in the centre of much of the group demand. Studies also indicate that only viable option to resolve the generation push from Elworth is to split the 33 kV group and in order to achieve this additional grid transformer capacity is required. The two reactors in the circuit between Winsford and Elworth will allow the split points between the groups to be closed and for fault level limits to be maintained for n-1 outage conditions during summer maintenance demand and will therefore provide additional supply security in the overall group
Option 1 is to install an additional GT at Hartford grid	The configuration of the existing 132 kV network would make it less costly to install an additional GT at Hartford Grid. However, due to the geographical location it is not an ideal location for an additional transformer and would not resolve all the thermal issues without installing two additional 33kV circuits between Hartford and Winsford.
To install a Automatic Load Transfer scheme (Smart Solution)	Initial assessments indicate this option will facilitate a very limited level of demand growth and not at the level indicated through our stakeholder engagement. This option has been discounted at this stage, however, it is proposed that it will be utilised in order to facilitate development during the planning of the Baseline Scenario.

Option no.	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
				16 years	24 years	32 years	45 years	DNO view
Baseline	Adopted	This option has been adopted because it resolves the issue at a lower cost						
1	Rejected	This option has been rejected because the cost is higher		-£3.01	-£3.65	-£4.08	-£4.51	

Investment Business Case

CBA No.	18
Scheme/Project Name	Brymba Hawarden
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Satisfy existing demand and accomdate future growth
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	replace existing 33 kV indoor boards, A Board and B Board at West George Street GSP	Adopted
1	to replace existing 33 kV indoor boards at West George Street GSP with new boards built offline.	Rejected

Background & Justification

Investment in the electricity distribution system in the Flint area in order to satisfy the existing demand requirements and accommodate future load growth.

The Flint area of the Brymbo / Hawarden / Holywell 33 kV interconnected grid group is forecasted to suffer from both circuit overloads and voltage outsides of statutory for various outage scenarios going forward. Several proposals have been put forward in past however none resolve all scenarios and an enduring design solution is required in order to satisfy the existing demand requirements and accomodate future load growth. These includes crossing circuits at Hawarden Grid 33kV, move load out of the group into an adjacent one, reinforcement by installing additinal 33kV circuit and reinforcement by install static var compensator. In order to resolve the thermal and low voltage issues identified and to accomodate future load growth, it is proposed to establish a grid infeed into the Flint area. This approach will resolve the thermal and voltage issues.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - establish a grid infeed into the Flint area – **Option Chosen**

The Baseline Scenario is to establish a grid infeed into the Flint area. Flint primary with its relatively large point load is electrically ideal for the location of a 132/33kV grid infeed. A suitable 132kV circuit (Connahs Quay A to St Asaph) is within 1.6km and there is sufficient density of 33kV circuits to adequately utilise the grid transformer's capacity. A 132/33kV injection at Flint would cure all of the low voltage and thermal issues in the group. Fault levels at Flint primary would rise above the switchgear rating forcing replacement of the switchgear or fault level limiting measures. The existing Flint primary substation is also within a flood plain and an alternative suitable plot of land would have to be sought. Estimated costs are in the region of £6.3m and include works associated with flood mitigation of the proposal site.

Option 1 - move demand out of the group and to cross feeder circuits at Hawarden Grid

This would involve moving the point demand of the North Wales Paper Mill customer into the Deeside Grid group. This requires an additional Primary substation to keep the remaining HV supplies within the Brymbo-Hawarden-Holywell group. This is expected to resolve the circuit overloads in the group. Moving the load requires length 33kV circuits, a river crossing
Swapping of four circuits at Hawarden Grid to opposite bars is expected to solve the Hawarden Grid busbar fault/outage low voltage problems.

Term (years from first out flow)	NPV (£m)
16	-£0.14
24	-£0.17
32	-£0.20
45	-£0.22
first year of investment out flow	5

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to establish a grid infeed into the Flint area	The Baseline Scenario is to establish a grid infeed into the Flint area. Flint primary with its relatively large point load is electrically ideal for the location of a 132/33kV grid infeed. A suitable 132kV circuit (Connahs Quay A to St Asaph) is within 1.6km and there is sufficient density of 33kV circuits to adequately utilise the grid transformer's capacity. A 132/33kV injection at Flint would cure all of the low voltage and thermal issues in the group. Fault levels at Flint primary would rise above the switchgear rating forcing replacement of the switchgear or fault level limiting measures. The existing Flint primary substation is also within a flood plain and an alternative suitable plot of land would have to be sought. Estimated costs are in the region of £6.3m and include works associated with flood mitigation of the proposal site.
Option 1 to move demand out of the group and to cross feeder circuits at Hawarden Grid	This would involve moving the point demand of the North Wales Paper Mill customer into the Deeside Grid group. This requires an additional Primary substation to keep the remaining HV supplies within the Brymbo-Hawarden-Holywell group. This is expected to resolve the circuit overloads in the group. Moving the load requires length 33kV circuits, a river crossing Swapping of four circuits at Hawarden Grid to opposite bars is expected to solve the Hawarden Grid busbar fault/outage low voltage problems.
No reinforcement	In order for this option to be effective, the Brymbo / Hawarden / Holywell grid group demand would have reduced to around 65% of present winter peak before all of the low voltage issues in the group are no longer of concern. This is considered unlikely.
to move demand out of the group	Moving load out of the group (for example North Wales Paper Mill 9MVA) helps for some scenarios but not all. A winter Hawarden busbar fault and a N-2 outages (Holywell to Greenfield & Holywell to Flint) still creates low voltage as low as 0.933pu. This may also involve significant HV reconfiguration depending on whether a 33kV or HV cable solution was used. This scheme has been rejected as it does not completely resolve the issues.
to install static VAr compensation (Smart Solution)	The installation of static VAr compensation can only maintain statutory volts static but it does not attend to the overload issues associated with a winter Hawarden busbar outage/fault. The estimated cost for this option is £2m. This scheme has been rejected as it does not completely resolve the issues.
to install additional 33kV circuit	An additional 33kV circuit from either Holywell and from Harwarden grid substations would alleviate the low voltage issues assocated with winter N-1 or summer maintenance period N-2 scenarios. However the voltage at Flint and Woodfield Ave still falls close to statutory limits. The estimated cost for this option is £3m - £5m. This scheme has been rejected as it does not completely resolve the issues.
Dynamic thermal ratings of existing 33kV circuits (Smart Solution)	Dynamic thermal ratings would provide limited thermal headroom, but would not resolve the voltage issues and therefore voltage regulators would also be required, which indicates a conventional reinforcement solution is more appropriate. As the combination of Dynamic Thermal Ratings and Voltage Regulators would still not accommodate the level of demand indicated through stakeholder engagement this option has been discounted.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	To establish a 132kV grid infeed into the Flint area	Adopted	This is the most straight forward and cost effective option which is able to resolve both thermal and voltage issues. Therefore this option is adopted.						
1	to move demand out of the group and to cross feeder circuits at Hawarden Grid	Rejected	Rejected based on cost.		-£0.14	-£0.14	-£0.14	-£0.14	

Investment Business Case

CBA No.	19
Scheme/Project Name	Civic Centre
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Facilitate future demand
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	To replace existing site by establishing new double transformer primary substation adjacent to Electricity Street	Adopted
1	To establish double transformer primary substation in Cloughton Ave and interconnect to Electricity Street at 11kV.	Rejected

Background & Justification

Investment in the local electricity distribution system in Crewe, Cheshire to facilitate demand and economic growth of the Central Business District.

Civic Centre – Claughton Ave – Electricity Street 33/11kV Reinforcement

This is a three transformer HV group supporting the network on the western side of Crewe Town. The network is centred on Electricity Street with Civic Centre to the north and Claughton Avenue to the south.

The firm capacity of the group is 20MVA. Since 2009 new loads have been connected in this group raising the maximum demand from 16.7MVA in 2008/09 to19.9 in 2009/10 and 20.6MVA in 2010/11, this reduced to 18.1MVA in the milder winter of 2011/12. The load profile is a typical town centre profile with a winter day being flat with a small increase at 18:00hrs, this reducing to 50% of maximum during the night and peaking around 14MVA during the summer months.
The demand on each transformer is reasonably balanced and due to the number of 11kV circuits, transformer outages can be taken.

Forecast load growth and a winter at a ten year average temperature would result in demands above the firm rating of this group.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - replace existing site by establishing new double transformer primary substation adjacent to Electricity Street – **Option Chosen**

- establish a new double transformer primary substation including:
Offline build of new 33/11kV Substation including: 6-panel 33kV GIS board; 2x 33/11kV transformers; 12 panel 11kV board

- Would resolve thermal constraints on this group
- Dependant on aquisition of land adjacent to existing substation

Option 1 - establish double transformer primary substation in Cloughton Ave and interconnect to Electricity Street at 11kV.

- Convert existing Cloughton Ave substation into a double transformer primary substation including: 6-panel 33kV GIS board; 2x 33/11kV transformers; 12 panel 11kV board
- Outage of transformer at Electricity Street substation would overload interconnections at 11kV, additional interconnection required
This would:
- resolve thermal constraints on this group

Term (years from first out flow)	NPV (£m)
16	-£0.04
24	-£0.05
32	-£0.05
45	-£0.06
first year of investment out flow	3

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to replace existing site by establishing new double transformer primary substation adjacent to Electricity Street	- establish a new double transformer primary substation including: Offline build of new 33/11kV Substation including: 6-panel 33kV GIS board; 2x 33/11kV transformers; 12 panel 11kV board - Would resolve thermal constraints on this group - Dependant on aquisition of land adjacent to existing substation
Option 1 to establish double transformer primary substation in Cloughton Ave and interconnect to Electricity Street at 11kV.	- Convert existing Cloughton Ave substation into a double transformer primary substation including: 6-panel 33kV GIS board; 2x 33/11kV transformers; 12 panel 11kV board - Outage of transformer at Electricity Street substation would overload interconnections at 11kV, additional interconnection required This would: - resolve thermal constraints on this group
Do Nothing	Would significantly increase risk of supply security to customers in the central Crewe area and would breech Licence obligations under P2/6. This option has been rejected.
Dynamic Thermal Ratings of Transformers (Smart Solution)	This option is required in early ED1. It is also unlikely that this technology would release sufficient thermal headroom. Trials of real time thermal rating of transformers are ongoing. Should these trials present a release of capacity sufficient for this application, then this option would be revisited. At this stage, this option has been rejected due to technical risk.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	To replace existing site by establishing new double transformer primary substation adjacent to Electricity Street	Adopted	Enduring solution, though dependant on aquisition of land adjacent to Electricity Street substation						
1	To establish double transformer primary substation in Cloughton Ave and interconnect to Electricity Street at 11kV.	Rejected	Rejected based on cost.		-£0.04	-£0.05	-£0.05	-£0.06	

Investment Business Case

CBA No.	20
Scheme/Project Name	Beaumaris
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Facilitate demand gowth
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	to install a second transformer at Beaumaris, secure this second transformer using a new 33kV line from Llandegfan	Adopted
1	to establish a new single transformer 33/11kV substation in the Llandonna area.	Rejected

Background & Justification

Investment in the local electricity distribution system supplying Beaumaris, Anglesey to facilitate demand growth in the South Eastern area of Anglesey.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - nstall a second transformer at Beaumaris, secure this second transformer using a new 33kV line from Llandegfan – **Option Chosen**

Requires:
- second transformer at Beaumaris
- 7km 33kV circuit from Llandegfan
- 33kV switchgear: 5-panel board at Beaumaris, 3-panel board at Llandegfan

This will secure this area of Angelsey for 10MVA of demand.

Option 1 establish a new single transformer 33/11kV substation in the Llandonna area.

Requires:
- establish new primary substation
- 8km 33kV circuit from Pentreath
- 33kV switchgear: transformer feeder at Pentreath
- Reconfiguration of HV network

This will secure this area of Angelsey.

Term (years from first out flow)	NPV (£m)
16	-£0.19
24	-£0.23
32	-£0.26
45	-£0.28
first year of investment out flow	4

Option 2: Do nothing

Rejected - would not satisfy regulatory commitments under Condition 24 of Licence obligation requirements, would not satisfy commitments under planning standard Engineering Recommendation ER P2/6

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to install a second transformer at Beaumaris, secure this second transformer using a new 33kV line from Llandegfan	Requires: - second transformer at Beaumaris - 7km 33kV circuit from Llandegfan - 33kV switchgear: 5-panel board at Beaumaris, 3-panel board at Llandegfan This will secure this area of Angelsey for 10MVA of demand
Option 1 to establish a new single transformer 33/11kV substation in the Llandonna area.	Requires: - establish new primary substation - 8km 33kV circuit from Pentreath - 33kV switchgear: transformer feeder at Pentreath - Reconfiguration of HV network This will secure this area of Angelsey
Do Nothing	Rejected - would not satisfy regulatory commitments under Condition 24 of Licence obligation requirements, would not satisfy commitments under planning standard Engineering Recommendation ER P2/6

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	to install a second transformer at Beaumaris, secure this second transformer using a new 33kV line from Llandegfan	Adopted	Based on cost						
1	to establish a new single transformer 33/11kV substation in the Llandonna area.	Rejected	rejected based on cost		-£0.19	-£0.23	-£0.26	-£0.28	

Investment Business Case

CBA No.	21
Scheme/Project Name	Ringway
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Satisfy demand and faciliate future growth
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	To replace the existing Mobberley to Ringway circuit and install a new transformer	Adopted
I	To install additional 33 kV circuit from Ilford and new transformer at Ringway	Rejected

Background & Justification

Strategic investment in the electricity distribution system in Ringway area in order to satisfy the existing demand requirements and accommodate future load growth.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - replace the existing Mobberley to Ringway circuit and install a new transformer – **Option Chosen**

The baseline scenario is to replace the existing Mobberley to Ringway circuit (the existing to form part of the new Ringway to Knutsford circuit) with a new 33 kV circuit from the existing 33 kV way to Mobberley to a new 7.5 MVA transformer at Ringway. This will also require the changing of the existing South Wales C4X switchboard. The new 33 kV circuit will be 8 km and consists of a mixture of overhead and underground circuits. This extension will increase the firm capacity at Ringway to 10 MVA.

Option 1 - install additional 33 kV circuit from Ilford and new transformer at Ringway

Option 1 is to replace establish a new 33 kV circuit from Ilfords to a new 7.5 MVA transformer at Ringway. The new 33 kV circuit will be approximately 7.8 km and consists of a mixture of overhead and underground circuits.

Term (years from first out flow)	NPV (£m)
16	-£0.17
24	-£0.21
32	-£0.24
45	-£0.27
first year of investment out flow	3

Option 2: - Do nothing

Rejected - would not satisfy regulatory commitments under Condition 24 of Licence obligation requirements, would not satisfy commitments under planning standard Engineering Recommendation ER P2/6

Option 3 - Dynamic thermal ratings of existing 33/11kV transformers
(Smart Solution)

Dynamic thermal ratings would be expected to provide limited thermal headroom and the existing demand growth in this area is such that this solution would not be expected to manage the risk to the transformers for more than a few years. Therefore a conventional solution is more appropriate.

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to replace the existing Mobberley to Ringway circuit and install a new transformer	The baseline scenario is to replace the existing Mobberley to Ringway circuit (the existing to form part of the new Ringway to Knutsford circuit) with a new 33 kV circuit from the existing 33 kV way to Mobberley to a new 7.5 MVA transformer at Ringway. This will also require the changing of the existing South Wales C4X switchboard. The new 33 kV circuit will be 8 km and consists of a mixture of overhead and underground circuits. This extension will increase the firm capacity at Ringway to 10 MVA.
Option 1 is to install additional 33 kV circuit from Ilford and new transformer at Ringway	Option 1 is to replace establish a new 33 kV circuit from Ilfords to a new 7.5 MVA transformer at Ringway. The new 33 kV circuit will be approximately 7.8 km and consists of a mixture of overhead and underground circuits.
Do Nothing	Rejected - would not satisfy regulatory commitments under Condition 24 of Licence obligation requirements, would not satisfy commitments under planning standard Engineering Recommendation ER P2/6
Dynamic thermal ratings of existing 33/11kV transformers (Smart Solution)	Dynamic thermal ratings would be expected to provide limited thermal headroom and the existing demand growth in this area is such that this solution would not be expected to manage the risk to the transformers for more than a few years. Therefore a conventional solution is more appropriate.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	To replace the existing Mobberley to Ringway circuit and install a new transformer	Adopted	This option is able to resolve both thermal and voltage issues at slightly cheaper cost. Therefore this option is adopted.						
1	To install additional 33 kV circuit from Ilford and new transformer at Ringway	Rejected	This option is able to resolve both thermal and voltage issues, but the cost is slightly higher than baseline option due to slightly longer cable length. Therefore this option is rejected.		-£0.17	-£0.21	-£0.24	-£0.27	

Investment Business Case

CBA No.	22
Scheme/Project Name	Cheshire Oaks
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Faciliate future demand growth
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	to establish new single transformer primary substation at Cheshire Oaks, provide 33kV supply from Ellesmere Port. Group at 11kV with Chester Gates/Unilever	Adopted
1	to establish new single transformer primary substation in NE area of Cheshire Oaks, provide 33kV supply by loop-in on Cabot-Carbon - BPA. Split Robertsons/Bowaters/Ellesmere Port group with additional transformer at Robertsons.	Rejected

Background & Justification

Investment in the electricity distribution system in near Cheshire Oaks, Cheshire to facilitate demand growth in the area.

Cheshire Oaks 33/11kV Reinforcement

Cheshire Oaks is a large, established Outlet Village and retail complex, the area is still attracting new customers which are increasing the demand in the area. The area is supported by a five transformer group but there are no primaries in the Cheshire Oaks area. The 6MVA of demand being supported by two 11kV circuits, the area being on the southern edge the Ellesmere Port network and isolated to the east by the M53 which prevents interconnection with the network to the east of the M53. Recent new connections have required 11kV cable lays and network reconfigurations with the introduction of a new transformer to the north of the group and the removal of Chester Gates primary from the group which now operates as a two transformer group with Unilever.

This concentration of demand also unbalances the five transformer group resulting in the full capacity of the group not being available to support the Cheshire Oaks network.
The existing group is fully secure but it is increasingly difficult to support new connections which are not of sufficient capacity to justify a new primary as part of the individual offer.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

<u>**Business as Usual Option (Baseline) -** establish new single transformer primary substation at Cheshire Oaks, provide 33kV supply from Ellesmere Port. Run as standalone. – **Option Chosen**</u>

Requires
- establish a new single transformer primary substation including:
  3-panel 33kV GIS board; 1x 33/11kV transformers; 7 panel 11kV board
- provide 33kV supply from Ellesmere Port

This will:
- provide significant additional capacity for demand / generation growth in Cheshire Oaks area

<u>Option 1 - establish new single transformer primary substation in NE area of Cheshire Oaks, provide 33kV supply by loop-in on Cabot-Carbon - BPA. Split Robertsons/Bowaters/Ellesmere Port group with additional transformer at Robertsons.</u>

Requires
- establish a new single transformer primary substation including:
  3-panel 33kV GIS board; 1x 33/11kV transformers; 8 panel 11kV board
- provide 33kV supply from Ellesmere Port
- regroup at 11kV by splitting Robertsons/Bowaters/Ellesmere Port group with an additional transformer at Robertsons.

This will:
- provide significant additional capacity for demand / generation growth in Cheshire Oaks area

Term (years from first out flow)	NPV (£m)
16	-£0.55
24	-£0.66
32	-£0.74
45	-£0.81
first year of investment out flow	2

Option 2 - Do nothing

Rejected - would not satisfy regulatory commitments under Condition 24 of Licence obligation requirements, would not satisfy commitments under planning standard Engineering Recommendation ER P2/6

Option 3 - Dynamic thermal ratings of existing 33/11kV transformers (Smart Solution)

Dynamic thermal ratings would be expected to provide limited thermal headroom and the existing demand growth in this area is such that this solution would not be expected to manage the risk to the transformers for more than a few years. Therefore a conventional solution is more appropriate.

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to establish new single transformer primary substation at Cheshire Oaks, provide 33kV supply from Ellesmere Port. Run as standalone.	Requires - establish a new single transformer primary substation including: 3-panel 33kV GIS board; 1x 33/11kV transformers; 7 panel 11kV board - provide 33kV supply from Ellesmere Port This will: - provide significant additional capacity for demand / generation growth in Cheshire Oaks area
Option 1 to establish new single transformer primary substation in NE area of Cheshire Oaks, provide 33kV supply by loop-in on Cabot-Carbon BPA. Split Robertsons/Bowaters/Ellesmere Port group with additional transformer at Robertsons.	Requires - establish a new single transformer primary substation including: 3-panel 33kV GIS board; 1x 33/11kV transformers; 8 panel 11kV board - provide 33kV supply from Ellesmere Port - regroup at 11kV by splitting Robertsons/Bowaters/Ellesmere Port group with an additional transformer at Robertsons. This will: - provide significant additional capacity for demand / generation growth in Cheshire Oaks area
Do Nothing	Rejected - would not satisfy regulatory commitments under Condition 24 of Licence obligation requirements, would not satisfy commitments under planning standard Engineering Recommendation ER P2/6
Dynamic thermal ratings of existing 33/11kV transformers (Smart Solution)	Dynamic thermal ratings would be expected to provide limited thermal headroom and the existing demand growth in this area is such that this solution would not be expected to manage the risk to the transformers for more than a few years. Therefore a conventional solution is more appropriate.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	to establish new single transformer primary substation at Cheshire Oaks, provide 33kV supply from Ellesmere Port. Group at 11kV with Chester Gates/Unilever	Adopted	Based on cost						
1	to establish new single transformer primary substation in NE area of Cheshire Oaks, provide 33kV supply by loop-in on Cabot-Carbon - BPA. Split Robertsons/Bowaters/Ellesmere Port group with additional transformer at Robertsons.	Rejected	Based on cost		-£0.55	-£0.66	-£0.74	-£0.81	

Investment Business Case

CBA No.	23
Scheme/Project Name	Runcorn
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Facilitate future demand growth
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	To establish a new 7.5 MVA primary transformer in shopping city subs	Adopted
I	To establish a new primary substation near Palace Fields	Rejected

Background & Justification

Strategic investment in the electricity distribution system in Runcorn area in order to satisfy the existing demand requirements and accommodate future load growth.

The four transformer group supporting the mixed of Runcorn town has a firm capacity of 30 MVA. Three of the transformers have good interconnection between each other. Murdishaw also has good interconnection but mainly to Runcorn Central primary. For the last five years this group has recorded a maximum demand of 25 MVA to 27 MVA except during the mild winter of 2011/12. The demand profile shows an early evening peak, with a day load below 20 MVA and a summer peak of 17 MVA. Due to the conection arrangement in the group if the Murdishaw transformer is off at peak demands the Runcorn Central transformer is at its maximum short term rating. All other outages within the group can be taken within the ratings of the network. Future forecast load growth through ED1 and an average winterwould mean an outage of Murdishaw would result in Runcorn Central exceeding its maximum thermal rating, even though the group load would be around 90% of its theoretical firm capacity.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - establish a new 7.5 MVA primary transformer in Shopping City Sub – **Option Chosen**

There are a number of primary sites in Runcorn. The baseline scenario is to equip the site Shopping City with a 7.5 MVA primary transformer, a three panel 33 kV and eight panel 11 kV boards. The 33 kV circuit is within 500m and two 11 kV circuits also pass the site. To ensure an even sharing of network demand, additional reinforcement work will be required alter the network around Runcorn Central substation. This option as well as evenly distributing the demand will increase the group firm capacity to 40 MVA, a 35% increase on present demand.

Option 1 establish a new primary substation near Palace Fields

This option considers establishing a new 33/11kV, single primary transformer substation on the edge of the 'Palace fields' playing fields. This would be looped into the Dutton Grid – Murdishaw 33kv feeder. Three 11kV feeders would be turned into this substation. The substation would require a 7.5MVA transformer, a three panel 33 kV and eight panel 11 kV board. The 33kV circuit is within 350m and one of the 11kV feeders passes the site.
To ensure an even sharing of network demand, additional reinforcement work will be required alter the network around Runcorn Central substation. This option as well as evenly distributing the demand will increase the group firm capacity to 40 MVA, a 35% increase on present demand.

Term (years from first out flow)	NPV (£m)
16	-£0.07
24	-£0.09
32	-£0.10
45	-£0.11
first year of investment out flow	4

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to establish a new 7.5 MVA primary transformer in Shopping City Sub	There are a number of primary sites in Runcorn. The baseline scenario is to equip the site Shopping City with a 7.5 MVA primary transformer, a three panel 33 kV and eight panel 11 kV boards. The 33 kV circuit is within 500m and two 11 kV circuits also pass the site. To ensure an even sharing of network demand, additional reinforcement work will be required alter the network around Runcorn Central substation. This option as well as evenly distributing the demand will increase the group firm capacity to 40 MVA, a 35% increase on present demand.
Option 1 to establish a new primary substation near Palace Fields	This option considers establishing a new 33/11kV, single primary transformer substation on the edge of the 'Palace fields' playing fields. This would be looped into the Dutton Grid – Murdishaw 33kv feeder. Three 11kV feeders would be turned into this substation. The substation would require a 7.5MVA transformer, a three panel 33 kV and eight panel 11 kV board. The 33kV circuit is within 350m and one of the 11kV feeders passes the site. To ensure an even sharing of network demand, additional reinforcement work will be required alter the network around Runcorn Central substation. This option as well as evenly distributing the demand will increase the group firm capacity to 40 MVA, a 35% increase on present demand.
Establish a second primary transformer in Runcorn Central	This option can resolve the issue as well will increase the group firm capacity to 40 MVA, a 35% increase of present demand at cheaper cost. However, it is not feasible as there is no extra room for a second primary transformer.
Establish a second primary transformer in Murdishaw	This option can secure the lost of existing Murdishaw transformer as well will increase the group firm capacity to 40 MVA, a 35% increase of present demand at cheaper cost. However, it is not feasible as there is no extra room for a second primary transformer.
Establish a second primary transformer in Halton Road	This option can secure the lost of existing Halton Road transformer as well will increase the group firm capacity to 40 MVA, a 35% increase of present demand at cheaper cost. However, it is not feasible as there is no extra room for a second primary transformer.
Install a single primary transformer in Runcorn Hospital	This option can secure the lost of existing Halton Road transformer as well will increase the group firm capacity to 40 MVA, a 35% increase of present demand at cheaper cost. However, it is not feasible as there is no extra room for a second primary transformer.
Do Nothing	Rejected - would not satisfy regulatory commitments under Condition 24 of Licence obligation requirements, would not satisfy commitments under planning standard Engineering Recommendation ER P2/6
Dynamic thermal ratings of existing 33/11kV transformers (Smart Solution)	Dynamic thermal ratings would be expected to provide limited thermal headroom and the existing demand growth in this area is such that this solution would not be expected to manage the risk to the transformers for more than a few years. Therefore a conventional solution is more appropriate.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	To establish a new 7.5 MVA primary transformer in shopping city subs	Adopted	This is the cheapest feasible solution to resolve the issues and is considered to be an enduring solution.						
1	To establish a new primary substation near Palace Fields	Rejected	Rejected based on cost		-£0.07	-£0.09	-£0.10	-£0.11	

Investment Business Case

CBA No.	24
Scheme/Project Name	Coedpoeth
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Satisfy current demand and accomodate future growth
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	To replace Coedpoeth transformer	Rejected
1	to install Real Time Thermal Ratings (smart)	Adopted

Background & Justification

Strategic investment in the electricity distribution system in the Wrexham area in order to satisfy the existing demand requirements and accommodate future load growth.

Coedpoeth is a rural style substation to the west of Wrexham and supports the villages of Coedpoeth, Minera, Brmybo and the rural network to Llandegla. Brymbo has a large brown field site (an old steel works site) which in recent years has seen new housing being established. Further areas of land have been allocated for future development. The small Minera industrial estate has also seen a small demand increase.
For the last five years Coedpoeth has seen a steadily rising demand. The five year demands have risen from 6.9MVA to 7.1MVA in 2010/11. The point load of Coedpoeth village and Brymbo makes supporting this network under outage conditions difficult and involves a large amount of switching. It is expected that with future forecast load growth marginal overloading of this transformer could be experienced.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - replace Coedpoeth transformer

Upgrade the existing transformer at Coedpoeth with a 7.5/10MVA unit.

Option 1 - install Real Time Thermal Ratings – **Option Chosen**

Use real-time measurements of transformer temperature, current flow and ambient temperature to assess the risk to the expected assest life and better assess the demand behaviour. This will free a limited amount of demand capacity as the transformer can be operated to supply higher levels of demand than would normally be allowed.

Term (years from first out flow)	NPV (£m)
16	£0.03
24	£0.02
32	£0.01
45	£0.00
first year of investment out flow	3

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to replace Coedpoeth transformer	Upgrade the existing transformer at Coedpoeth with a 7.5/10MVA unit.
Option 1 to install Real Time Thermal Ratings (Smart Solution)	Use real-time measurements of transformer temperature, current flow and ambient temperature to assess the risk to the expected assest life and better assess the demand behaviour. This will free a limited amount of demand capacity as the transformer can be operated to supply higher levels of demand than would normally be allowed.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	To replace Coedpoeth transformer	Rejected	Based on cost						
1	to install Real Time Thermal Ratings (smart)	Adopted	Based on cost. This is considered to be a Smart Solution.		£0.03	£0.02	£0.01	£0.00	

Investment Business Case

CBA No.	25
Scheme/Project Name	Graig Fawr
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Satisfy current demand and accomodate future growth
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	To replace Graig Fawr transformer	Rejected
I	to install Real Time Thermal Ratings	Adopted

Background & Justification

Strategic investment in the electricity distribution system in the Prestatyn area in order to satisfy the existing demand requirements and accommodate future load growth.

Graig Fawr is an outdoor 33kV compound substation supporting the outskirts of Prestatyn and the rural network to the south. The 33kV is a two breaker compound with a 7.5MVA transformer feeding onto a single bus section SW C4X 11kV board, the substation being operated as a single group.
The firm capacity of Graig Fawr is 7.5MVA and during the last five years has recorded a maximum demand of 7MVA for three of the five years.
Forecast future demand growth, based on the average maximum demand over the last few years would result in marginal overloading of this substation being experienced.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - replace Graig Fawr transformer

Upgrade the existing transformer at Graig Fawr with a 7.5/10MVA unit.

Option 1 - install Real Time Thermal Ratings (Smart Solution) – **Option Chosen**

Use real-time measurements of transformer temperature, current flow and ambient temperature to assess the risk to the expected assest life and better assess the demand behaviour. This will free a limited amount of demand capacity as the transformer can be operated to supply higher levels of demand than would normally be allowed.

Term (years from first out flow)	NPV (£m)
16	£0.02
24	£0.01
32	-£0.00
45	-£0.01
first year of investment out flow	7

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to replace Graig Fawr transformer	Upgrade the existing transformer at Graig Fawr with a 7.5/10MVA unit.
Option 1 to install Real Time Thermal Ratings (Smart Solution)	Use real-time measurements of transformer temperature, current flow and ambient temperature to assess the risk to the expected assest life and better assess the demand behaviour. This will free a limited amount of demand capacity as the transformer can be operated to supply higher levels of demand than would normally be allowed.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	To replace Graig Fawr transformer	Rejected	Based on cost						
1	to install Real Time Thermal Ratings	Adopted	Based on cost. This is considered to be a Smart Solution.		£0.02	£0.01	-£0.00	-£0.01	

Investment Business Case

CBA No.	26
Scheme/Project Name	Tarvin
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Satisfy existing demand and accomodate future growth
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	To install a second transformer at Tarvin	Rejected
1	to install Real Time Thermal Ratings	Adopted

Background & Justification

Strategic investment in the electricity distribution system in the Tarvin area in order to satisfy the existing demand requirements and accommodate future load growth.

Tarvin is a two breaker 33kV substation supporting the village of Tarvin and other rural villages to the east of Chester. The two outdoor EE OKM4 33kV circuit breakers feed a Brush 7.5MVA transformer and a single busbar six panel GEC VMX 11kV board.
In the last five years the highest transformer MD was 7.3MVA in 2010/11, the lowest being 6.7MVA in 2006/07.
Although in the last five years the transformer has not exceeded its firm capacity of 7.5MVA, allowing for future demand growth in the area it is expected that the substation will be marginally over it firm capacity by the end of the period.
The 11kV network from the adjacent substations can support the point loads of Tarvin and Kelsall villages and the surrounding network.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - install a second transformer at Tarvin

Install a second transformer at Tarvin which would share the demand and facilitate future load growth and enable future outages to be taken with minimal load transfer.

Option 1 - install Real Time Thermal Ratings – **Option Chosen**

Use real-time measurements of transformer temperature, current flow and ambient temperature to assess the risk to the expected assest life and better assess the demand behaviour. This will free a limited amount of demand capacity as the transformer can be operated to supply higher levels of demand than would normally be allowed.

Term (years from first out flow)	NPV (£m)
16	£0.14
24	£0.13
32	£0.11
45	£0.10
first year of investment out flow	5

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to install a second transformer at Tarvin	Install a second transformer at Tarvin which would share the demand and facilitate future load growth and enable future outages to be taken with minimal load transfer.
Option 1 to install Real Time Thermal Ratings (Smart Solution)	Use real-time measurements of transformer temperature, current flow and ambient temperature to assess the risk to the expected assest life and better assess the demand behaviour. This will free a limited amount of demand capacity as the transformer can be operated to supply higher levels of demand than would normally be allowed.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	To install a second transformer at Tarvin	Rejected	Based on cost						
1	to install Real Time Thermal Ratings	Adopted	Based on cost. This is considered to be a Smart Solution.		£0.14	£0.13	£0.11	£0.10	

Investment Business Case

CBA No.	27
Scheme/Project Name	Aintree 33kV
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Resolve fault level constraints
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	To replace the existing 33kV switchboards at Aintree and Litherland	Adopted
I	To split the 33kV group into two at Almonds Turn	Rejected

Background & Justification

Strategic investment in the electricity distribution system in the Aintree and Litherland areas of Merseyside to resolve fault level constraints.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - replace the existing switchboards at both Aintree and Litherland substations – **Option Chosen**

It is proposed to replace the existing 12 panel Aintree grid 33 kV switchboard and the associated remote end protection modifications at the earliest opportunity in the ED1 price review period. Also to replace the existing 11 panel Litherland 33kV switchboard as associated remote end protection modifications later in the ED1 price review period.
It is assumed that the protection replacement costs are included in schemes and new buildings for offline build of new switchboards. In situ replacement considered not possible due to operational difficulties and risks to maintain security of supplies in both sites.

Option 1 - split the 33kV group into two at Almonds Turn

This possible solution is to split the existing group into two groups of two grid transformers by establishing a grid transformer site at Almonds Turn and turn-in the 33kV feeders. This mitigates the fault level issues within this group at Aintree and Litherland. However, both Aintree and Litherland substations are run with split boards and the opposite side of both boards still have high fault levels which would need to be managed operationally.

Term (years from first out flow)	NPV (£m)
16	-£4.92
24	-£5.91
32	-£6.59
45	-£7.26
first year of investment out flow	3

Option 2: Do nothing

Rejected - would not satisfy regulatory commitments under Condition 24 of Licence obligation requirements.

Option 3 - Fault Current Limiters

The development and effectiveness of fault current limiters used in WPD networks will be closely monitored and this technology will be considered as it develops.

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to replace the existing switchboards at both Aintree and Litherland substations	It is proposed to replace the existing 12 panel Aintree grid 33 kV switchboard and the associated remote end protection modifications at the earliest opportunity in the ED1 price review period. Also to replace the existing 11 panel Litherland 33kV switchboard as associated remote end protection modifications later in the ED1 price review period. It is assumed that the protection replacement costs are included in schemes and new buildings for offline build of new switchboards. In situ replacement considered not possible due to operational difficulties and risks to maintain security of supplies in both sites.
Option 1 is to split the 33kV group into two at Almonds Turn	This possible solution is to split the existing group into two groups of two grid transformers by establishing a grid transformer site at Almonds Turn and turn-in the 33kV feeders. This mitigates the fault level issues within this group at Aintree and Litherland. However, both Aintree and Litherland substations are run with split boards and the opposite side of both boards still have high fault levels which would need to be managed operationally.
Do Nothing	Rejected - would not satisfy regulatory commitments under Condition 24 of Licence obligation requirements.
Fault Current Limiters	The development and effectiveness of fault current limiters used in WPD networks will be closely monitored and this technology will be considered as it develops.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	To replace the existing 33kV switchboards at Aintree and Litherland	Adopted	Adopted based on cost						
1	To split the 33kV group into two at Almonds Turn	Rejected	Rejected based on cost		-£4.92	-£5.91	-£6.59	-£7.26	

Investment Business Case

CBA No.	28
Scheme/Project Name	Chester Fault Level Mitigation
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Strategic investment in the electricity distribution system in the Chester area in order to resolve fault level constraints and accommodate future load growth.
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
1	Baseline	Rejected
2	Option 2 - Establish auto-close scheme at Saltney and replace 2 RMUs. Smart Solution.	Adopted

Background & Justification

The existing transformer at Saltney Grid can be selected to either the Chester 33kV group (Chester, Guilden Sutton, Crane Bank) or the adjacent substation group and a second transformer is currently being installed that will operate on open standby due to fault level constraints. One of the transformers at Saltney Grid is required to operate permanently in service or to be immediately available following a n-1 outage in order to operationally manage the demand growth forecast during the ED1 period. There are also two 33kV RMUs in which fault level is exceeded based on the current system configuration.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

<u>Business as Usual Option 1 (Baseline)</u>

The baseline option is to change a number of 33kV RMUs and install fault level monitors on the remaining RMU that are operating close to fault level limits with Saltney Grid transformer normally in service.

<u>Option 2 - Establish auto-close scheme at Saltney and replace 2 RMUs. Smart Solution – **Chosen Option**</u>

Option 2 is a smart solution to replace two RMUs in order to resolve existing fault level issues and to install system automation that will automatically close Saltney Grid transformer for an n-1 outage in the wider group. It is also proposed to install fault level monitoring at switchgear operating close to fault level limits.

Term (years from first out flow)	NPV (£m)
16	£1.41
24	£1.74
32	£1.97
45	£2.20
first year of investment out flow	3

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Option 1 - Baseline	The baseline option is to change a number of 33kV RMUs and install fault level monitors on the remaining RMU that are operating close to fault level limits with Saltney Grid transformer normally in service.
Option 2 - Establish system automation and replace 2 RMUs	Option 2 is a smart solution to replace two RMUs in order to resolve existing fault level issues and to install system automation that will automatically close Saltney Grid transformer for an n-1 outage in the wider group. It is also proposed to install fault level monitoring at switchgear operating close to fault level limits.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	Baseline	Rejected			£0.00	£0.00	£0.00	£0.00	
2	Option 2 - Establish auto-close scheme at Saltney and replace 2 RMUs. Smart Solution.	Adopted	As there are no engineering reasons for not utilising this technology the highest NPV has been chosen.		£1.41	£1.74	£1.97	£2.20	

Investment Business Case

CBA No.	29
Scheme/Project Name	Warrington
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Resolve fault level constraints, increase supply security of the local area and facilitate load growth in the local area.
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	To split Warrington North and South into two distinct 33kV demand groups	Rejected
1	To replace all RMU's / switchboards affected by the high fault levels	Rejected
2	To split the groups and cross-couple by installing reactors in Sankey Bridges, Dallem, and Warrington substations.	Adopted

Background & Justification

Investment in the electricity distribution system in Warrington, Cheshire to resolve fault level constraints, increase supply security of the local area and facilitate load growth in the local area.

The SPM 33kV interconnected network in the Warrington region of Cheshire is an area where short circuit fault current levels (both 'make' and 'break') are in excess of plant ratings.

Due to these fault level constraints it is also necessary to operate one grid transformer at Sankey Bridges on open standby. Fault levels can only be reduced by splitting the 33kV system which in turn impacts upon the security of supply provided to the whole group.

An assessment has been undertaken to identify solutions that will mitigate the fault level constraints and at the same time resolve the supply security risks, provide an enduring minimum scheme solution.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

<u>**Business as Usual Option (Baseline) -** split Warrington North and South into two distinct 33kV demand groups</u>

Requires :

- a new 132/33kV grid transformer at Thelwall grid suppiled by tee from the Warrington-Carrington 132kV circuit
- 33kv cable reconfigurations within the Warrington and Sankey Bridges substations

This will:

- provide significant additional capacity for demand / generation growth in both North and South Warrington
- remove the security of supply risk due to common model of failure of four 33kV circuits
- Does not resolve all 33kV fault level issues in the Warrington area

<u>Option 1 - replace all RMU's / switchboards affected by the high fault levels</u>

Requires

- RMU / switchboard replacement at 10 locations

This will:

- mitigate the fault level issues in the group
- difficulties in securing outages at grid sites, introduces significant risk to customer supplies during construction periods
- will not resolve the common mode of failure of the four 33kV circuits

Term (years from first out flow)	NPV (£m)
16	£0.59
24	£0.71
32	£0.79
45	£0.88
first year of investment out flow	1

<u>Option 2: - Split the groups and cross-couple by installing reactors in Sankey Bridges, Dallem, and Warrington substation – **Chosen Option**</u>

Requires - Split the groups and cross couple by installing new reactors at Sankey Bridges, Dallem and Warrington substations - Split the Warrington Central feeder between the Dallem-Sankey Bridges and Dallem-Warrington Grid groups This will: - mitigate the fault level issues in the group - the common mode of failure of the four 33kV circuits no longer as onerous <u>Option 3 – Do nothing</u> Rejected - would not satisfy regulatory commitments under Condition 4 of Licence obligation requirements. <u>Option 4 - Fault Current Limiters (Smart Solution)</u> The development and effectiveness of fault current limiters used in WPD networks project will be closely monitored and this technology will be considered as it develops.

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to split Warrington North and South into two distinct 33kV demand groups	Requires - a new 132/33kV grid transformer at Thelwall grid suppiled by tee from the Warrington-Carrington 132kV circuit - 33kv cable reconfigurations within the Warrington and Sankey Bridges substations This will: - provide significant additional capacity for demand / generation growth in both North and South Warrington - remove the security of supply risk due to common model of failure of four 33kV circuits - Does not resolve all 33kV fault level issues in the Warrington area
Option 1 to replace all RMU's / switchboards affected by the high fault levels	Requires - RMU / switchboard replacement at 10 locations This will: - mitigate the fault level issues in the group - difficulties in securing outages at grid sites, introduces significant risk to customer supplies during construction periods - will not resolve the common mode of failure of the four 33kV circuits
Option 2 to split the groups and cross-couple by installing reactors in Sankey Bridges, Dallem, and Warrington substations.	Requires - Split the groups and cross couple by installing new reactors at Sankey Bridges, Dallem and Warrington substations - Split the Warrington Central feeder between the Dallem-Sankey Bridges and Dallem-Warrington Grid groups This will: - mitigate the fault level issues in the group - the common mode of failure of the four 33kV circuits no longer as onerous
Do Nothing	Rejected - would not satisfy regulatory commitments under Condition 4 of Licence obligation requirements.
Fault Current Limiters (Smart Solution)	The development and effectiveness of fault current limiters used in WPD networks project will be closely monitored and this technology will be considered as it develops.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	To split Warrington North and South into two distinct 33kV demand groups	Rejected	Rejected as does not resolve all fault level issues in the group.						
1	To replace all RMU's / switchboards affected by the high fault levels	Rejected	- mitigates the fault level issues in the group - difficulties in securing outages at grid sites, introduces significant risk to customer supplies during construction periods - will not resolve the common mode of failure of the four 33kV circuits		£0.59	£0.71	£0.79	£0.88	
2	To split the groups and cross-couple by installing reactors in Sankey Bridges, Dallem, and Warrington substations.	Adopted	- mitigates the fault level issues in the group - reduces impact of the common mode of failure of the four 33kV circuits - Adopted on Cost		£0.63	£0.63	£0.63	£0.63	

Investment Business Case

CBA No.	30
Scheme/Project Name	Gateacre Huyton
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Resolve fault level constraints
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	To replace the existing switchgear at Huyton and Gateacre	Adopted
I	To split the group to form two, two transformer groups	Rejected

Background & Justification

Strategic investment in the electricity distribution system in Gateacre Huyton area in order to resolve fault level constraints.

As part of the ongoing network analysis it has been identified that the Gateacre Huyton 33 kV group has fault level in excess of the switchgear rating. At Huyton and Gateacre the break fault level is above the rating of the installed 33 kV switchgear. An interim arrangement has been put in place to enable access to the affected sites and the sites recorded in line with the policy. To enable site access the group fault level is reduced by switching out Kirkby transformer and switching in the Prescot transformer which is normally operated with its LV breaker open. This is not an acceptable operating arrangement as under N-1 the resulting circuit flows are above cable ratings. This arrangement also creates 132 kV operating difficulties.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - replace the existing switchgear at Huyton and Gateacre – **Option Chosen**

It is proposed to replace the 33 kV boards at Gateacre and Huyton which will increase the fault break rating of the boards and enable the declared fault rating at the two sites to be increased from 750 MVA to 1000 MVA. The indicative cost of this option is £4M.

Option 1 - splitting the group to form two, two transformer groups

This proposal is to split the existing group into two groups of two transformers coupled by a bussection reactor at Huyton. This will require extending the existing 33 kV boards at Huyton and Gateacre by one circuit breaker as well as the installation of a reactor at Huyton. To rearrange the 33 kV network to enable this regrouping will also require the installation of a 4.8 km single cable lay from Gateacre to Broadgreen. To enable the existing 11 kV grouping to be maintained will also require a 650m double cable lay to transfer Bedburn Drive to the other group as well as a 50m cable lay to transfer Prescot Rye Hay. Rearrangement of the 33 kV circuits at Huyton is also required to complete the network separation. The indicative cost of this proposal is £3.5M

Term (years from first out flow)	NPV (£m)
16	-£0.44
24	-£1.25
32	-£1.70
45	-£2.19
first year of investment out flow	1

Option 2: - Do nothing

Rejected - would not satisfy regulatory commitments under Condition 24 of Licence obligation requirements.

Option 3 - (Smart Solution)

The development and effectiveness of fault current limiters used in WPD networks will be closely monitored and this technology will be considered as it develops.

Appendix 1: Cost Benefit Analysis

Options considered	**Comment**
Baseline scenario to replace the existing switchgear at Huyton and Gateacre	It is proposed to replace the 33 kV boards at Gateacre and Huyton which will increase the fault break rating of the boards and enable the declared fault rating at the two sites to be increased from 750 MVA to 1000 MVA. The indicative cost of this option is £4M.
Option 1 is splitting the group to form two, two transformer groups	This proposal is to split the existing group into two groups of two transformers coupled by a bussection reactor at Huyton. This will require extending the existing 33 kV boards at Huyton and Gateacre by one circuit breaker as well as the installation of a reactor at Huyton. To rearrange the 33 kV network to enable this regrouping will also require the installation of a 4.8 km single cable lay from Gateacre to Broadgreen. To enable the existing 11 kV grouping to be maintained will also require a 650m double cable lay to transfer Bedburn Drive to the other group as well as a 50m cable lay to transfer Prescot Rye Hay. Rearrangement of the 33 kV circuits at Huyton is also required to complete the network separation. The indicative cost of this proposal is £3.5M
Do Nothing	Rejected - would not satisfy regulatory commitments under Condition 24 of Licence obligation requirements.
Fault Current Limiters (Smart Solution)	The development and effectiveness of fault current limiters used in WPD networks will be closely monitored and this technology will be considered as it develops.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	To replace the existing switchgear at Huyton and Gateacre	Adopted	This option is adopted even this is a slightly more expensive option because it leave sufficient room for the future extension of the boards to enable future splitting of the group if network demands require Prescot T1 to be permanently switched into service						
1	To split the group to form two, two transformer groups	Rejected	This option has been rejected as baseline spreads expenditure over ED1 and therefore is more economical over the first 16yr period. Also the fault level of Huyton is at 98% of the switchgear rating and it leave little room for future growth. It is not considered to be enduring solution.		-£0.44	-£1.25	-£1.70	-£2.19	

Investment Business Case

CBA No.	31
Scheme/Project Name	SPD EHV-HV Yoker Ferry Road
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Facilitate demand growth
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	establish a second 33/11kV substation at Yoker Ferry Road, supply from Braehead Park GSP	Adopted
1	establish a second 33/11kV substation at Yoker Ferry Road, supply from Drumchapel GSP	Rejected

Background & Justification

Investment in the electricity distribution system in Yorker Ferry Road area to facilitate demand growth.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - establish a second 33/11kV substation at Yoker Ferry Road, supply from Braehead Park GSP – **Chosen Option**

In order to resolve the substation loading issue, it is proposed to establish a Yorker Ferry "B" substation with a second pair of 12/24 MVA transformers and a new 15 panel 11 kV switchboard (two incomers, one bus section and 12 feeders distributed evenly over two sections). Given the proximity of the Braehead Park GSP and distance/problematic cable route to Drumchapel GSP, it is proposed that the new primary would be supplied from Braehead GSP via 33 kV river crossings. Considering the electrical isolation of Braehead GSO, it is further proposed to consider during the project development phase, the establishment of 33 kV switchgear at Yoker Ferry to facilitate the interconnection of the Drumchapel and Braehead Park 33 kV circuits.
This is enduring solution to resolve loading issues in Yorker Road area.

Option 1 - establish a second 33/11kV substation at Yoker Ferry Road, supply from Drumchapel GSP

In order to resolve the substation loading issue, it is proposed to establish a Yorker Ferry "B" substation with a second pair of 12/14 MVA transformers and a new 15 panel 11 kV switchboard (two incomers, one bus section and 12 feeders distributed evenly over two sections). The new substation will be supplied from Drumchapel GSP.

Term (years from first out flow)	NPV (£m)
16	-£0.56
24	-£0.70
32	-£0.79
45	-£0.89
first year of investment out flow	1

Option 2: - Do nothing

Would significantly increase risk of quality of supply issues to customers in the Yorker Road area and may eventually would lead to a breach of requirements of EREC P2/6. This option has been rejected.

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to establish a second 33/11kV substation at Yoker Ferry Road, supply from Braehead Park GSP	In order to resolve the substation loading issue, it is proposed to establish a Yorker Ferry "B" substation with a second pair of 12/24 MVA transformers and a new 15 panel 11 kV swittchboard (two incomers, one bus section and 12 feeders distributed evenly over two sections). Given the proximity of the Braehead Park GSP and distance/problematic cable route to Drumchapel GSP, it is proposed that the new primary would be supplied from Braehead GSP via 33 kV river crossings. Considering the electrical isolation of Braehead GSO, it is further proposed to consider during the project development phase, the establishment of 33 kV switchgear at Yoker Ferry to facilitate the interconnection of the Drumchapel and Braehead Park 33 kV circuits. This is enduring solution to resolve loading issues in Yorker Road area.
Option 1 to establish a second 33/11kV substation at Yoker Ferry Road, supply from Drumchapel GSP	In order to resolve the substation loading issue, it is proposed to establish a Yorker Ferry "B" substation with a second pair of 12/14 MVA transformers and a new 15 panel 11 kV switchboard (two incomers, one bus section and 12 feeders distributed evenly over two sections). The new substation will be supplied from Drumchapel GSP.
Do Nothing	Would significantly increase risk of quality of supply issues to customers in the Yorker Road area and may eventually would lead to a breach of requirements of EREC P2/6. This option has been rejected.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	establish a second 33/11kV substation at Yoker Ferry Road, supply from Braehead Park GSP	Adopted							
1	establish a second 33/11kV substation at Yoker Ferry Road, supply from Drumchapel GSP	Rejected	based on cost		-£0.56	-£0.70	-£0.79	-£0.89	

Investment Business Case

CBA No.	32
Scheme/Project Name	Spd ehv-hv Berwick (North Road – Loaning)
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Facilitate growth
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	establish a new primary substation	Adopted
1	to replace existing old transofrmers with higher rating new transformers (2 x 12/14 MVA) at North Road and The Loaning and establish new 33 kV OHL circuits to North Road	Rejected

Background & Justification

Investment in the electricity distribution system in Berwick Upon Tweed area to facilitate demand growth.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - establish a new primary substation – **Chosen Option**

To mitigate the overload on both primaries, it is considered that this is best achieved by establishing a new primary substation in the vicinity of East Ord Industrial Estate on the outskirts of Berwick and integrating that with the existing 11 kV network to transfer standing demand from the existing site.

As both sites are supplied by banked 33 kV circuits, the complexity of the 33 kV circuits cannot be extended to connect the new primary. Therefore, it is considered that the new primary will be connected by two new 33 kV circuits from Berwick GSP to the site. once integration is complete, the security of the system is improved as any one fault will leave a minimum of 4 transformers on load.

Option 1 - Replace existing old transformers with higher rating new transformers (2 x 12/24 MVA) at North Road and The Loaning, and establish new 33 kV circuits to North Road

The existing 2 x 10 MVA old transformers at North Road and The Loading will each be replaced with new 2 x 12/24 MVA transformers. This will increase the firm capacity to 24 MVA.

New 33 kV circuits are established from Berwick Grid to North Road primary. An overhead line fault will then leave a minimum of 3 transformers on load.

Term (years from first out flow)	NPV (£m)
16	-£0.29
24	-£0.35
32	-£0.40
45	-£0.44
first year of investment out flow	2

Option 2: - Do nothing

Would significantly increase risk of quality of supply issues to customers in the Berwick area and may eventually would lead to a breach of requirements of EREC P2/6. This option has been rejected.

Option 3 - Establish new 33 kV OHL circuits from Berwick Grid to North Road primary

An overhead line fault will leave at least 3 primary transformers on load which provide the opportunity to make load transfers at the 11 kV side. However, it doesn't resolve firm capacity issues and doesn't allow for future load growth. This option is rejected

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to establish a new primary substation	To mitigate the overload on both primaries, it is considered that this is best achieved by establishing a new primary substation in the vicinity of East Ord Industrial Estate on the outskirts of Berwick and integrating that with the existing 11 kV network to transfer standing demand from the existing site. As both sites are supplied by banked 33 kV circuits, the complexity of the 33 kV circuits cannot be extended to connect the new primary. Therefore, it is considered that the new primary will be connected by two new 33 kV circuits from Berwick GSP to the site. once integration is complete, the security of the system is improved as any one fault will leave a minimum of 4 transformers on load.
Option 1 to replace existing old transformers with higher rating new transformers (2 x 12/24 MVA) at North Road and The Loaning, and establish new 33 kV circuits to North Road	The existing 2 x 10 MVA old transformers at North Road and The Loading will each be replaced with new 2 x 12/24 MVA transformers. This will increase the firm capacity to 24 MVA. New 33 kV circuits are established from Berwick Grid to North Road primary. An overhead line fault will then leave a minimum of 3 transformers on load.
Do Nothing	Would significantly increase risk of quality of supply issues to customers in the Berwick area and may eventually would lead to a breach of requirements of EREC P2/6. This option has been rejected.
Establish new 33 kV OHL circuits from Berwick Grid to North Road primary	An overhead line fault will leave at least 3 primary transformers on load which provide the opportunity to make load transfers at the 11 kV side. However, it doesn't resolve firm capacity issues and doesn't allow for future load growth. This option is rejected

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	establish a new primary substation	Adopted							
1	to replace existing old transofrmers with higher rating new transformers (2 x 12/14 MVA) at North Road and The Loaning and establish new 33 kV OHL circuits to North Road	Rejected	based on cost		-£0.29	-£0.35	-£0.40	-£0.44	

Investment Business Case

CBA No.	33
Scheme/Project Name	SPD EHV-HV Gartferry Road
Scheme/Project Owner	Maloclm Bebbington
Primary Investment Objective	Facilitate demand growth
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	to equip Gartferry Road substation with 33/11 kV transformers and provide a 33 kV supply from Easterhouse.	Adopted
1	to equip Gartferry Road substation with 33/11 kV transformers and provide a 33 kV supply directly from Condorrat	Rejected

Background & Justification

Investment in the electricity distribution system in North Lanarkshire to facilitate demand growth.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - Equip Gartferry Road substation with 33/11kV transformers and provide a 33kV supply from Easterhouse – **Option Chosen**

It is proposed to equip the substation at Gartferry road and provide a 33 kV supply from Easterhouse GSP. This will require two new 33 kV feeder breakers to be installed at Easterhouse and new 33 kV circuits to be laid to Gartferry road. The existing 11 kV circuits will be ratained to provide interconneciton between Cumbernauld and Easterhouse GSPs.

This is an enduring solution to resolve quality of supply issues in the Gartferry Road area and provide interconnection between Cumbernauld and Easterhouse GSPs.

Option 1 - equip Gatferry Road substation with 33/11 kV transformer and provide a 33 kV supply directly from Condorrat

It is proposed to equip the substation at Gartferry road and provide a 33 kV supply from Condorrat.

Term (years from first out flow)	NPV (£m)
16	-£0.07
24	-£0.09
32	-£0.10
45	-£0.11
first year of investment out flow	5

Option 3: - Do nothing

Would significantly increase risk of quality of supply issues to customers in the Gartferry Road area and would breech Licence obligations under the ESQCR. This option has been rejected.

Appendix 1: Cost Benefit Analysis

Options considered	**Comment**
Baseline scenario to equip Gartferry Road substation with 33/11kV transformers and provide a 33kV supply from Easterhouse	It is proposed to equip the substation at Gartferry road and provide a 33 kV supply from Easterhouse GSP. This will require two new 33 kV feeder breakers to be installed at Easterhouse and new 33 kV circuits to be laid to Gartferry road. The existing 11 kV circuits will be ratained to provide interconneciton between Cumbernauld and Easterhouse GSPs. This is an enduring solution to resolve quality of supply issues in the Gartferry Road area and provide interconnection between Cumbernauld and Easterhouse GSPs.
Option 1 to equip Gatferry Road substation with 33/11 kV transformer and provide a 33 kV supply directly from Condorrat	It is proposed to equip the substation at Gartferry road and provide a 33 kV supply from Condorrat.
Do Nothing	Would significantly increase risk of quality of supply issues to customers in the Gartferry Road area and would breech Licence obligations under the ESQCR. This option has been rejected.

Option no.	**Options considered**	**Decision**	**Comment**	**Spend area (from Table C1) (relevant only to adopted option)**	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	to equip Gartferry Road substation with 33/11 kV transformers and provide a 33 kV supply from Easterhouse.	Adopted							
1	to equip Gartferry Road substation with 33/11 kV transformers and provide a 33 kV supply directly from Condorrat	Rejected	Rejected based on cost. Also significant risk due to thrust bore under motorway. This solution doesn't provide interconnection between Cumbernauld and Easterhouse GSPs		-£0.07	-£0.09	-£0.10	-£0.11	

Investment Business Case

CBA No.	34
Scheme/Project Name	Erskine Reinforcement
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Facilitate demand growth
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	to establish additional 33 kV circuits to a new primary substation in the vicinity of Bishopton	Adopted
I	to establish additional 33 kV circuits to a new primary substation in the vicinity of Inchinnan	Rejected

Background & Justification

Investment in the electricity distribution system in the Erskine area to facilitate demand growth.

Erskine 132/33 kV GSP has firm capacity of 30 MVA from transmission system supplying a single primary substation of three 12/24 MVA transformers with a firm capacity of 48 MVA. The site demand is approaching 30 MVA and the area is an increasingly developing area on the outskirts of Glasgow with commercial/industrial developments and the former ROD land being prepare for transfer for substantial housing development. Erskine, due to its geographic location on the south side of the River Clyde is isolated from infrastructure on the north side and is remote from, and with limited connection with, the adjacent Primary substation at Glasgow Airport, Port Glasgow and Kilmacolm. Therefore, any significant load growth development in the area constrained by the capacity limitations.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - establish additional 33kV circuits to a new primary substation in the vicinity of Bishopton – **Chosen Option**

The projected solution assumes an increase in transmission system connection capacity which could be a change of transformers from 30 MVA 132/33 kV units to 60 MVA or 90 MVA units. This work will be triggered by submission of a ModApp to the NETS So and it is anticipated that the only capital cost will be the application fee. Capital works will be funded by the TO and will be reflected in future exit charges.

The distribution works will be accomodated by establishing additional 33kV circuits to a new primary substation in the vicinity of Bishopton and some interconnection with the existing primary at Erskine. This therefore provides additional headroom across a wider area of the local network.

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*
Option 2 - establish additional 33 kV circuits to a new primary substation in the vicinity of Inchinnan

The projected solution assumes an increase in transmission system connection capacity which could be a change of transformers from 30 MVA 132/33 kV units to 60 MVA or 90 MVA units. This work will be triggered by submission of a ModApp to the NETS So and it is anticipated that the only capital cost will be the application fee. Capital works will be funded by the TO and wil be reflected in future exit charges.

The distribution works will be accomodated by establishing additional 33 kV circuits to a new primary substation in the vicinity of Inchinnan and some interconnection with the existing primary at Erskine. This therefore provides additional headroom across a wider area of the local network.

Term (years from first out flow)	NPV (£m)
16	-£0.27
24	-£0.34
32	-£0.38
45	-£0.43
first year of investment out flow	6

Option 3: - Do nothing

Any significant load growth development in the area will be constrained by the capacity limitations

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to establish additional 33kV circuits to a new primary substation in the vicinity of Bishopton	The projected solution assumes an increase in transmission system connection capacity which could be a change of transformers from 30 MVA 132/33 kV units to 60 MVA or 90 MVA units. This work will be triggered by submission of a ModApp to the NETS So and it is anticipated that the only capital cost will be the application fee. Capital works will be funded by the TO and will be reflected in future exit charges. The distribution works will be accomodated by establishing additional 33kV circuits to a new primary substation in the vicinity of Bishopton and some interconnection with the existing primary at Erskine. This therefore provides additional headroom across a wider area of the local network.
Option 1 to establish additional 33 kV circuits to a new primary substation in the vicinity of Inchinnan	The projected solution assumes an increase in transmission system connection capacity which could be a change of transformers from 30 MVA 132/33 kV units to 60 MVA or 90 MVA units. This work will be triggered by submission of a ModApp to the NETS So and it is anticipated that the only capital cost will be the application fee. Capital works will be funded by the TO and wil be reflected in future exit charges. The distribution works will be accomodated by establishing additional 33 kV circuits to a new primary substation in the vicinity of Inchinnan and some interconnection with the existing primary at Erskine. This therefore provides additional headroom across a wider area of the local network.
Do Nothing	Any significant load growth development in the area will be constrained by the capacity limitations

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	to establish additional 33 kV circuits to a new primary substation in the vicinity of Bishopton	Adopted							
1	to establish additional 33 kV circuits to a new primary substation in the vicinity of Inchinnan	Rejected	Rejected based on cost		-£0.27	-£0.34	-£0.38	-£0.43	

Investment Business Case

CBA No.	35
Scheme/Project Name	Lockerbie Voltage Support
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Resolve a voltage issue
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	to install a third 33 kV circuit between Chapelcross GSP and Lockerbie substation	Rejected
1	to install dynamic voltage support	Adopted

Background & Justification

Investment in the electricity distribution system in the Lockerbie area to resolve a voltage issue.

Lockerbie 33/11 kV substation is supplied via long 33 kV circuits from Chapelcross GSP which are both of the order of 17 km. At Lockerbie, a 33 kV busbar and disconnector arrangement provides a bussing point for the circuits and facilitates connection to the local primary substation and the two ongoing circuits to Moffat, with the No1 providing a tee connection into the single transformer priamry at Kirkbank.

Under a fault condition or a planned outage of either of the Chapelcross-Lockerbie 33 kV circuits, and arising from general load growth in the local network, both the 33 kV and 11 kV voltage following the outage are out with statutory limits. Recovery of the 11 kV busbar voltage within the tap changer range is problematic.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - install a third 33 kV circuits between Chapelcross GSP and Lockerbie substation

A fault condition or a planned outage of the Chapelcross-Lockerbie 33 kV circuits will keep at least two circuits remain in service. This will resolve the voltage issues.

Option 1 - install dynamic voltage support (SMART Solution) – **Option Chosen**

High level analysis indicates that solutions within the proximity of Lockerbie improve the condition but do not resolve within statutory limit. Conventional solutions would be to reduce the impedance to source by increasing the number of circuits or increasing conductor size or connect to another source.
However, Lockerbie is a very remote rural site with long circuit lengths to source and therefore conventional solutions will be problematic and expensive.
The projected solution is conisdered to be a dynamic shunt voltage support device which will provide up to +10 MVAr of reactive compensation. An optimum solution, including (where appropriate) the reactive compensation unit size and dynamic/fixed proportions, will be identified in the project development phase.

Term (years from first out flow)	NPV (£m)
16	**£1.04**
24	**£1.26**
32	**£1.41**
45	**£1.56**
first year of investment out flow	1

Option 2 – Do Nothing

Under a fault condition or a planned outage of either of the Chapelcross - Lockerbie 33 kV circuit, and arising from general load growth in the local network, both the 33 kV and 11 kV voltage following the outage are out with statutory limits

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to install a third 33 kV circuits between Chapelcross GSP and Lockerbie substation	A fault condition or a planned outage of the Chapelcross-Lockerbie 33 kV circuits will keep at least two circuits remain in service. This will resolve the voltage issues.
Option 1 to install dynamic voltage support (SMART Solution)	High level analysis indicates that solutions within the proximity of Lockerbie improve the condition but do not resolve within statutory limit. Conventional solutions would be to reduce the impedance to source by increasing the number of circuits or increasing conductor size or connect to another source. However, Lockerbie is a very remote rural site with long circuit lengths to source and therefore conventional solutions will be problematic and expensive. The projected solution is conisdered to be a dynamic shunt voltage support device which will provide up to +10 MVAr of reactive compensation. An optimum solution, including (where appropriate) the reactive compensation unit size and dynamic/fixed proportions, will be identified in the project development phase.
Do Nothing	Under a fault condition or a planned outage of either of the Chapelcross - Lockerbie 33 kV circuit, and arising from general load growth in the local network, both the 33 kV and 11 kV voltage following the outage are out with statutory limits

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	to install a third 33 kV circuit between Chapelcross GSP and Lockerbie substation	Rejected	Rejected based on cost						
1	to install dynamic voltage support	Adopted			£1.04	£1.26	£1.41	£1.56	

Investment Business Case

CBA No.	36
Scheme/Project Name	Langside Reinforcement
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Facilitate demand growth
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	to install a new primary substation in Hampton Park area	Rejected
1	to install active network management on the 11kV network to enable dynamic transfer of demand between substations.	Adopted

Background & Justification

Investment in the electricity distribution system in Langside, Rutherglen, South Lanarkshire to facilitate demand growth.

The maximum demand at Langside has for a number of years hovered around the substations firm capacity and in recent years has become more unpredictable in nature. The substation serves a mature, predominantly domestic network to the south of Glasgow and provides supplies to over 14,000 customers.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - install a new primary substation in Hampton Park area

Establish a new 33/11kV substation in the Hampton Park area, this will require two 12/24MVA transformers and a new 11kV switchboard. The new primary would be supplied by 33kV underground cables to Haggs Rd GSP (2x 3.2km).

Option 1 - install active network management on the 11kV network to enable dynamic transfer of demand between substations – **Option Chosen**

To develop an automation scheme which allows demand to be transferred to adjacent primary substations when the demand at Langside exceeds the firm capacity of the site.

Term (years from first out flow)	NPV (£m)
16	£2.06
24	£2.47
32	£2.78
45	£3.06
first year of investment out flow	6

Option 2 – Do Nothing

As demand increases this area of network may operate outside of the recommendations of ER P2/6.

Option 3 - replace transformers with 12/24 MVA units

Langside already has 21MVA units installed therefore capacity release would be fairly small. This option is not considered to offer value for money and has been discounted.

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to install a new primary substation in Hampton Park area	Establish a new 33/11kV substation in the Hampton Park area, this will require two 12/24MVA transformers and a new 11kV switchboard. The new primary would be supplied by 33kV underground cables to Haggs Rd GSP (2x 3.2km).
Option 1 to install active network management on the 11kV network to enable dynamic transfer of demand between substations. (Smart Solution)	To develop an automation scheme which allows demand to be transferred to adjacent primary substations when the demand at Langside exceeds the firm capacity of the site.
Do nothing	As demand increases this area of network may operate outside of the recommendations of ER P2/6.
replace transformers with 12/24 MVA units	Langside already has 21MVA units installed therefore capacity release would be fairly small. This option is not considered to offer value for money and has been discounted.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	to install a new primary substation in Hampton Park area	Rejected	Based on Cost						
1	to install active network management on the 11kV network to enable dynamic transfer of demand between substations.	Adopted	Based on Cost		£2.06	£2.47	£2.78	£3.06	

Investment Business Case

CBA No.	37
Scheme/Project Name	Berwick Ring Voltage Support
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Resolve a voltage issue
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	to establish new 33 kV circuits	Rejected
I	to install dynamic voltage support	Adopted

Background & Justification

Investment in the electricity distribution system to resolve a voltage issue on the 33 kV network fed from Berwick GSP.

The ‘Berwick 33kV Ring’ consists of a single 33kV circuit from Eccles to Berwick via Duns, Chirnside, Ayton and Eyemouth. The overall circuit length is significant at approximately 46km with the individual sections as follows:
Eccles–Duns: 13.6km; Duns–Chirnside: 9.2km; Chirnside–Ayton: 6.7km; Ayton–Eyemouth: 4.2km; Eyemouth–Berwick:12.4km.
With the distributed site demands and the significant circuit lengths, an outage of the first section from either GSP, results in the residual 33kV voltages being outwith statutory limits. Recovery of the 11kV busbar voltage within the tap changer range is becoming more problematic.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - establish new 33 kV circuits

Establish new circuits between Dun - Chirnside, Chirnside - Ayton and Eyemouth - Berwick. An outage of the first section from either GSP will not result in the residual 33 kV voltages being outside statutory limits.

Option 1 - install dynamic voltage support (Smart Solution) – **Option Chosen**

Given the exceedingly rural nature of this part of the network, analysis indicates that conventional solutions to reduce the impedance to source by increasing the number of circuits or increasing conductor size or connect to another source would be both expensive and problematic.

As the thermal capability of the circuits is adequate at this point in time and the primary issue is system voltage under single circuit outage conditions, the projected solution is considered to be dynamic voltage support at an appropriate point on the network. From an initial assessment of loads and circuit lengths, this is anticipated to be in the vicinity of Chirnside Switching / Primary Substation

The device will provide up to +20MVAr of reactive compensation and is likely to be located in the proximity of Duns or Chirnside.

Term (years from first out flow)	NPV (£m)
16	£0.84
24	£1.05
32	£1.18
45	£1.33
first year of investment out flow	1

Option 2 – Do Nothing

An outage of the first section from either GSP will result in the 33 kV voltages being outside statutory limits. This option has been rejected.

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline Scenario to establish new 33 kV circuits	Establish new circuits between Dun - Chirnside, Chirnside - Ayton and Eyemouth - Berwick. An outage of the first section from either GSP will not result in the residual 33 kV voltages being outside statutory limits.
Option 1 to install dynamic voltage support (Smart Solution)	Given the exceedingly rural nature of this part of the network, analysis indicates that conventional solutions to reduce the impedance to source by increasing the number of circuits or increasing conductor size or connect to another source would be both expensive and problematic. As the thermal capability of the circuits is adequate at this point in time and the primary issue is system voltage under single circuit outage conditions, the projected solution is considered to be dynamic voltage support at an appropriate point on the network. From an initial assessment of loads and circuit lengths, this is anticipated to be in the vicinity of Chirnside Switching / Primary Substation The device will provide up to +20MVAr of reactive compensation and is likely to be located in the proximity of Duns or Chirnside.
Do Nothing	An outage of the first section from either GSP will result in the 33 kV voltages being outside statutory limits. This option has been rejected.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	to establish new 33 kV circuits	Rejected	Rejected based on costs						
1	to install dynamic voltage support	Adopted			£0.84	£1.05	£1.18	£1.33	

Investment Business Case

CBA No.	38
Scheme/Project Name	Langholm Voltage Reinforcement
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Resolve a voltage issue
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	to establish new circuits from Chapelcross to Langholm	Rejected
1	to install dynamic voltage support	Adopted

Background & Justification

Investment in the electricity distribution system in Langholm area to resolve a voltage issue.

The 33kV system connecting Langholm 33kV switching station and Primary Substation consists of two single circuits on diverse routes from Chapelcross GSP. While circuit routes are divers, the circuit length are fairly well matched at 27km and 26km.

With the substation demand at around annual peak demand, due to the significant circuit lengths, an outage of one circuit during this time results in the residual 33kV voltages being outwith statutory limits. Recovery of the 11kV busbar voltage within the tap changer range is becoming more problematic.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - establish new circuits from Chapelcross to Langholm

Establish new circuits between Chapelcross and Langholm. An outage of one circuit will have another circuit remains in service and resolves the voltage issue.

Option 1 - install dynamic voltage support (SMART Solution) – **Option Chosen**

Given the exceedingly rural nature of this part of the network, analysis indicates that conventional solutions to reduce the impedance to source by increasing the number of circuits or increasing conductor size or connect to another source would be both expensive and problematic..

As the thermal capability of the circuits is adequate at this point in time and the primary issue is system voltage under single circuit outage conditions, the projected solution is considered to be dynamic voltage support at Langholm 33kV switching station.

The device will provide up to +20MVAr of reactive compensation and is likely to be connected at the 33kV switching station although an option would be an 11kV connection. .

Term (years from first out flow)	NPV (£m)
16	£1.82
24	£2.25
32	£2.57
45	£2.87
first year of investment out flow	5

Option 2 – Do Nothing

An outage of one circuit results in the residual 33 kV voltage being out of statutory limits.

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to establish new circuits from Chapelcross to Langholm	Establish new circuits between Chapelcross and Langholm. An outage of one circuit will have another circuit remains in service and resolves the voltage issue.
Option 1 to install dynamic voltage support (smart solution)	Given the exceedingly rural nature of this part of the network, analysis indicates that conventional solutions to reduce the impedance to source by increasing the number of circuits or increasing conductor size or connect to another source would be both expensive and problematic.. As the thermal capability of the circuits is adequate at this point in time and the primary issue is system voltage under single circuit outage conditions, the projected solution is considered to be dynamic voltage support at Langholm 33kV switching station. The device will provide up to +20MVAr of reactive compensation and is likely to be connected at the 33kV switching station although an option would be an 11kV connection. .
Do Nothing	An outage of one circuit results in the residual 33 kV voltage being out of statutory limits.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	to establish new circuits from Chapelcross to Langholm	Rejected	Rejected based on cost						
1	to install dynamic voltage support	Adopted	Cheaper and problem resolved. Smart solution is adopted		£1.82	£2.25	£2.57	£2.87	

Investment Business Case

CBA No.	39
Scheme/Project Name	Broxburn GSP Network Reconfiguration
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Facilitate demand growth and remove 33kV constraint
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	to establish two new 33 kV circuits to Digital subs	Adopted
1	to establish two new 33 kV circuits to South Queensferry	Rejected
2	Do nothing	Rejected

Background & Justification

Investment in the electricity distribution system in the Broxburn area to facilitate demand growth and remove an existing constraint from the 33 kV distribution network.

The current network configuration of the 33 kV circuits from Broxburn 132/33 kV substation results in three substation being supplied from only two 33 kV circuits. These circuits are currently rated at 20.86 MVA, whilst the summation of the maximum demands (undiversified) amounts over 27 MVA. With future load growth expected over the next price review period, this limits the ability of these substations to accept additional load without placing the 33 kV cicuits to unacceptable levels of overloading.

There also identified harmonic issues in this area of the network, which is evident to customers supplied from South Queensferry substation. Due to the harmonics being injected, there is limited capability at Broxburn to accept further (disturbing) loads to this part of the network.

Approach to the Options Appraisal

- *Option 1 is always a 'do minimum'/ Business as usual Option. All the costs and benefits associated with the other options are relative to the do minimum Option (Option 1).*
- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) – to establish two new 33 kV circuits to Digital subs

Chosen option

It is proposed to establish two new 33 kV circuits, approximately 9km in length from Broxburn GSP to the Digital Tee, which will then supply both Digial and South Queensferry 33/11 kV substations.

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*
Option 1 – to establish two new 33 kV circuits to South Queensferry

It is proposed to establish two new 33 kV circuits, approximately 10.5 km length from Broxburn GSP to the South Queensferry, which the existing line will supply both East Mains and Digital 33/11 kV substation, and the new circuits will supply South Queensferry 33/11 kV substation..

It has been assumed that a Rubber Glove Live Line team consists of 3 linesmen and will replace 2 poles per day.

Term (years from first out flow)	NPV (£m)
16	-£0.32
24	-£0.39
32	-£0.44
45	-£0.49
first year of investment out flow	3

Option 2 – Do nothing

This wil limits the ability of these substations to accept additional load without placing the 33 kV circuits to unacceptable level of overloadings.

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to establish two new 33 kV circuits to Digital subs	It is proposed to establish two new 33 kV circuits, approximately 9km in length from Broxburn GSP to the Digital Tee, which will then supply both Digial and South Queensferry 33/11 kV substations.
Option 1 to establish two new 33 kV circuits to South Queensferry	It is proposed to establish two new 33 kV circuits, approximately 10.5 km length from Broxburn GSP to the South Queensferry, which the existing line will supply both East Mains and Digital 33/11 kV substation, and the new circuits will supply South Queensferry 33/11 kV substation.
Do Nothing	This wil limits the ability of these substations to accept additional load without placing the 33 kV circuits to unacceptable level of overloadings.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	to establish two new 33 kV circuits to Digital subs	Adopted							
1	to establish two new 33 kV circuits to South Queensferry	Rejected	Rejected based on cost		-£0.32	-£0.39	-£0.44	-£0.49	
2	Do nothing	Rejected							

Investment Business Case

CBA No.	40
Scheme/Project Name	Ecclefechan Reinforcement
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Facilitate demand growth
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	to establish new 33 kV substation and "looping in" the two 33 kV circuits from Chapelcross to Lockerbie	Adopted
1	to establish new 33 kV substation without "looping in" the two 33 kV circuits from Chapelcross to Lockerbie	Rejected

Background & Justification

Investment in the electricity distribution system in Ecclefechan area to primarily facilitate demand growth but would also provide the opportunity for the connection of embedded generation connections in the areea.

Due to the sparse nature of the distribution infrastructure on the M74 corridor in South Lanarkshire/North Dumfriesshire, the acquisition of generation is problematic or load requires inefficient or disproportionate investment.

An additional transmission infeed is required to provide a system able to facilitate load and generation connections and improve quality of supply to the wider area

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) – establish new 33 kV substation and "looping in" the two 33 kV circuits from Chapelcross to Lockerbie **- Chosen Option**

The baseline scenario assumes an incremental transmission system connection at an appropriate location in the vicinity of Ecclefechan. Given the transmission assets in the vicinity, this is assumed to take the form of a 132/33 kV GSP with a capacity of 90 MVA in the proximity of the Ecclefechan Traction Supply to the West Coast Main Line. It is worthy of note that both 132kV circuits supplying this traction supply are single phase. This work will be triggered by submission of a ModApp to the NETS SO and it is anticipated that the only capital cost to SPD will be the Application Fee. Capital works will be funded by the TO and will be reflected in future exit charges

The distribution work will be accomodated by "looping in" the two 33 kV circuits from Chapelcross to Lockerbie and the single circuits to Stevens Croft and Minsca generators. This effectively moves demand (Lockerbie, Kirkbank and Moffat) and generation (Stevens Croft and Minsca) from Chaplecross to the new site. By looping into the existing circuits, interconnection is established with Chapelcross for mutual support.

Option 1 - establish new 33 kV substation without "looping in" the two 33 kV circuit from Chapelcross to Lockerbie

Same approach to baseline scenario, but instead of "looping in" the two 33 kV circuits from Chapelcross to Lockerbie, Lockerbie is directly supplied from the new 33kV Ecclefechan substation.

Term (years from first out flow)	NPV (£m)
16	-£1.33
24	-£1.63
32	-£1.85
45	-£2.06
first year of investment out flow	4

Option 2: - Do Nothing

The acquisition of generation and load remains problematic.

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to establish new 33 kV substation and "looping in" the two 33 kV circuits from Chapelcross to Lockerbie.	The baseline scenario assumes an incremental transmission system connection at an appropriate location in the vicinity of Ecclefechan. Given the transmission assets in the vicinity, this is assumed to take the form of a 132/33 kV GSP with a capacity of 90 MVA in the proximity of the Ecclefechan Traction Supply to the West Coast Main Line. It is worthy of note that both 132kV circuits supplying this traction supply are single phase. This work will be triggered by submission of a ModApp to the NETS SO and it is anticipated that the only capital cost to SPD will be the Application Fee. Capital works will be funded by the TO and will be reflected in future exit charges The distribution work will be accomodated by "looping in" the two 33 kV circuits from Chapelcross to Lockerbie and the single circuits to Stevens Croft and Minsca generators. This effectively moves demand (Lockerbie, Kirkbank and Moffat) and generation (Stevens Croft and Minsca) from Chaplecross to the new site. By looping into the existing circuits, interconnection is established with Chapelcross for mutual support.
Option 1 to establish new 33 kV substation without "looping in" the two 33 kV circuit from Chapelcross to Lockerbie	Same approach to baseline scenario, but instead of "looping in" the two 33 kV circuits from Chapelcross to Lockerbie, Lockerbie is directly supplied from the new 33kV Ecclefechan substation.
Do Nothing	The acquisition of generation and load remains problematic

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	to establish new 33 kV substation and "looping in" the two 33 kV circuits from Chapelcross to Lockerbie	Adopted							
1	to establish new 33 kV substation without "looping in" the two 33 kV circuits from Chapelcross to Lockerbie	Rejected	based on cost		-£1.33	-£1.63	-£1.85	-£2.06	

Investment Business Case

CBA No.	41
Scheme/Project Name	Dumfries
Scheme/Project Owner	Malcom Bebbington
Primary Investment Objective	Resolve a known fault at Dumfries 132/11kV substation
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	to supply the demand from new established 33/11 kV primary substation	Adopted
1	to supply the demand from adjacent existing 33/11 kV primary substation	Rejected

Background & Justification

Investment in the electricity distribution system to resolve a known fault level issue at Dumfries 132/11kv substation.

The Dumfries GSP consists of two discrete systems
- 132/33 kV GSP with three 60 MVA transformers, one of which is dedicated to the ICI connection and
- 132/11 kV GSP with two 30 MVA transformer

The 11 kV GSP has a demand of approximately 18 MVA but the transformation which effectively skips a voltage level (33 kV) results in an 11 kV fault level in excess of the plant capability and in excess of the 11 kV design fault level ceiling.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - to supply the demand from new established 33/11 kV primary substation – **CHOSEN**

It is considered that the projected solution to resolve the fault level issue at the 11 kV switchboard will be by eliminating the double voltage level transformation and removal of the 132/11 kV units. This could be achieved by establishing a 33/11 kV primary substation and supplying the demand currently derived from the 132/11 kV site from the new primary substation. Supply for the new primary substation will be derivedby extensions to the 33 kV switchboard.

Option 1 - remove 132/11 kV units, supply the secondary demand from Heathhall primary substation

It is considered that the projected solution to resolve the fault level issue at the 11 kV switchboard will be by eliminating the double voltage level transformation and removal of the 132/11 kV units. This could be achieved by supplying the demand currently derived from the 132/11 kV site from the adjacent primary substation. The existing circuits from 33 kV switchboard to adjacent primary substation need to be upgraded and 11 kV circuit reconfiguration would also be required.

Term (years from first out flow)	NPV (£m)
16	-£0.56
24	-£0.69
32	-£0.77
45	-£0.85
first year of investment out flow	1

Option 3: - Use fault current limiter (Smart Solution)

The development and effectiveness of fault current limiters being trialled in WPD networks will be closely monitored and this technology will be considered in future.

Option 4: - Do nothing

An 11 kV fault level remain in excess of the plant capability.

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to supply the demand from new established 33/11 kV primary substation	It is considered that the projected solution to resolve the fault level issue at the 11 kV switchboard will be by eliminating the double voltage level transformation and removal of the 132/11 kV units. This could be achieved by establishing a 33/11 kV primary substation and supplying the demand currently derived from the 132/11 kV site from the new primary substation. Supply for the new primary substation will be derivedby extensions to the 33 kV switchboard.
Option 1 remove 132/11 kV units, supply the secondary demand from Heathhall primary substation	It is considered that the projected solution to resolve the fault level issue at the 11 kV switchboard will be by eliminating the double voltage level transformation and removal of the 132/11 kV units. This could be achieved by supplying the demand currently derived from the 132/11 kV site from the adjacent primary substation. The existing circuits from 33 kV switchboard to adjacent primary substation need to be upgraded and 11 kV circuit reconfiguration would also be required.
Use fault current limiter (Smart Solution)	The development and effectiveness of fault current limiters being trialled in WPD networks will be closely monitored and this technology will be considered in future.
Do Nothing	An 11 kV fault level remain in excess of the plant capability.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	to supply the demand from new established 33/11 kV primary substation	Adopted							
1	to supply the demand from adjacent existing 33/11 kV primary substation	Rejected	Rejected based on cost		-£0.56	-£0.69	-£0.77	-£0.85	

Investment Business Case

CBA No.	42
Scheme/Project Name	Portobello 11kV Fault Level Resolution
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Resolve a known 11kV fault
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	to establish two standard separate primary substation each with a nominal firm capacity of 24 MVA.	Adopted
I	to establish three standard separate primary substation	Rejected

Background & Justification

Investment in the electricity distribution system in Portobello area to resolve a known 11kv fault level issue and faciltate demand growth.

The existing fault levels at Portobello 33/11 kV substation are operating in excess of the switchgear rating. Currently access restrictions are in place to mitigate the risks posed by operating in this manner. It is not possible to reduce the fault level by operating with a transformer on open standby due to the configuration of the 11 kV primary switchboards and the high demand served by this substation.

Portobello is equipped with three 33/11 kV trnasformers feeding three seperate 11kV switchboards in an un-conventional interconnected arrangement. The scope of this project is to develop the most appropriate solution to overcome the limitations posed by the existing network arrangement and thereby reduce the fault levels at this site.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - establish two standard separate primary substation each with a nominal firm capacity of 24 MVA – **Chosen Option**

The project solution is to establish two separate primary substations at Portbello to replace the current three transformer arrangement. As this will involve significant infrastructure works, the opportunity to smart enable the new distribution infrastructure which will be installed as part of the reinforcement/fault level mitigation scheme. THis will be achieved by installing, where appropruate:
- IEC 61580 Compliant Substation Devices (including protection devices)
- Dynamic Network Protection at 11 kV
- RMUs Fitted with Actuators
- Link boxes fitted with remote control and
- Communiations to and from devices

Option 1 - establish three standard separate primary substation

The project solution is to establish three separate primary substation at Portbello to replace the current three transformer arrangement.

Term (years from first out flow)	NPV (£m)
16	-£0.65
24	-£0.80
32	-£0.90
45	-£1.00
first year of investment out flow	1

Option 2 - Use fault current limiter (Smart Solution)
The development and effectiveness of fault current limiter used in WPD network will be closely monitored and this technology will be considered in the future

Option 3 – Do nothing
The existing fault level at Portobellow 33/11 kV substation remains in excess of the switchgear rating.

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to establish two standard separate primary substation each with a nominal firm capacity of 24 MVA.	The project solution is to establish two separate primary substations at Portbello to replace the current three transformer arrangement. As this will involve significant infrastructure works, the opportunity to smart enable the new distribution infrastructure which will be installed as part of the reinforcement/fault level mitigation scheme. THis will be achieved by installing, where appropruate: - IEC 61580 Compliant Substation Devices (including protection devices) - Dynamic Network Protection at 11 kV - RMUs Fitted with Actuators - Link boxes fitted with remote control and - Communiations to and from devices
Option 1 to establish three standard separate primary substation	The project solution is to establish three separate primary substation at Portbello to replace the current three transformer arrangement.
Use fault current limiter (Smart Solution)	The development and effectiveness of fault current limiter used in WPD network will be closely monitored and this technology will be considered in the future
Do Nothing	The existing fault level at Portobellow 33/11 kV substation remains in excess of the switchgear rating.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	to establish two standard separate primary substation each with a nominal firm capacity of 24 MVA.	Adopted							
1	to establish three standard separate primary substation	Rejected	Rejected based on cost		-£0.65	-£0.80	-£0.90	-£1.00	

Investment Business Case

CBA No.	43
Scheme/Project Name	Killermonth 33kV Fault Level Resolution
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Resolve known fault issue
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	replace existing board with a higher rating new board	Adopted
1	install two reactors in series with the GSP transformers	Rejected
2	install a bus-coupling reactor between the Killermont busbars	Rejected

Background & Justification

Investment in the electricity distribution system in Killermont area to resolve a known fault level issue.

The 33 kV board at Killermont Grid Supply Point (GSP) was commissioned in 1962 and the switchgear has an RMS break rating of 13.12 kA. The 33 kV fault level exceeds the equipment rating and hence the site is deemed overstressed. The fault level at Killermont GSP is significantly above equipment rating and site restriction are currently in place. It is proposed to change the board at the start of RIIO ED1 period.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

<u>**Business as Usual Option (Baseline) -** replace existing board with a higher rating new board – **Chosen Option**</u>

It is proposed to replace the 33 kV indoor board at Killermont GSP with a new indoor board of at least 17.5 kA RMS break rating to resolve the fault level issue and provide headroom for future demand growth and connection of embedded generation. The new board will comprise of eighteen panel for feeder breakers and bus section. The cost associated with environmental, engineering, civil and commissioning works will be included. It is proposed to build the new board offline.

<u>Option 1 - Install two reactors in series with the GSP transformers.</u>

This solution would install two series reactors and associated protection into the GSP transformer tails. This solution is seen as deferrment of replacing the existing switchboard. Given the age of the existing switchboard, it would likely require replacement before the end of the RIIO-ED1 price control period.

Term (years from first out flow)	NPV (£m)
16	-£0.23
24	-£0.41
32	-£0.55
45	-£0.69
first year of investment out flow	3

<u>Option 2: - install a bus-coupling reactor between the Killermont busbars</u>

This solution would install a bus coupling reactor and associated protection between the busbars at Killermont. This solution is seen as deferrment of replacing the existing switchboard. Given the age of the existing switchboard, it would likely require replacement before the end of the RIIO-ED1 price control period.

Term (years from first out flow)	NPV (£m)
16	-£0.05
24	-£0.22
32	-£0.34
45	-£0.46
first year of investment out flow	3

<u>Option 3 – Use fault current limiter(Smart Solution)</u>
The development and effectiveness of fault current limiter used in WPD network will be closely monitored and this technology will be considered in the future

<u>Option 4 – Replace grid transformers with high impedance transformers</u>
Not viable as this will increase long term losses significantly

<u>Option 5 – Do Nothing</u>
The 33 kV fault level will remain exceeding the equipment rating and the site remains overstressed

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to replace existing board with a higher rating new board	It is proposed to replace the 33 kV indoor board at Killermont GSP with a new indoor board of at least 17.5 kA RMS break rating to resolve the fault level issue and provide headroom for future demand growth and connection of embedded generation. The new board will comprise of eighteen panel for feeder breakers and bus section. The cost associated with environmental, engineering, civil and commissioning works will be included. It is proposed to build the new board offline.
Option 1 to install two reactors in series with the GSP transformers	This solution would install two series reactors and associated protection into the GSP transformer tails. This solution is seen as deferrment of replacing the existing switchboard. Given the age of the existing switchboard, it would likely require replacement before the end of the RIIO-ED1 price control period.
Option 2 to install a bus-coupling reactor between the Killermont busbars	This solution would install a bus coupling reactor and associated protection between the busbars at Killermont. This solution is seen as deferrment of replacing the existing switchboard. Given the age of the existing switchboard, it would likely require replacement before the end of the RIIO-ED1 price control period.
Use fault current limiter (Smart Solution)	The development and effectiveness of fault current limiter used in WPD network will be closely monitored and this technology will be considered in the future
Replace grid transformers with high impedance	Not viable as this will increase long term losses significantly
Do nothing	The 33 kV fault level will remain exceeding the equipment rating and the site remains overstressed

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	replace existing board with a higher rating new board	Adopted							
1	install two reactors in series with the GSP transformers	Rejected	Based on Cost		-£0.23	-£0.41	-£0.55	-£0.69	
2	install a bus-coupling reactor between the Killermont busbars	Rejected	Based on Cost		-£0.05	-£0.05	-£0.05	-£0.05	

Investment Business Case

CBA No.	44
Scheme/Project Name	West George Street 33kV Fault Level Resolution
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Resolve a known fault
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	replace existing 33 kV indoor boards, A Board and B Board at West George Street GSP	Adopted
1	to replace existing 33 kV indoor boards at West George Street GSP with new boards built offline.	Rejected

Background & Justification

Investment in the electricity distribution system in West George Street area to resolve a known fault level issue.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - replace existing 33 kV indoor boards, A Board and B Board at West George Street GSP – **Option Chosen**

It is proposed ot replace the existing 33kV indoor boards, A Board and B Board, at West George Street GSP with two new indoor board of at least 25 kA RMS break rating to resolve the fault issue and provide headroom for future demand growth. The boards will comprise of twenty four panels for distribution feeder breakers, and bus sections. The associated environmental, engineering, civil and commissioning works are to be included. The replacement of the 33 kV boards at West George Street GSP will be extremely challenging due to its location and space limitation.

Option 1 - replace existing 33 kV indoor boards at West George Street GSP with new boards built offline.

Same as baseline scenario but with a new board built offline.

Term (years from first out flow)	NPV (£m)
16	-£0.10
24	-£0.13
32	-£0.14
45	-£0.16
first year of investment out flow	4

Option 2: - Use fault current limiter (Smart Solution)

The development and effectiveness of fault current limiter used in WPD network will be closely monitored and this technology will be considered in the future

Option 3: - Replace grid transformer with high impedance transformer

Not viable as this will increase long term losses significantly

Option 4: - Do nothing

The 33 kV fault level remain exceeding the equipment raitng and the site remains overstressed

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to replace existing 33 kV indoor boards, A Board and B Board at West George Street GSP	It is proposed ot replace the existing 33kV indoor boards, A Board and B Board, at West George Street GSP with two new indoor board of at least 25 kA RMS break rating to resolve the fault issue and provide headroom for future demand growth. The boards will comprise of twenty four panels for distribution feeder breakers, and bus sections. The associated environmental, engineering, civil and commissioning works are to be included. The replacement of the 33 kV boards at West George Street GSP will be extremely challenging due to its location and space limitation.
Option 1 to replace existing 33 kV indoor boards at West George Street GSP with new boards built offline.	Same as baseline scenario but with a new board built offline.
Use fault current limiter (Smart Solution)	The development and effectiveness of fault current limiter used in WPD network will be closely monitored and this technology will be considered in the future
Replace grid transformer with high impedance transformer	Not viable as this will increase long term losses significantly
Do Nothing	The 33 kV fault level remain exceeding the equipment raitng and the site remains overstressed

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	replace existing 33 kV indoor boards, A Board and B Board at West George Street GSP	Adopted							
1	to replace existing 33 kV indoor boards at West George Street GSP with new boards built offline.	Rejected	Rejected based on cost		-£0.10	-£0.13	-£0.14	-£0.16	

Investment Business Case

CBA No.	45
Scheme/Project Name	Girvan Voltage Reinforcement
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Resolve a voltage issue
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	to establish new circuit from Girvan substation to Maybole GSP	Rejected
1	to install dynamic voltage support	Adopted

Background & Justification

Investment in the electricity distribution system in Girvan area toresolve a voltage issue.

33/11 kV substation is supplied via 33 kV circuits from Maybole GSP which are 13 km and 16 km long. an, a 33 kV busbar and disconnector arrangement which supplies the single transformer primary tion at Pinwherry. The Pinwherry connection is assigned to either the No1 or No 2 side such that an ad line fault will result in loss of a 33/11 kV transformer at Girvan and the sole 33/11 kV unit at rry. Under these circumstances, the 11 kV demand at Pinwherry is switched automatically onto the ing Girvan 33/11 kV transformer.

Arising from general load growth in the area, both the 33 kV and 11 kV voltages following the outage are outside statutory limits. Recovery of the 11 kV busbar voltage within the tap changer range is problematic.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) establish new circuit from Girvan substation to Maybole GSP

Establish new circuits between Girvan substation to Maybole GSP. An outage of one circuit will have another circuit remains in service and resolves the voltage issue. .

Option 1 - install dynamic voltage support (SMART Solution) – **Option Chosen**

Analysis indicates that solutions within the proximity of Girvan improve the conditions but do not resolve within statutory limits. Conventional solutions would be to reduce the impedance of source by increasing the number of circuits or increasing conductor size or connect to another source.

However, Girvan is a remote rural site with long circuit lengths to source and therefore conventional solutions will be problematic and expensive.

The projected solution is considered to be a dynamic shunt voltage support device which will provide up to + 10 MVAr of reactive compensation.

Term (years from first out flow)	NPV (£m)
16	£1.47
24	£1.80
32	£2.02
45	£2.25
first year of investment out flow	3

Option 2 – Do Nothing

An outage of one circuit results in the residual 33 kV and 11 kV voltage being out of statutory limits.

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to establish new circuit from Girvan substation to Maybole GSP	Establish new circuits between Girvan substation to Maybole GSP. An outage of one circuit will have another circuit remains in service and resolves the voltage issue.
Option 1 to install dynamic voltage support (smart solution)	Analysis indicates that solutions within the proximity of Girvan improve the conditions but do not resolve within statutory limits. Conventional solutions would be to reduce the impedance of source by increasing the number of circuits or increasing conductor size or connect to another source. However, Girvan is a remote rural site with long circuit lengths to source and therefore conventional solutions will be problematic and expensive. The projected solution is considered to be a dynamic shunt voltage support device which will provide up to + 10 MVAr of reactive compensation.
Do Nothing	An outage of one circuit results in the residual 33 kV and 11 kV voltage being out of statutory limits.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	to establish new circuit from Girvan substation to Maybole GSP	Rejected	Rejected based on cost						
1	to install dynamic voltage support	Adopted	Cheaper and problem resolved. Smart solution is adopted		£1.47	£1.80	£2.02	£2.25	

Investment Business Case

CBA No.	46
Scheme/Project Name	Stranraer
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	Resolve a voltage issue
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	to establish new circuit from Stranraer primary substation to Glenluce GSP	Rejected
I	to install dynamic voltage support	Adopted

Background & Justification

Investment in the electricity distribution system in Stranraer area to resolve a voltage issue.

Stranraer 33/11 kV substation is supplied via 33 kV circuits from Glenluce GSP which are 13.7 km and 15 km long.

Arising from general load growth in the area, both the 33 kV and 11 kV voltage following an outage are close to being outside statutory limits. Recovery of the 11 kV busbar voltage within the tap changer range is becoming more problematic as the demand increases.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - establish new circuit from Stranraer primary substation to Glenluce GSP

Establish new circuit between Stranraer substation to Glenluce GSP. An outage of one circuit will have another circuit remains in service and resolves the voltage issue.

Option 1 - install dynamic voltage support (SMART Solution) – **Option Chosen**

Analysis indicates that solutions within the proximity of Stranraer improve the condition but do not resolve within statutory limits. Conventional solutions would be to reduce the impedance source by increasing the number of circuits or increasing conductor size or connect to another source. However, Stranraer is a remote rural site with long circuit lengths to source and therefore conventional solutions will be problematic and expensive. The projected solution is considered to be a dynamic shunt voltage support device which provide up to + 12 MVAr of reactive compensation.

Term (years from first out flow)	NPV (£m)
16	£1.01
24	£1.25
32	£1.42
45	£1.59
first year of investment out flow	4

Option 2 – Do Nothing

An outage of one circuit results in the residual 33 kV and 11 kV voltage being out of statutory limits.

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario to establish new circuit from Stranraer primary substation to Glenluce GSP	Establish new circuit between Stranraer substation to Glenluce GSP. An outage of one circuit will have another circuit remains in service and resolves the voltage issue.
Option 1 to install dynamic voltage support (smart solution)	Analysis indicates that solutions within the proximity of Stranraer improve the condition but do not resolve within statutory limits. Conventional solutions would be to reduce the impedance source by increasing the number of circuits or increasing conductor size or connect to another source. However, Stranraer is a remote rural site with long circuit lengths to source and therefore conventional solutions will be problematic and expensive. The projected solution is considered to be a dynamic shunt voltage support device which provide up to + 12 MVAr of reactive compensation.
Do Nothing	An outage of one circuit results in the residual 33 kV and 11 kV voltage being out of statutory limits.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	to establish new circuit from Stranraer primary substation to Glenluce GSP	Rejected	Rejected based on costs						
1	to install dynamic voltage support	Adopted	Cheaper and problem resolved. Smart solution is adopted		£1.01	£1.25	£1.42	£1.59	

Investment Business Case

CBA No.	47
Scheme/Project Name	Smart Meter Rollout
Scheme/Project Owner	Fiona Fulton
Primary Investment Objective	
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
1	Holistic Smart Data Infrastructure	Adopted
1.1	sensitivity	
1.2	sensitivity	
2	Smart Meter Only Data Infrastructure	Rejected
3		
4		
5		

Background & Justification

Determine the optimum level of support for smart meter data use within the business to improve fault resolution, better design choices and improved customer services. It must also ensure we meet all of our Smart Energy Code obligations.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Chosen Option – (Option 1) - Holistic Smart Data Infrastructure

An option to do nothing is not viable as no current solution exists. The baseline option fulfills our SEC licence requirements for connection to the DCC and storage of appropriate smart meter information only. Further use of smart meter data within the business would largely be by manual analysis.
This option would leverage a shared smart data infrastructure to allow smart meter data to be delivered to operational and non-operatiional systems for use in day to day business processes. The infrastructure would also be used by other smart grid and monitoring activities, allowing future savings in infrastructure costs.

Term (years from first out flow)	NPV (£m)
16	£38.12
24	£33.46
32	£29.34
45	£23.69
first year of investment out flow	1

Sensitivity Option 1.1 - 10% YoY DCC cost increase

Term (years from first out flow)	NPV (£m)
16	£37.35
24	£32.11
32	£27.41
45	£20.89
first year of investment out flow	1

Sensitivity Option 1.2 - 30% reduction in lossess avoided

Term (years from first out flow)	NPV (£m)
16	£33.69
24	£29.03
32	£24.91
45	£19.27
first year of investment out flow	1

<u>Option 2 - Smart Meter Only Data Infrastructure</u>

Term (years from first out flow)	NPV (£m)
16	£32.42
24	£24.79
32	£18.62
45	£10.79
first year of investment out flow	1

This option would develop infrastructure specific to smart meters and used only by smart meter data. It would attempt to achieve the same benefits as option 1 but would take no account of wider smart grid requirements. This would lead to faster deployment but higher costs.

Appendix 1 - Cost Benefit Analysis (Excel Spreadsheet) Attached

Options considered	Comment
"do minimum" option	An option to do nothing is not viable as no current solution exists. The baseline option fulfills our SEC licence requirements for connection to the DCC and storage of appropriate smart meter information only. Further use of smart meter data within the business would largely be by manual analysis
Option 1	This option would leverage a shared smart data infrastructure to allow smart meter data to be delivered to operational and non-operatiional systems for use in day to day business processes. The infrastructure would also be used by other smart grid and monitoring activities, allowing future savings in infrastructure costs.
Option 2	This option would develop infrastructure specific to smart meters and used only by smart meter data. It would attempt to achieve the same benefits as option 1 but would take no account of wider smart grid requirements. This would lead to faster deployment but higher costs.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	BCR
1	Holistic Smart Data Infrastructure	Adopted			£38.12	£33.46	£29.34	£23.69	2.6
1.1	sensitivity		10% YoY DCC cost increase		£37.35	£32.11	£27.41	£20.89	
1.2	sensitivity		30% reduction in lossess avoided		£33.69	£29.03	£24.91	£19.27	
2	Smart Meter Only Data Infrastructure	Rejected			£32.42	£24.79	£18.62	£10.79	
3									
4									
5									

Investment Business Case

CBA No.	48
Scheme/Project Name	132kV OHL Conductor
Scheme/Project Owner	Alyn Jones
Primary Investment Objective	To compare delivery strategies for 132kV steel tower overhead line conductor, Tension Stringing, Catenary Blocking, Drop/Recover and Replace. This CBA does not cover the whole steel tower moderisation programme, whihc extedns to insulators, fittings and tower steelwork. Nor dose it cost the impact on other Load and Non Load investment programmes.
Secondary Investment Objective (Engineering)	

Base line	Patch and continue	Rejected
1	Tension Stringing	Adopted
2	Catenary Blocking low tension	Rejected
2a	Catenary Blocking low tension/ Drop, recover and replace.	Rejected
3	Drop, recover and replace.	Rejected

Background & Justification

To compare delivery strategies for 132kV steel tower overhead line conductor, Tension Stringing, Catenary Blocking, Drop/Recover and Replace. This CBA does not cover the whole steel tower moderisation programme, whihc extedns to insulators, fittings and tower steelwork. Nor dose it cost the impact on other Load and Non Load investment programmes.

Contributes to our loss reduction strategy - Only impact SPM in Scotland 132kV is SPT licence

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline) - Patch and Continue (reactive repair)

Ruled out due to volume of ageing conductor, and requirement to operate a safe network under ESQCR, and impact of increasing age of conductor beyound its electrical life.

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*
Option 1 - Tension Stringing

This option represents continuation of the SPEN investment strategy commenced in DPRC5, but increases programme by 25% to accommodate the asset age and condition profile. Takes into account holistic delivery model, co-ordinated with other asset moderisation work.

Term (years from first out flow)	NPV (£m)
16	-£1.67
24	£7.13
32	£12.87
45	£19.40
first year of investment out flow	1

Option 2 - Catenary Blocking low tension

This option represents deferred investment approach equating to 4 years, compared to the current SPEN Investment Strategy, reflects a cross over to an increased unit cost of delivery, increases risk of asset failure. Does not include requirement to face additional standalone work programmes for insulators/fittings, nor impact on other dependent asset replacement activities in ED1

Term (years from first out flow)	NPV (£m)
16	£0.88
24	£8.32
32	£13.09
45	£18.47
first year of investment out flow	1

Option 2a - Catenary Blocking low tension/ Drop, recover and replace

This option represents deferred investment approach equating to 4 years, compared to the current SPEN Investment Strategy, reflects a cross over to an increased unit cost of delivery, increases risk of asset failure. Does not include requirement to face additional standalone work programmes for insulators/fittings nor impact on other dependent asset replacement activities in ED1

Term (years from first out flow)	NPV (£m)
16	£3.52
24	£9.24
32	£12.80
45	£16.81
first year of investment out flow	1

Option 3: Drop, recover and replace

This option represents deferred investment approach equating to 7 years compared to the current SPEN Investment Strategy, reflects a cross over to an increased unit cost of delivery, increases risk of asset failure. Does not include requirement to face additional standalone work programmes for insulators/fittings nor impact on other dependent asset replacement activities in ED1

Term (years from first out flow)	NPV (£m)
16	-£0.15
24	£2.33
32	£3.18
45	£4.20
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Patch and Continue (reactive repair)	Ruled out due to volume of ageing conductor, and requirement to operate a safe network under ESQCR, and impact of increasing age of conductor beyound its electrical life.
Tension Stringing	Adopted option as best option to meet SPEN Asset Strategy and dovetails with wider Non load and load related expenditire in ED1, to allow efficent expenditure, optimase system security and reduce impact on customers and stakeholders.
OP2 - Catenary Blocking low tension	Ruled out as although marginally more positive NPV than Option 1, for conductor replacement taken in isolation, we would not achieve the full volume requirement to extended outages/delivery time. This option also does not take into account the impact that
OP2a Catenary Blocking low tension & Drop/Recover	Ruled out as has a marginally less positive NPV than Option 1 for conductor replacement in isolation, and would meet the required ED1 volumes, in doing so this programme would run to the end of ED2, whihc would push the age of the targetted circuits in ED2 well beyound asset life, and mean we were failing our ESQCR commitments.
Op3 Drop, recover and replace.	Ruled out as significanlty less positive NPV than Option 1 due to volume of ageing conductor, and requirement to operate a safe network under ESQCR.

List below the short list of those options which have been costed within this CBA workbook

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Base line	Patch and continue		Ruled out due to ageing conductor and associated risk						
1	Tension Stringing	Adopted	Adopted as most economic long term solution		-£1.67	£7.13	£12.87	£19.40	
2	Catenary Blocking low tension		Rejected as lower NPV in long term		£0.88	£8.32	£18.47	£18.47	
2a	Catenary Blocking low tension/ Drop, recover and replace.		Rejected as lower NPV in long term		£3.52	£9.24	£0.00	£16.81	
3	Drop, recover and replace.		Rejected as lower NPV		-£0.15	£2.33	£1.00	£4.20	
4									

Investment Business Case

CBA no	49
Scheme/Project Name	Tree cutting to ENATS 43-08.
Scheme/Project Owner	Iain Divers
Primary Investment Objective	To manage vegetation within safety distance of overhead lines
Secondary Investment Objective (Engineering)	Improve public safety and fault performance

Option no.	Options considered	Decision
1	Baseline scenario: 3 year tree cutting cycle	Adopted
2	1 year tree cutting cycle	Rejected
3	5 year tree cutting cycle	Rejected

Approvals

	Name(s)	Date
Engineering Review	Jeff Hunt/ Peter Sherwood	
Regulation Review	Scott Mathieson	
Business Sign-Off	Jim Sutherland	
ED1 Sign-Off	Scott Mathieson	

Background & Justification

Vegetation management forms a fundamental part of our overall risk based management regime for overhead lines, and is critical to maintaining legal, safety and performance requirements.

The ESQC regulations stipulate the legal requirement to establish and maintain clearances from our bare wire overhead line conductors and vegetation, typically trees, to ENATS (ENA Technical Specification) 43-08. Our policy is to cyclically inspect and cut vegetation in proximity to the overhead line network at a rate which ensures safety clearances are not compromised, in a cost efficient manner such that the network performance is maintained and satisfies our customers, landowners and other stakeholders.

We have encountered many challenges when developing our tree management cycles. Prominently, especially in parts of our SPM area, there can be refusals to cut trees from landowners, or legal challenges (such as Tree Preservation Orders). This tends to be in rural areas and villages, on the basis of visual amenity. 'Restricted cuts' occur where we have to manage some of these locations on a more frequent basis, outside of our cycle.

Variability in cycle frequency also impacts the extent cut to accommodate anticipated growth rates. If vegetation is allowed to encroach near to our bare wire conductors then we have to switch off the supplies to allow tree cutting to proceed safely. This has knock on impacts on customer service and our operational resources. Unmanaged growth also increases the likelihood of inadvertent contact with ourlines, impacting our fault rates.

We have progressively optimised our cycle frequency and believe that the current three year cycle has demonstrated clear benefits in terms of cost, fault performance, delivery and safety. It allows us to manage the growth rates within programmed works, minimising the risks posed by re-growth rates, and reducing the extent of our cuts which benefits the visual amenity in populated areas. Our approach is supported by our stakeholders.

Our ENATS 43-08 tree cutting plans for ED1 amount to £99.9m across both our license areas.

Approach to the Options Appraisal

Assumptions

- This analysis is based on the SPD HV network.
- The entire HV network length has been considered.
- A 24 year (three price review) period has been assessed to provide a long term view.
- The average cost of inspection and cutting on the SPD HV network using a 3 year cycle approach is approximately £338 per km (excluding operational requirements, e.g. outages, legal issues, etc.).
- There are 298 non-conformances on the SPD HV network. The extent of these cannot be easily clarified, so for simplification these are assumed to be equivalent to 1 km each.
- Assumed reactive cost of managing these cuts outside of a cycle is assumed to be £667.
- Typical fault rate per 100km of HV overhead line network is 10.8. Average customers affected are 143 and average duration is 157 minutes.
- No impact has been modelled for costs of maintaining ETR132 cuts (risk baesd approach to

managing trees to within falling distance).

Baseline (Business as Usual) Scenario:
3 year tree cutting cycle

SPD have been inspecting and cutting trees on the HV network based on a 3 year cycle throughout DPCR5. This approach is well established and is supported by our stakeholders. Contracts are stable and resources are well established. Expected growth rates vary according to species, but can frequently be between 1 and 1.5m per annum. Instances of non-conformance exist, but are managed.

Option 1:
1 year tree cutting cycle

Increasing ENATS 43-08 inspections and cuts to an annual basis will virtually remove all non-conformances. By default, every span will have minimal cuts and be managed yearly. This will reduce visual impact, which can be the key issue in many cases.

Increasing the cycle to this rate will pose a significant resource challenge, especially considering the current position of a three year cycle. Contracted service partners will have to provide more skilled, experienced staff with suitable authorisations. Despite the decrease in the extent of cuts on site, the setup costs will result in increased rates and costs will not be 'spread' across reporting years.

Fault rates can be reduced by more frequent inspections and management, but many tree-related issues which impact typical fault rates (excluding severe weather events) are already managed in a three year cycle. It is expected that there will be marginal benefits in fault performance.

Term (years from first out flow)	NPV (£m)
16	-£11.83
24	-£26.38
32	-£38.58
45	-£51.46
first year of investment out flow	1

Option2:
5 year cycle

Decreasing the cycle frequency to five years will spread the costs over five years instead of three. Unit costs will be expected to decrease as there is less pressure on resources, although cuts on site will be to a further extent to account for the additional growth. This will impact on non-conformance issues, which are anticipated to increase as we are challenged on the impact on visual amenity.

With less frequent inspections there are additional risks posed from fast growing trees and vegetation, or from sites that are now within a five year cycle but were cut for three years. This will result in an increase in fault rates, and a consequential decrease in performance and customer service. More outages will be required for planned work, however this has not been modelled.

Term (years from first out flow)	NPV (£m)
16	-£10.06
24	-£9.87
32	-£7.89
45	-£5.80
first year of investment out flow	1

Sensitivities

N/A

Appendix 1: Cost Benefit Analysis

Options considered	Comment
BASELINE: 3 year cycle	SPEN operates a 3 year cyclic tree inspection/cutting programme across its distribution overhead line networks. This is specificied under ENATS 43-08. There is no specific frequency of cycle that DNOs must comply with, but public safety, cost and fault performance are the key drivers that we have used to optimise our cycle. Due to the nature of vegetation proximity and use in some areas there can be difficulties in obtaining consents to establish safety cuts. If cuts cannot be established, they can fall outwith the cycle and lead to 'reactive' cuts, which cost more to maintain. There may be additional costs resulting from managing cuts outwith a cycle, particularly if they can encroach on live conductors - e.g. customer outages, generators, compensation, etc.
1 year cycle	Increasing the frequency to a 1-year cycle would remove the need for 'reactive' cuts, but have a consequential impact on tree cutting resources - i.e. trained personnel, authorisations, etc. This would have a significant impact on unit cost. However, this would remove all non-conformance issues, as minimal cuts would be required to achieve safety (to accommodate 1 year's worth of growth only). This would only have a marginal impact on faults, as tree related fault rates have already been significantly attenuated with the baseline 3 year cycle, and this CBA does not consider cutting trees to within falling distance as per ETR132.
5 year cycle	Decreasing the cycle frequency to 5 years would reduce the resource requirements for contractors and thus reduce the unit cost. There would be a resultant increase in non-conformances, as an additional 2 years of growth (at approximately 1 - 1.5m expected growth per annum) would have to be accommodated; there would be an increase in landowners reluctant to provide consent for these more sgnificant cuts. The volumes of faults due to trees is expected to increase in this scenario, as there is a longer timeframe for an undiscovered issues to impact the network. If regrowth rates are not managed to their required extent then more outages will be required to cut within proximity to live conductors. This will have a consequential impact on customer service, geneartor costs and operational staff.

Option no.	Options considered	Decision	Comment	NPVs based on payback periods				
				16 years	24 years	32 years	45 years	DNO view
1	Baseline scenario: 3 year tree cutting cycle	Adopted		£0.00	£0.00	£0.00	£0.00	
2	1 year tree cutting cycle	Rejected	Rejected due to significant increase in cost with marginal gain in performance/safety	-£11.83	-£26.38	-£38.58	-£51.46	
3	5 year tree cutting cycle	Rejected	Rejected due to increase in costs	-£10.06	-£9.87	-£7.89	-£5.80	

Investment Business Case

CBA no	50
Scheme/Project Name	Storm Resilience
Scheme/Project Owner	Iain Divers
Primary Investment Objective	To achieve a storm resilient 11kV overhead line network.
Secondary Investment Objective (Engineering)	Replace existing 11kV overhead main lines whose design limitations are below that of the expected weather conditions.

Option no.	**Options considered**	**Decision**
Baseline	Baseline scenario: Rebuild overhead line to new storm resilient specification and cut trees to ETR132 methodology	Adopted
1	Rebuild overhead line to new specification but do not cut trees to ETR132	Rejected
2	Refurbish the overhead line only	Rejected
3	Underground the overhead line	Rejected

Background & Justification

Our HV wood pole infrastructure supplies electricity to domestic, commercial and industrial customers in our SPD and SPM license areas allowing power flow and interconnection for security of supply. A significant proportion of this network was constructed in the 1950s and 1960s and is now performing less efficiently, safely and reliably.

Following the effects of severe storms in the late 1990s and early 2000s, we initiated industry leading programmes to clear trees from our overhead line networks and modernise the overhead line network. From our experience, we consider 'storm resilience' to cover two key areas: capability to withstand wind loading and ice accretion on conductors/poles, and cutting of trees within falling distance as per industry standard methodology ETR132.

We have assessed the prevailing conditions across our network through MET office-developed maps and developed a new suite of OHL installation specifications which are deemed to be 'Fit for Purpose' for these areas. An independent storm review undertaken by KEMA [1], assessing empirical overhead line network performance, confirmed a '10 fold' reduction in fault rate during storms on circuits which have been engineered to be storm resilient. This was borne out in January 2012, when the network withstood the storm and had 76% fewer faults than was suffered when an identical storm hit the network in December 1998.

Our continuing strategy from DPCR5 is to rebuild 11kV lines to a resilient, 'fit for purpose' specification based on an assessment of condition, specification and weather area. Our long term objective is that by 2034 40% of interconnected 11kV main lines will be rebuilt to a storm resilient standard with ETR132 tree cutting, such that a severe weather event should not affect any connected customer for more than 36 hours. This policy was recognized as industry leading by PB Power.

To achieve this, we will:

- Rebuild 0.8% of the 11kV network (2.0% of main lines) annually to a fit for purpose specification taking into account the land topography and prevailing severe and normal weather patterns.

In tandem with this programme, in ED1 we will also continue our DPCR5 strategy of a rolling 12-year refurbishment cycle, which covers our entire 11kV overhead line asset base. This will maintain network performance and mange our aging assets through ED1. To achieve this we will:

- Refurbish 7.2% of the 11kV network annually to improve the network (including reconductoring 11kV spur lines with poorly performing steel and Simalec conductors

Our stakeholders have told us that they value further improvement in storm resilience, stating that they would be willing to pay more for us delivering improved resilience to between 10 and 11.5% of customers.

This modernisation strategy for the 11kV overhead line network accounts for £141.3m of total ED1 Business Plan spend.

[1] KEMA Report G07-1652 February 2007, Iain Wallace: An Assessment of HV Overhead Storm Resilience.

Approach to the Options Appraisal

Assumptions

- The cost of building an 11kV overhead main line to a storm resilient specification is £39.31K per km.
- To make the numbers meaningful, 100 km has been considered rather than just 1 km.
- All rebuilt lines will have tree cut in accordance with ENA ETR 132.
- The average cost for a circuit to achieve ETR 132 compliance is £9K per km.
- Follow up tree cutting to maintain ETR 132 compliance shall take place every 3 years.
- The kilometre rate for tree cuttings inclusive of carrying out surveying and obtaining permissions, (inclusive of staff Authorised to receive a Permit for Work and to erect overhead line earths, where required) is £657.14.
- In order to maintain an acceptable fault rate, the line will be refurbished every 12 years.
- The expected lifespan of a creosoted wood pole is approx 63 years ± 13 years.
- The baseline view of the circuit is that the condition/specification is such that it is a candidate for rebuild, with average wood pole of approx. 40 years.
- Base refurbishment costs are £5k per km.
- For newly built lines, the refurb cost will be proportionally lower immediately following rebuild. This will increase to the nominal refurb cost of £5k over three periods of refurbishment.
- Due to wood pole and conductor degradation over the 45 year life span, it is assumed that these will need incremental replacement over this lifespan (above that considered within refurbishment base cost). As specific rates of degradation/failure cannot be determined, an average is assumed.
- Baseline fault rates have been taken from NAFIRS tables.
- When an overhead line is storm resilient rebuilt, including to ETR 132, it is assumed that there will be a 90% reduction in certain types of faults (e.g. wear and tear and wind borne material) but no reduction in other faults (e.g. third party damage or lightning). Overall there will be a 65.39% reduction in faults.
- When an overhead line is refurbished, less fault producing categories are affected and there will be only an 80% reduction in those. Overall, there will be a 39.26%
- It is assumed that on lines that are not rebuilt to a storm resilient standard, there will be a resultant increase in faults and associated costs annually as a result of severe weather impacts. Several of these events are typically experienced every year in both licence areas, however, the type (wind/ice/snow), extent and timing of these cannot be forecast. Therfore an average has been assumed.
- SPD customer information has been used for this CBA; however, although there a slight differences between the SPD and the SPM data, this does not cause any material difference to the analysis.
- The cost benefit analysis is based on the SPD severe weather areas, while the main lines of normal weather areas will also be rebuilt to an appropriate design specification for the environment, this will be a lower cost that the design specification for the severe weather areas and therefore the outcome of the analysis will show a greater benefit in rebuilding the overhead line rather than undergrounding the network.

Baseline (Business as Usual) Scenario:
Rebuild to 'fit for purpose' specification and tree cutting to ETR132

Ensuring a circuit is fully storm resilient is most effectively achieved through a coordinated approach to vegetation management and construction of overhead lines to a standard that is suitable for the weather environment where it is erected. The robust specification will not only withstand storms but will also suffer from fewer faults than refurbished lines over the first 20 years. Once built to a suitable specification, the line will be refurbished every 12 years and the tree resilience maintained with cutting taking place every 3 years. Note: 100km has been considered for this CBA.

Option 1:
Rebuild to 'fit for purpose' specification, but with no ETR132 tree cutting

Rebuilding a line to a modern, 'fit for purpose' specification will ensure it is resilient for prevailing weather conditions in terms of the line's components only, such as ice accretion and wind loading on conductors. However, by not including tree cutting as per the ETR132 methodology then the line is not resilient against trees within falling distance and associated windborne debris. Although the frequency and composition of future storms cannot be predicted, during DPCR5 we have experienced multiple severe weather events every year, with a high proportion primarily wind storms. Fault performance outwith storms will be broadly unaffected. The circuit will be refurbished as per the 12 year cycle. Tree cutting to ENATS 43-08 will continue every 3 years.

Term (years from first out flow)	NPV (£m)
16	-£0.20
24	-£0.47
32	-£0.90
45	-£1.61
first year of investment out flow	1

Option 2:
Refurbish 11kV main line

Our refurbishment strategy is to improve network performance and manage the deterioration of our overhead line assets in a rolling 12 year cycle. This improves performance and replaces 'end of life' assets, such as HI.5 poles.

The main line sample under consideration is a designs that is no longer suitable for the prevailing weather conditions expected in the area. ENA Technical Specification 43-40 details the ice and wind loadings that can be expected throughout the country taking height into account. Refurbishment does not provide storm resilience, as assets are only replaced/maintained, leaving the specification of the circuit unaffected. ENATS 43-08 tree cutting is standard.

Due to the 45 year timescales, it is anticipated that the overhead line sample under consideration – the condition/specification of which drives the baseline rebuild scenario – would essentially require incremental rebuild over this time period, driving up the refurbishment cost. Leaving this volume of components to run until failure would negatively impact customer performance.

Term (years from first out flow)	NPV (£m)
16	-£0.93
24	-£1.90
32	-£2.94
45	-£4.56
first year of investment out flow	1

Option 3:

Underground 11kV Overhead Main Line

Replacement of the 11kV overhead main line with an underground cable. The payback periods under consideration are all less that the estimated time frame of when the cable will start to deteriorate, so there will be no faults associated with this scenario.

This avoids all fault impacts associated with overhead lines, including storms, and avoids the necessity for tree cutting.

Term (years from first out flow)	NPV (£m)
16	-£2.94
24	-£3.30
32	-£3.47
45	-£3.50
first year of investment out flow	1

Sensitivities

N/A

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario: Rebuild 11kV main lines to a storm resilient specification and cut trees to ETR132 methodology	This is most effectively achieved through a coordinated approach to vegetation management and construction of overhead lines to a standard that is suitable for the weather environment where it is erected. An independent storm review looking at empirical overhead line network performance has shown a '10' fold reduction in fault rate during storms on circuits which have been engineered to be storm resilient. The robust specification will not only withstand storms but will also suffer from less faults than refurbished lines over the first 20 years. Once built to a suitable specification, the line will be refurbished every 12 years and the tree resilience maintained with cutting taking place every 3 years. Note: 100km of main line has been considered for this CBA, with the line considered to be approx 35 years old.
Rebuild 11kV main lines to a storm resilient construction without ETR 132 tree cutting.	Although achieving ETR 132 tree compliance is an integral component of the storm resilient overhead line construction, this portion could be detatched from the specification. This would result in increased faults due to growing or falling trees and windborne material, resulting in a greater number of faults and longer restoration times particularly during storms. The line would still be considered resilient to ice accretion/wind loading during storm events.
Refurbishment of 11kV main line	Refurbishment of 11kV lines forms our strategy for managing performance and component degradation until the circuit is rebuilt. In ED1 we plan to continue our rolling 12 year cycle for refurbishment. The main lines under consideration are to designs that are no longer suitable for the environment in which they are built. In recent years, storms have typically become more frequent and more severe. ENA Technical Specification 43-40 details the ice and wind loadings that can be expected throughout the country taking height into account. Additionally, our refurbishment unit costs are based on the refurbishing lines that are generally fit for purpose. For this CBA, the baseline considers a circuit that is due for rebuild based on condition and a specification that is not 'fit for purpose'. To provide a meaningful comparison, the rebuild scenario would have to cover - at a minimum - the replacement of all 'end of life' poles during this 45 year timescale. This is in addition to the baseline unit cost for refurbishment. Refurbished lines are not considered 'storm resilient' in our plans, and so would be subject to the impacts of wind/ice storms, of which we have had on average 5 p.a. through DPCR5.
Undergrounding of 11kV main line	Replacement of the 11kV overhead main line with an underground cable. The payback periods under considreation are all less that the estimated time frame of when the cable will start to deteriorate, so there will be no faults associated with this scenario.

Option no.	Options considered	Decision	Comment	NPVs based on payback periods				
				16 years	24 years	32 years	45 years	DNO view
Baseline	Baseline scenario: Rebuild overhead line to new storm resilient specification and cut trees to ETR132 methodology	Adopted	Most economic option	£0.00	£0.00	£0.00	£0.00	
1	Rebuild overhead line to new specification but do not cut trees to ETR132	Rejected	Rejected due to negative NPV	-£0.20	-£0.47	-£0.90	-£1.61	
2	Refurbish the overhead line only	Rejected	Rejected due to negative NPV	-£0.93	-£1.90	-£2.94	-£4.56	
3	Underground the overhead line	Rejected	Rejected due to negative NPV	-£2.94	-£3.30	-£3.47	-£3.50	

Investment Business Case

CBA no	51.1
Scheme/Project Name	11kV Civils
Scheme/Project Owner	L. Speakman
Primary Investment Objective	The primary driver of this investment decision is to meet ESQC regulations, ensure our substations are safe for staff/public and to minimise electical plant failures due to poor environmental conditions

Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
B	Carry out civil programme based on trending of key investment drivers for roofs, doors and fences	Adopted
I	As above, however do not replace substation roofs during ED1	Rejected

Background & Justification

The primary driver of this investment decision is to meet ESQC regulations, ensure our substations are safe for staff/public and to minimise electical plant failures due to poor environmental conditions

Approach to the Options Appraisal

Baseline (Business as Usual) Scenario:

Carry out civil programme based on trending of key investment drivers for roofs, doors and fences

Option 1:

As above, however do not replace substation roofs during ED1

Term (years from first out flow)	NPV (£m)
16	-£7.84
24	-£10.61
32	-£12.92
45	-£16.19
first year of investment out flow	1

Sensitivities

N/A

Appendix 1: Cost Benefit Analysis

Options considered / project name	Comment
Baseline	Carry out civil programme based on trending of key investment drivers for roofs, doors and fences
Option 1	As above, however do not replace substation roofs during ED1

List below the short list of those options which have been costed within this CBA workbook

Option no.	Options considered	Decision	Comment	For the chosen option only, provide detail of where CBA expenditure included in this CBA is reported in the BPDT pack. e.g. LV swtichgear BPDT CV3 rows 15 to 22.	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
B	Carry out civil programme based on trending of key investment drivers for roofs, doors and fences	Adopted	Most economic option	CV6 - Line 14 & 15					
1	As above, however do not replace substation roofs during ED1	Rejected	Least economic option		-£2.04	-£2.93	-£3.77	-£5.13	
4									
5									

Investment Business Case

CBA no	51.2
Scheme/Project Name	33kV Civils
Scheme/Project Owner	Lee Speakman
Primary Investment Objective	The primary driver of this investment decision is to meet ESQC regulations, ensure our substations are safe for staff/public and to minimise electical plant failures due to poor environmental conditions
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
B	Carry out civil programme based on findings of civil surveys - Renew/Refurb HI 4/5 civil assets and ensure the substation is safe and secuire & environment is condicive to maxmising the life and performance of indoor assets	Adopted
1	Carry out civil programme based on findings of` civil surveys - Renew//Refurb all assets showing signs of decay and ensure the substation is safe & environment is condicive to maxmising the life and performance of indoor assets	Rejected
2	As above, however carry out all defects and remedial actions as stipulated in civil surveys Carry out civil programme based on findings of civil surveys - Renew/Refurb HI 4/5 civil assets and Carry out civil programme based on findings of civil surveys - Renew/Refurb HI 4/5 civil assets and ensure the substation is safe and secuire, however do not replace substations roofs through ED1	Rejected

Background & Justification

The primary driver of this investment decision is to meet ESQC regulations, ensure our substations are safe for staff/public and to minimise electical plant failures due to poor environmental conditions

Approach to the Options Appraisal

<u>Baseline (Business as Usual) Scenario:</u>

Carry out civil programme based on findings of civil surveys - Renew/Refurb HI 4/5 civil assets and ensure the substation is safe and secuire & environment is condicive to maxmising the life and performance of indoor assets

<u>Option 1:</u>

Carry out civil programme based on findings of civil surveys - Renew//Refurb all civil assets showing signs of decay and ensure the substation is safe & environment is condicive to maxmising the life and performance of indoor assets

Term (years from first out flow)	NPV (£m)
16	-£4.50
24	-£5.75
32	-£6.59
45	-£7.46
first year of investment out flow	1

<u>Option2:</u>
Carry out civil programme based on findings of civil surveys - Renew/Refurb HI 4/5 civil assets and ensure the substation is safe and secure, however do not replace substations roofs through ED1

Term (years from first out flow)	NPV (£m)
16	-£3.33
24	-£4.45
32	-£5.36
45	-£6.60
first year of investment out flow	1

Sensitivities

N/A

Appendix 1: Cost Benefit Analysis

List below all options considered to meet the stated aim

Options considered / project name	Comment
Baseline	Carry out civil programme based on findings of civil surveys - Renew/Refurb HI 4/5 civil assets and ensure the substation is safe and secuire & environment is condicive to maxmising the life and performance of indoor assets
Option 1	Carry out civil programme based on findings of civil surveys - Renew//Refurb all civil assets showing signs of decay and ensure the substation is safe & environment is condicive to maxmising the life and performance of indoor assets
Option 2	Carry out civil programme based on findings of civil surveys - Renew/Refurb HI 4/5 civil assets and ensure the substation is safe and secure, however do not replace substations roofs through ED1

List below the short list of those options which have been costed within this CBA workbook

Option no.	Options considered	Decision	Comment	For the chosen option only, provide detail of where CBA expenditure included in this CBA is reported in the BPDT pack. e.g. LV swtichgear BPDT CV3 rows 15 to 22.	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
B	Carry out civil programme based on findings of civil surveys - Renew/Refurb HI 4/5 civil assets and ensure the substation is safe and secuire & environment is condicive to maxmising the life and performance of indoor assets	Adopted	Most economic option	CV6 - Line 15					
1	Carry out civil programme based on findings of` civil surveys - Renew//Refurb all assets showing signs of decay and ensure the substation is safe & environment is condicive to maxmising the life and performance of indoor assets	Rejected	Least economic option		-£4.50	-£5.75	-£6.59	-£7.46	
2	As above, however carry out all defects and remedial actions as stipulated in civil surveys Carry out civil programme based on findings of civil surveys - Renew/Refurb HI 4/5 civil assets and Carry out civil programme based on findings of civil surveys	Rejected	Least economic option		-£3.33	-£4.45	-£5.36	-£6.60	
4									
5									

Investment Business Case

CBA No.	52
Scheme/Project Name	Lister Drive 132kV AIS GIS
Scheme/Project Owner	Lee Speakman
Primary Investment Objective	Replacement of HI5 132kV bulk oil breakers at Lister Grid substation. In addition to this the disconnectors and civil structures are showing significant signs of deterioration
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
B	**AIS inline rebuild**	**Rejected**
1	**GIS offline rebuild**	Adopted
2	**Replace OCB's with GCB**	Rejected
3	AIS off line rebuild	Rejected

Background & Justification

This CBA sets out the case to replace outdoor AIS switchgear within an indoor GIS solution rather than refurbish or replace with a AIS solution. Our 132kV investment plan is to replace Lister Drive, Birkenhead, Crewe, Speke and Gateacre with GIS solutions. Our other large substation at Rainhill will be replacedlike for like with AIS.

The Primary Driver of this investment decision is the replacement of HI5 132kV bulk oil breakers at Lister Grid substation. In addition to this the disconnectors and civil structures are showing significant signs of deterioration

CBA Overview

The objective of this CBA is to analyse the lifecycle costs and risks associated with each investment scenario considered. Costs are disaggregated into the following categories:-

- Construction costs
- Network risk
- Civil/electrical maintenance costs
- Fault costs

Construction costs

Cost includes project management, material procurement, commissioning of new site and demolition and making good of abandoned site as required.

- **GIS** costs are based on a detailed scheme design and costing for the project.
- **AIS Inline Rebuild** costs are based on the detailed scheme design and costing for an AIS Inline Rebuild solution at Kirkby Grid. Assumed 8% uplift on base price due to reduced efficiency and controlled removal of structures.
- **AIS Refurb** – stage 1, based on replacing existing OCB with GCB, renewal of multicores and refurbishment of isolators and civil structures in poor condition. Assumed 25% uplift on base price due to prelims and project management. Stage 2 is based on an AIS Inline refurb cost, less the cost of works incurred in stage 1.

Outage Risks - CI & CML

One of the significant differentiators of risk for the options considered is during the commissioning of busbar protection systems following the replacement of circuit breakers and associated equipment such as multicores and relays. When replacing OCB with GCB's in-situ there is a risk of either disturbing existing protection small wiring or human error could result in the busbar protection scheme tripping leading to a total loss of the site.

Lister Drive Grid is a NGC in feed for the group with a total customer interruption impact of 170,000 customers, restoration time for all customers affected is assumed 120 minutes. For each scenario a probability of occurrence is assigned to derive an overall CI/CML risk which is used in the models.

The second highest differentiator of risk relates to construction activities within a live open busbar compound. An operator may inadvertently come in to contact, or damage electrical plant, protection or control systems resulting in the busbar protection operating; again a total loss of site is assumed. For each scenario a probability of occurrence is assigned to derive an overall CI/CML risk which is used in the models.

Electrical Maintenance costs

The ongoing electrical maintenance costs for each option are based on the frequency stated in our Plant Maintenance Policy SUB-01-009, unit costs are based on our ED1 forecast. The maintenance costs considered are for the 132kV circuit breakers and associated disconnectors / earth switches.

Civil Maintenance cost

The civil maintenance costs for each option considered is based on the ground maintenance costs of each solution and includes chipping and periodic weed suppression for outdoor sites. For the Indoor GIS site, provision has been made to paint the external cladding of the building 25 years after it construction.

Annual Reliability cost

The annual reliability cost considers the ongoing costs of unplanned maintenance to plant. For each asset an annual probability of failure for each health index band and mean time to repair (MTTR) in hours is assigned. The annual cost is a function of the MTTR and POF. For the purpose of analysis it is assumed the asset will degrade linearly through each HI band over its life.

Business as Usual Option (Baseline) - AIS inline rebuild

AIS inline rebuild starting in 2015 and completed by 2020. The CBA considers the construction costs, outage risk and ongoing civil and electrical maintainance of the site.

- Costs based on average cost per bay for Kirkby Grid inline AIS Scheme
- Assume 8% uplift on scheme costs due to controlled dismantling of existing structured in live compound
- Assume 0.084 chance of bus zone trip due to protection commisioning resulting in 170,000 customers off supply for 180 minutes
- Assume 0.072 chance of bus zone trip due to inadvertant contact or damage of electrical plant / systems during construction resulting in 170,000 customers off supply for 180 minutes

Option 1 - GIS offline rebuild – **Chosen Option**

GIS offline rebuild starting in 2019 and completed by 2020. The CBA considers the construction costs, outage risk and ongoing civil and electrical maintainance of the site.

- Costs based on detailed scheme design.
- Assume 0.018 chance of bus zone trip due to protection commisioning resulting in 170,000 customers off supply for 180 minutes
- Assume 0.006 chance of bus zone trip due to inadvertant contact or damage of electrical plant / systems during construction resulting in 170,000 customers off supply for 180 minutes

Lowest risk to network during construction. Reduce ongoing H&S risks associated with AIS sites.

Term (years from first out flow)	NPV (£m)
16	£2.57
24	£2.78
32	£2.93
45	£3.11
first year of investment out flow	1

Option 2: - Replace OCB's with GCB

Replace OCB's with GCB, renew multicores and refurbish isolators to give a 10 year life extension start 2015 and complete in 2016. Following this carry out AIS inline rebuild utilising existing GCB's starting in 2025, completed by 2028. The CBA considers the construction costs, outage risk and ongoing civil and electrical maintainance of the site.

- Costs based on average cost per bay for Kirkby Grid inline AIS Scheme.
- Assume 8% uplift on scheme costs due to controlled dismantling of existing structured in live compound.
- Costs for stage one OCB to GCB retrofit includes disconnector and civil refurbishment refurbishment. 25% uplift for prelims and project management.
- Assume 0.055 (stage 1) and 0.048 (stage 2) chance of bus zone trip due to protection commisioning resulting in 170,000 customers off supply for 180 minutes.
- Assume 0.048 (stage 1) and 0.060 (stage 2) chance of bus zone trip due to inadvertant contact or damage of electrical plant / systems during construction resulting in 170,000 customers off supply for 180 minutes.

Higher risk to network and constrains other network activies due to extended outages per circuit.

Term (years from first out flow)	NPV (£m)
16	£1.07
24	£0.69
32	£0.43
45	£0.12
first year of investment out flow	1

Option 3: - AIS off line rebuild

Not availible due to space constraints.

Appendix 1: Cost Benefit Analysis

Options considered / project name	Comment
Baseline	AIS inline rebuild starting in 2015 and completed by 2020. The CBA considers the construction costs, outage risk and ongoing civil and electrical maintainance of the site.
Option 1	GIS offline rebuild starting in 2019 and completed by 2020. The CBA considers the construction costs, outage risk and ongoing civil and electrical maintainance of the site.
Option 2	Replace OCB's with GCB, renew multicores and refurbish isolators to give a 10 year life extension start 2015 and complete in 2016. Following this carry out AIS inline rebuild utilising existing GCB's starting in 2025, completed by 2028. The CBA considers the construction costs, outage risk and ongoing civil and electrical maintainance of the site.
Option 3	AIS off line rebuild

List below the short list of those options which have been costed within this CBA workbook

Option no.	Options considered	Decision	Comment	For the chosen option only, provide detail of where CBA expenditure included in this CBA is reported in the BPDT pack. e.g. LV swtichgear BPDT CV3 rows 15 to 22.	sed on payback periods				
					16 years	24 years	32 years	45 years	DNO view
B	**AIS inline rebuild**	**Rejected**							
1	**GIS offline rebuild**	Adopted	Most economic option	**BPDT CV3 - Row 92,98,102 & BPDT CV6 - Row 33,34,35**	£2.57	£2.79	£2.93	£3.11	
2	**Replace OCB's with GCB**	Rejected	least economic option		£1.07	£0.69	£0.43	£0.12	
3	AIS off line rebuild	Rejected	Not availible due to space constraints						

Investment Business Case

CBA No.	53
Scheme/Project Name	Crewe
Scheme/Project Owner	Lee Speakman
Primary Investment Objective	Replacement of HI5 132kV bulk oil breakers at Crewe Grid substation.
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	AIS inline rebuild	Rejected
1	**GIS offline rebuild**	Adopted
2	Replace OCB's with GCB	Rejected
3	AIS off line rebuild	Rejected

Background & Justification

This CBA sets out the case to replace outdoor AIS switchgear within an indoor GIS solution rather than refurbish or replace with a AIS solution. Our 132kV investment plan is to replace Lister Drive, Birkenhead, Crewe, Speke and Gateacre with GIS solutions. Our other large substation at Rainhill will be replacedlike for like with AIS.

The Primary Driver of this investment decision is the replacement of HI5 132kV bulk oil breakers at Crewer Grid substation. In addition to this the disconnectors and civil structures are showing significant signs of deterioration.

CBA Overview

The objective of this CBA is to analyse the lifecycle costs and risks associated with each investment scenario considered. Costs are disaggregated into the following categories:-

- Construction costs
- Network risk
- Civil/electrical maintenance costs
- Fault costs

Construction costs

Cost includes project management, material procurement, commissioning of new site and demolition and making good of abandoned site as required.

- **GIS** costs are based on a detailed scheme design and costing for the project.
- **AIS Inline Rebuild** costs are based on the detailed scheme design and costing for an AIS Inline Rebuild solution at Kirkby Grid. Assumed 8% uplift on base price due to reduced efficiency and controlled removal of structures.
- **AIS Refurb** – stage 1, based on replacing existing OCB with GCB, renewal of multicores and refurbishment of isolators and civil structures in poor condition. Assumed 25% uplift on base price due to prelims and project management. Stage 2 is based on an AIS Inline refurb cost, less the cost of works incurred in stage 1.

Outage Risks - CI & CML

One of the significant differentiators of risk for the options considered is during the commissioning of busbar protection systems following the replacement of circuit breakers and associated equipment such as multicores and relays. When replacing OCB with GCB's in-situ there is a risk of either disturbing existing protection small wiring or human error could result in the busbar protection scheme tripping leading to a total loss of the site.

Crewe Grid is a 132kV switching station supplying apprximatley 90,000 customers, restoration time for all customers affected is assumed 120 minutes. For each scenario a probability of occurrence is assigned to derive an overall CI/CML risk which is used in the models.

The second highest differentiator of risk relates to construction activities within a live open busbar compound. An operator may inadvertently come in to contact, or damage electrical plant, protection or control systems resulting in the busbar protection operating; again a total loss of site is assumed. For each scenario a probability of occurrence is assigned to derive an overall CI/CML risk which is used in the models.

Electrical Maintenance costs

The ongoing electrical maintenance costs for each option are based on the frequency stated in our Plant Maintenance Policy SUB-01-009, unit costs are based on our ED1 forecast. The maintenance costs considered are for the 132kV circuit breakers and associated disconnectors / earth switches.

Civil Maintenance cost

The civil maintenance costs for each option considered is based on the ground maintenance costs of each solution and includes chipping and periodic weed suppression for outdoor sites. For the Indoor GIS site, provision has been made to paint the external cladding of the building 25 years after it construction.

Annual Reliability cost

The annual reliability cost considers the ongoing costs of unplanned maintenance to plant. For each asset an annual probability of failure for each health index band and mean time to repair (MTTR) in hours is assigned. The annual cost is a function of the MTTR and POF. For the purpose of analysis it is assumed the asset will degrade linearly through each HI band over its life.

Business as Usual Option (Baseline) - AIS inline rebuild

AIS inline rebuild starting in 2015 and completed by 2020. The CBA considers the construction costs, outage risk and ongoing civil and electrical maintainance of the site.

- Costs based on average cost per bay for Kirkby Grid inline AIS Scheme
- Assume 8% uplift on scheme costs due to controlled dismantling of existing structured in live compound
- Assume 0.068 chance of bus zone trip due to protection commisioning resulting in 90,000 customers off supply for 180 minutes
- Assume 0.059 chance of bus zone trip due to inadvertant contact or damage of electrical plant / systems during construction resulting in 90,000 customers off supply for 180 minutes

Option 1 - GIS offline rebuild – **Chosen Option**

GIS offline rebuild starting in 2019 and completed by 2020. The CBA considers the construction costs, outage risk and ongoing civil and electrical maintainance of the site.

- Costs based on detailed scheme design.
- Assume 0.015 chance of bus zone trip due to protection commisioning resulting in 90,000 customers off supply for 180 minutes
- Assume 0.005 chance of bus zone trip due to inadvertant contact or damage of electrical plant / systems during construction resulting in 90,000 customers off supply for 180 minutes

Lowest risk to network during construction. Reduce ongoing H&S risks associated with AIS sites

Term (years from first out flow)	NPV (£m)
16	£0.78
24	£0.67
32	£0.61
45	£0.56
first year of investment out flow	1

Option 2: - Replace OCB's with GCB

Replace OCB's with GCB, renew multicores and refurbish isolators to give a 10 year life extension start 2015 and complete in 2016. Following this carry out AIS inline rebuild utilising existing GCB's starting in 2025, completed by 2028. The CBA considers the construction costs, outage risk and ongoing civil and electrical maintainance of the site.

- Costs based on average cost per bay for Kirkby Grid inline AIS Scheme.
- Assume 8% uplift on scheme costs due to controlled dismantling of existing structured in live compound.
- Costs for stage one OCB to GCB retrofit includes disconnector and civil refurbishment refurbishment. 25% uplift for prelims and project management.
- Assume 0.045 (stage 1) and 0.039 (stage 2) chance of bus zone trip due to protection commisioning resulting in 90,000 customers off supply for 180 minutes.
- Assume 0.039 (stage 1) and 0.49 (stage 2) chance of bus zone trip due to inadvertant contact or damage of electrical plant / systems during construction resulting in 90,000 customers off supply for 180 minutes.

Term (years from first out flow)	NPV (£m)
16	£1.32
24	£0.97
32	£0.73
45	£0.46
first year of investment out flow	1

Option 3: - AIS off line rebuild

Not availible due to space constraints - rejected on engineering grounds

Appendix 1: Cost Benefit Analysis

Options considered / project name	**Comment**
Baseline	AIS inline rebuild starting in 2015 and completed by 2020. The CBA considers the construction costs, outage risk and ongoing civil and electrical maintainance of the site.
Option 1	GIS offline rebuild starting in 2019 and completed by 2020. The CBA considers the construction costs, outage risk and ongoing civil and electrical maintainance of the site.
Option 2	Replace OCB's with GCB, renew multicores and refurbish isolators to give a 10 year life extension start 2015 and complete in 2016. Following this carry out AIS inline rebuild utilising existing GCB's starting in 2025, completed by 2028. The CBA considers the construction costs, outage risk and ongoing civil and electrical maintainance of the site.
Option 3	AIS off line rebuild

List below the short list of those options which have been costed within this CBA workbook

Option no.	**Options considered**	**Decision**	**Comment**	**For the chosen option only, provide detail of where CBA expenditure included in this CBA is reported in the BPDT pack. e.g. LV swtichgear BPDT CV3 rows 15 to 22.**	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
B	**AIS inline rebuild**	**Rejected**							
1	**GIS offline rebuild**	Adopted	Most economic option over lifetime of the asset	**BPDT CV3 - Row 92,98,102 & BPDT CV6 - Row 33,34,35**	£0.78	£0.67	£0.61	£0.56	
2	**Replace OCB's with GCB**	Rejected	Least economic option over lifetime of the asset		£1.32	£0.97	£0.73	£0.46	
3	AIS off line rebuild	Rejected	Not availible due to space constraints						

Investment Business Case

CBA No.	54
Scheme/Project Name	Birkinhead 132kV
Scheme/Project Owner	Lee Speakman
Primary Investment Objective	Replacement of HI5 132kV bulk oil breakers at Birkenhead Grid substation.
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
B	**AIS inline rebuild**	**Rejected**
1	**GIS offline rebuild**	Adopted
2	**Replace OCB's with GCB**	Rejected
3	AIS off line rebuild	Rejected

Background & Justification

This CBA sets out the case to replace outdoor AIS switchgear within an indoor GIS solution rather than refurbish or replace with a AIS solution. Our 132kV investment plan is to replace Lister Drive, Birkenhead, Crewe, Speke and Gateacre with GIS solutions. Our other large substation at Rainhill will be replacedlike for like with AIS.

The Primary Driver of this investment decision is the replacement of HI5 132kV bulk oil breakers at Birkenhead Grid substation. In addition to this the disconnectors and civil structures are showing significant signs of deterioration

CBA Overview

The objective of this CBA is to analyse the lifecycle costs and risks associated with each investment scenario considered. Costs are disaggregated into the following categories:-

- Construction costs
- Network risk
- Civil/electrical maintenance costs
- Fault costs

Construction costs

Cost includes project management, material procurement, commissioning of new site and demolition and making good of abandoned site as required.

- **GIS** costs are based on a detailed scheme design and costing for the project.
- **AIS Inline Rebuild** costs are based on the detailed scheme design and costing for an AIS Inline Rebuild solution at Kirkby Grid. Assumed 8% uplift on base price due to reduced efficiency and controlled removal of structures.
- **AIS Refurb** – stage 1, based on replacing existing OCB with GCB, renewal of multicores and refurbishment of isolators and civil structures in poor condition. Assumed 25% uplift on base price due to prelims and project management. Stage 2 is based on an AIS Inline refurb cost, less the cost of works incurred in stage 1.

Outage Risks - CI & CML

One of the significant differentiators of risk for the options considered is during the commissioning of busbar protection systems following the replacement of circuit breakers and associated equipment such as multicores and relays. When replacing OCB with GCB's in-situ there is a risk of either disturbing existing protection small wiring or human error could result in the busbar protection scheme tripping leading to a total loss of the site.

Birkenhead Grid is a NGC in feed for the group with a total customer interruption impact of 125,000 customers, restoration time for all customers affected is assumed 120 minutes. For each scenario a probability of occurrence is assigned to derive an overall CI/CML risk which is used in the models.

The second highest differentiator of risk relates to construction activities within a live open busbar compound. An operator may inadvertently come in to contact, or damage electrical plant, protection or control systems resulting in the busbar protection operating; again a total loss of site is assumed. For each scenario a probability of occurrence is assigned to derive an overall CI/CML risk which is used in the models.

Electrical Maintenance costs

The ongoing electrical maintenance costs for each option are based on the frequency stated in our Plant Maintenance Policy SUB-01-009, unit costs are based on our ED1 forecast. The maintenance costs considered are for the 132kV circuit breakers and associated disconnectors / earth switches.

Civil Maintenance cost

The civil maintenance costs for each option considered is based on the ground maintenance costs of each solution and includes chipping and periodic weed suppression for outdoor sites. For the Indoor GIS site, provision has been made to paint the external cladding of the building 25 years after it construction.

Annual Reliability cost

The annual reliability cost considers the ongoing costs of unplanned maintenance to plant. For each asset an annual probability of failure for each health index band and mean time to repair (MTTR) in hours is assigned. The annual cost is a function of the MTTR and POF. For the purpose of analysis it is assumed the asset will degrade linearly through each HI band over its life.

Business as Usual Option (Baseline) - AIS inline rebuild

AIS inline rebuild starting in 2015 and completed by 2020. The CBA considers the construction costs, outage risk and ongoing civil and electrical maintainance of the site.

- Costs based on average cost per bay for Kirkby Grid inline AIS Scheme
- Assume 8% uplift on scheme costs due to controlled dismantling of existing structured in live compound
- Assume 0.068 chance of bus zone trip due to protection commisioning resulting in 125,000 customers off supply for 180 minutes
- Assume 0.039 chance of bus zone trip due to inadvertant contact or damage of electrical plant / systems during construction resulting in 125,000 customers off supply for 180 minutes

Option 1 - GIS offline rebuild – **Chosen Option**

GIS offline rebuild starting in 2019 and completed by 2020. The CBA considers the construction costs, outage risk and ongoing civil and electrical maintainance of the site.

- Costs based on detailed scheme design.
- Assume 0.015 chance of bus zone trip due to protection commisioning resulting in 125,000 customers off supply for 180 minutes
- Assume 0.005 chance of bus zone trip due to inadvertant contact or damage of electrical plant / systems during construction resulting in 125,000 customers off supply for 180 minutes

Lowest risk to network during construction. Reduce ongoing H&S risks associated with AIS sites

Term (years from first out flow)	NPV (£m)
16	£1.05
24	£1.04
32	£1.04
45	£1.06
first year of investment out flow	1

Option 2: - Replace OCB's with GCB

Option 2: - Replace OCB's with GCB

Replace OCB's with GCB, renew multicores and refurbish isolators to give a 10 year life extension start 2015 and complete in 2016. Following this carry out AIS inline rebuild utilising existing GCB's starting in 2025, completed by 2028. The CBA considers the construction costs, outage risk and ongoing civil and electrical maintainance of the site.

- Costs based on average cost per bay for Kirkby Grid inline AIS Scheme.
- Assume 8% uplift on scheme costs due to controlled dismantling of existing structured in live compound.
- Costs for stage one OCB to GCB retrofit includes disconnector and civil refurbishment refurbishment. 25% uplift for prelims and project management.
- Assume 0.045 (stage 1) and 0.039 (stage 2) chance of bus zone trip due to protection commisioning resulting in 125,000 customers off supply for 180 minutes.
- Assume 0.029 (stage 1) and 0.024 (stage 2) chance of bus zone trip due to inadvertant contact or damage of electrical plant / systems during construction resulting in 125,000 customers off supply for 180 minutes.

Term (years from first out flow)	NPV (£m)
16	£1.13
24	£0.78
32	£0.54
45	£0.26
first year of investment out flow	1

Option 3: - AIS off line rebuild

Not availible due to space constraints - option rejected on engineering grounds.

Appendix 1: Cost Benefit Analysis

Options considered / project name	Comment
Baseline	AIS inline rebuild starting in 2015 and completed by 2020. The CBA considers the construction costs, outage risk and ongoing civil and electrical maintainance of the site.
Option 1	GIS offline rebuild starting in 2019 and completed by 2020. The CBA considers the construction costs, outage risk and ongoing civil and electrical maintainance of the site.
Option 2	Replace OCB's with GCB, renew multicores and refurbish isolators to give a 10 year life extension start 2015 and complete in 2016. Following this carry out AIS inline rebuild utilising existing GCB's starting in 2025, completed by 2028. The CBA considers the construction costs, outage risk and ongoing civil and electrical maintainance
Option 3	AIS off line rebuild

List below the short list of those options which have been costed within this CBA workbook

Option no.	Options considered	Decision	Comment	For the chosen option only, provide detail of where CBA expenditure included in this CBA is reported in the BPDT pack. e.g. LV swtichgear BPDT CV3 rows 15 to 22.	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
B	**AIS inline rebuild**	**Rejected**							
1	**GIS offline rebuild**	Adopted	Lowest risk to network during construction. Reduce ongoing H&S risks associated with AIS sites	**BPDT CV3 - Row 92,98,102 & BPDT CV6 - Row 33,34,35**	£1.05	£1.04	£1.04	£1.06	
2	**Replace OCB's with GCB**	Rejected	Least economic option		£1.13	£0.78	£0.54	£0.26	
3	AIS off line rebuild	Rejected	Not availible due to space constraints						

Investment Business Case

CBA No.	55
Scheme/Project Name	Rising and Lateral Mains
Scheme/Project Owner	Gordon MacKenzie
Primary Investment Objective	Customer Safety
Secondary Investment Objective (Engineering)	To replace end of life and under-rated Rising and Lateral Mains Systems located within the customers property.

Option no.	**Options considered**	**Decision**
Baseline	Replace HI5 & HI4 poor condition and under rated Rising & Lateral Mains systems including service position equipment	Adopted
1	Replace HI5 & HI4 poor condition service position equipment (cut-outs) only, allowing cable and distribution equipment to fail.	Rejected
2	As Baseline plus upgrade mains and service cables to future proof against load growth	Rejected

Background & Justification

The current investment strategy for Rising and Lateral Mains System in DPCR5 is the replacement of existing end of life and under rated Systems operating within the customers premises. The risks associated with internal mains are measured in terms of the potential hazard resulting from a failure of the assets, principally the public safety risks due to fire and smoke within high occupancy buildings with constrained points of access and egress.
The main public safety risks associated with this asset type arise from direct contact or fire, and smoke hazards within high occupancy buildings having constrained points of access and egress.
Our asset replacement programme for ED 1 will:

- Maintain equipment safety, integrity and performance.
- Ensure compliance with our legal and license obligations.
- Intervene where possible prior to asset failure.
- Reduce risk of third party direct contact with electrical equipment.
- Install low smoke emitting equipment.
- Support the UK governments smart meter roll out programme.

Approximately 70% of properties in SPD and 60% of properties in SPM have their electricity meter connected to a RLM system.

The guidelines for Rising and Lateral Mains Systems are ;

- Replace, with new, all cabling, containment and distribution equipment, HI 4 & 5 end of life and under rated Legacy Assets, focussing on the highest risk systems installed in Multi-Storey Tower Blocks.
- The Modernisation programme will move in ED1 from Multi Storey Tower blocks to the next most heavily populated property types (Flats).

Approach to the Options Appraisal

- *Baseline Option is a continuation of the existing funded DPCR5 modernisation programmewhich was subject to re-opener approval in 2012.*
- *The period for the CBA should be a maximum of 50 years which represents the useful economic life of the asset.*

We have used the following information to calculate our final values which we have used to populate our CBA tables:

9. Condition based volume. 2x Asset surveys completed prior to and during DPCR5 funding allowance approval.
10. Unit Cost. Utilising 3 years modernisation figures and RRP submissions.
11. Replacement profile over ED1 – continuation at DPCR5 outputs and volumes.
12. 3 Years fault profile – Service position incidents SPD
13. 2 Years fault profile – Service position incidents SPM
14. Wider industry profiling of cut out failures resulting in fires.
15. Network Load profiling – increase in Netwrok loading.

Business as Usual Option (Baseline)
Our Business as usual option (Baseline) is to continue our successful DPCR5 Modernisation programme into ED1.

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*

Buildings of multiple occupancy and some adjoining property types contain an internal distribution system referred to as a Rising and Lateral Mains System. Property types include high-rise (Towers) tenemental (flats) and semi-detached (houses). In DPCR5 SPEN took an industry leading approach to the management of the unacceptable public safety risk associated with these ageing systems.

Over the first two years of DPCR5 we have undertaken a significant RLM investment programme both in SPD and SPM, and we have broadly delivered our outputs in line with our DPCR5 allowance. Our funding requirements for the remaining three years DPCR5 are set out below:

	Actuals		Forecast			
	2010/11	2011/12	2012/13	2013/14	2014/15	2012/13 – 2014/15
Expenditure £m* – SPD	8.8	8.4	9.4	9.7	9.7	28.8
Cable installed km – SPD	228	360	245	330	330	905
Expenditure £m* – SPM	0.7	6.0	5.0	4.6	5.3	14.9
Cable installed km – SPM	50	134	153	215	145	423

*2011/12 Real Prices

We have actively engaged with relevant stakeholders throughout the first two years of the DPCR5 settlement, including Local Authorities, Industry Forums (SELECT) and the Health and Safety Executive (HSE), receiving considerable support.

Option 1:

Although considered as part of the Cost Benefit analysis, allowing the equipment located within a customers premise to fail was rejected as this posed an unacceptable risk to the customer. Rising and Lateral Mains systems are located in public areas of multi-oocupancy properties and safe access and egress in the event of system failure is likley to be compromised.

Option 2:

Although considered as part of this Cost Benefit Analysis, increase in load is generally re-chargeable to the customer.

The existing design crirteria associated with modernised Rising and Lateral Mains Systems allows an individual service cable and the associated equipment up to 100 amps per customer, this is on the whole more than adequate for most domestic connections, with no requirement at design stage to design with more capacity.

Appendix 1: Cost Benefit Analysis

Attach CBA spreadsheet here =➔

Options considered	Comment
Baseline Scenario	Replace HI5 & HI4 poor condition and under rated Rising & Lateral Mains systems including service position equipment,with a minimum domestic load design criteria. .Ownership and responsibility for Operating amd Maintaining RLM Systems has been subject to wider industry discussion. SPEN have taken an Industry leading approach to responsibility and customer safety by estblishing a Condition Based and risk mitigating approach to the modernisation of RLM systems, with the customer and stakeholders best served by this approach.
Option 1	Replace HI5 & HI4 poor condition service position equipment (cut-outs) only, Rising Mains and service cables will be repaired on failure. Although there is a financial advantage to allowing the Rising and Lateral Mains systems to fail, there is an ESQCR duty in regards to equipment located on a customers premises which aligns with customer and wider industry expectation that equipment inside their homes will be fit for purpose and in good operating condition.
Option 2	Replace HI5 & HI4 poor condition and under rated Rising & Lateral Mains systems and service position equipment and upgrade mains & service cables to future proof the services against increases in load due to heat pumps etc.
Option 3	Transfer responsibility for RLM systems to building owners. DNO is best placed to ensure Building Netwroks are Operated in compliance with ESQCR. Customer safety is best served by DNO Responsibility. **This approach has been rejected and not carried forward.**
Option 4	Repair failing component parts only. This requires the component parts of the RLM system, Cables, Distribution Equipment, Containment and Service Termination equipment, to be considered separately. This principally would require a fully reactive approach and by design allows equipment located in a customers property to fail before intervention is considered. **This option has been rejected on safety grounds and not carried forward.**

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
	Replace HI5 & HI4 poor condition and under rated Rising & Lateral Mains systems including service position equipment	Adopted	Although there is a financial advantage to allowing the Rising and Lateral Mains systems to fail, there is an ESQCR duty in regards to equipment located on a customers premises which aligns with customer and wider industry expectation that equipment inside their homes will be fit for purpose and in good operating condition.	Allowance in DPCR 5, continued into ED1					
1	Replace HI5 & HI4 poor condition service position equipment (cut-outs) only	Rejected	Service position equipment accounts for a small percentage of the overall Rising & Lateral Mains asset. Although there is significant Smart Meter Roll out focus on the termination equipment, the age profile and condition of the supply cables are such that intervention to remove end of life cables is essential to the success of the Roll out.		-£12.49	-£19.81	-£27.80	£0.00	
2	As Baseline plus upgrade mains and service cables to future proof against load growth		Replace HI5 & HI4 poor condition and under rated Rising & Lateral Mains systems and service position equipment and upgrade mains & service cables to future proof the services against increases in load due to heat pumps etc.		-£74.17	-£94.90	-£108.73	-£122.92	

Investment Business Case

56	56
Scheme/Project Name	RTS Central Systems
Scheme/Project Owner	REDACTED due to commercial sensitivity
Primary Investment Objective	REDACTED due to commercial sensitivity
Secondary Investment Objective (Engineering)	REDACTED due to commercial sensitivity

Investment Business Case

CBA No.	57
Scheme/Project Name	Replacement of end of life RTUs and Development of associated Telecoms Networks
Scheme/Project Owner	Patrick Dolan
Primary Investment Objective	Replacement end of life RTUs to ensure continued operation of the SCADA system in place maintain current levels of network performance, customer service and efficient system management
Secondary Investment Objective (Engineering)	Sustainable control with functionality required for future network requirements

Option no.	Options considered	Decision
(Baseline)	Programme based on installation of an RTU solution, bespokely engineered to support Legacy Protocols and Data Models	Rejected
1	Programme based on installation of an RTU solution, based on industry standard protocol support and support for international standards for substation automation	Rejected
2	Programme based on installation of an RTU solution, based on industry standard protocol support and international standards for substation automation - Extended timescales for population replacement	Adopted
2.1	Sensitivity modelling potential CML impact of programme deferral	
2.2	Sensitivity modelling 30% uplift in equipment replacement costs	

Costs in investment Tables;

- CV105 Operational IT and Telecoms
  - Substation RTUs, marshalling kiosks, receivers
  - Communications for Switching and Monitoring

Breakdown of associated items shown in workings of chosen option 2

Background & Justification

The main drivers for the replacement of legacy RTUs are obsolescence and issues associated with support. These RTUs communicate using bespoke protocols, are limited in their capacity to monitor and control additional plant and unable to fully integrate modern IEDs as associated substation devices.

As these assets cannot be supported in the long term, a replacement programme has been scheduled to commence early in the ED1 period.

There are two main options for the replacement of these legacy RTUs;

- Replace with New bespoke engineered RTU's to integrate into current control system.
- Replace with New RTUs which support industry standard protocols and standards for substation automation and evolve control system accordingly.
- There are also options to adjust the phasing of the replacement activity in a risk weighted manner.

Bespoke engineered RTUs based on current experience are more expensive to purchase than industry standard equipment. Perpetuation of legacy protocols has many long term risks due to associated limited range of RTU supplier's and even more limited range of products on which the legacy protocols can still be supported. As a result, we expect support to be an issue in the future and have assumed that the supportable asset life of these products is less than industry standard products.

Moving to a RTU which utilises modern standard protocols and supports industry standards for substation automation opens up many benefits and opportunities. This also necessitates investment in the telecoms network infrastructure and architecture to cope with associated increases in bandwidth requirements to make the transision.

This CBA was carried out to benchmark costs of moving to a control system where installed RTUs communicate using industry standard protocols in comparison to procuring and installing modern RTUs which have been customised to support legacy protocols and require minimal alteration to the telecoms network.

The CBA considers procuring and installing RTUs bespoke engineered to support legacy protocols as the basecase. This is currently our approach where we have installed RTUs in recent years. The installation of new RTUs (with support for modern industry standards and protocols) has been added as two separate scenarios, a focused investment programme in ED1 and an extended investment programme where recovered RTUs are used to support legacy RTUs in service until they are replaced. An extended programme has not been considered for the bespoke engineered RTU solution as we have assumed that they will become more difficult to support and associated risk is higher when large population of aged legacy RTUs are also being supported.

The outcome of the CBA is not the only consideration for choosing the optimal strategy for this programme. Without the move to modern industry standard equipment we will be unable to share the benefits of innovation in this market, including the development of more advanced network control systems capable of active network management and other smart grid initiatives.

Business as Usual Option (Baseline)

Programme to replace the current legacy RTU's with a New RTU solution bespoke engineered to support legacy protocols within ED1.

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*

Programme to Install RTUs capable of supporting Industry Protocols and Standards for Substation Automation & Invest in required Telecoms Development over an extended period

Approach to the Options Appraisal

- *Baseline is always a 'do minimum'/ Business as usual Option. All the costs and benefits associated with the other options are relative to the do minimum Option (Baseline).*
- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset. – The RTU product has a relatively short asset life in comparison to other network assets. We have, however, modelled the NPV over a longer term due to differences in the assumed asset life of a bespoke engineered RTU and due to the timescales associated with the extended programme option modelled.*

Baseline

- Assumed that bespoke MK3 / DSP4 Compact and Modular RTUs will have an asset life of 12 years as it will be more difficult to support than an industry standard RTU
- Assumed that telecoms equipment associated with current generation RTU modernisation is required when modern equivalent RTU is installed
- Assumed that telecoms equipment has a 15 year life
- Battery and Charger Costs have been assumed as zero cost in this scenario. Other Scenarios include a delta cost (how much more it will cost for a larger battery system than required for this programme).
- Telecoms Service Requirement Changes Investment that are required independent of the RTU installation strategy choice is made has been considered as a null cost item as they are common to all the options explored
- RTUs replaced as part of other capital works are not included in this CBA

Option 1

Programme to Install RTU capable of supporting Industry Protocols and Standards for Substation Automation & Invest in required Telecoms Development within ED1

- Assumed that industry standard Compact and Modular RTUs will have an asset life of 15 years as it is be much more easily supported than an bespoke RTU
- Assumed that all telecoms equipment has a 15 year life
- Full Battery and Charger Installation Uplift delta Costs added for additional capacity requirements has been assumed (Chargers replaced on 30 years)
- Delta Uplift Cost for battery changes replacement cost assumed per set, replacement cycle 8 years
- Telecoms Service Requirement Changes Investment that are required independent of the RTU installation strategy choice is made has been considered as a null cost item as they are common to all the options explored
- RTUs replaced as part of other capital works are not included in this CBA

Term (years from first out flow)	NPV (£m)
16	-£1.29
24	-£1.39
32	£2.31
45	£5.51
first year of investment out flow	1

Option 2

Programme to Install RTU capable of supporting Industry Protocols and Standards for Substation Automation & Invest in required Telecoms Development over an extended period

Assumptions:

- Assumed that industry standard Compact and Modular RTUs will have an asset life of 15 years as it is be much more easily supported than a bespoke RTU
- Assumed that all telecoms equipment has a 15 year life
- Full Battery and Charger Installation Uplift delta Cost is added for additional capacity requirements has been assumed (Chargers replaced on 30 years)
- Delta Uplift Cost for battery changes replacement cost assumed per set, replacement cycle 8 years.
- Telecoms Service Requirement Changes Investment that are required independent of the RTU installation strategy choice is made has been considered as a null cost item as they are common to all the options explored
- RTUs replaced as part of other capital works are not included in this CBA

Term (years from first out flow)	NPV (£m)
16	£5.35
24	£8.96
32	£14.37
45	£20.72
first year of investment out flow	1

Option 2.1

Sensitivity included to explore the potential CML impact of deferring the RTU replacement. If bathtup failure mode occurs at a rate where the deferred RTU population becames impossible to repair/replace in a timely manner then availability of SCADA at associated sites will be impacted.

Associated impact will be much extended fault restoration times where SCADA is unavailavble. Impact is modelled on Annual fault statistics.

Term (years from first out flow)	NPV (£m)
16	£4.37
24	£7.68
32	£13.34
45	£19.43
first year of investment out flow	1

Option 2.3

Sensitivity included to model impact of a 30% uplift in equipment replacement costs for the period considered.

Term (years from first out flow)	NPV (£m)
16	-£1.52
24	-£1.42
32	£1.72
45	£3.84
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Options considered	**Comment**
New RTU solution Bespokely Engineered to support Legacy Protocols and Data Models	Baseline Case
New RTU solution based on industry standard RTU protocols support and Substation Automation Standards	Costed as Option 1
New RTU solution based on industry standard RTU protocols support and Substation Automation Standards - Extended timescales for IEC RTU population replacement (recovered RTUS used as spares	Costed as Option 2
Support current generation of RTUs long term	Dismissed as not possible - Not possible as assets over time will degrade beyond economical repair.
Remove SCADA system	Dismissed as RTUs too essential to network performance to allow to fail

List below the short list of those options which have been costed within this CBA workbook

Option no.	**Options considered**	**Decision**	**Comment**	**Spend area (from Table C1) (relevant only to adopted option)**	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	New RTU solution based on industry standard RTU protocols support and Substation Automation Standards		Least economic option		-£1.29	-£1.39	£2.31	£5.51	
2	New RTU solution based on industry standard RTU protocols support and Substation Automation Standards - Extended timescales for IEC RTU population replacement (recovered RTUS used as spares	Adopted	Most economic option		£5.35	£8.96	£14.37	£20.72	
2.1	Sensitivity of CML Performance impact of investment deferal		Move to industry standard protocols and subsequent development to telecoms network, sets a good foundation for Smart Grid initiatives to be built upon. Extended implementation timescales defer capital and allow time for strategy and programme implementation to mature and optimise - Sensitivity with CML impact		£4.37	£7.68	£13.34	£19.43	
2.2	Sensitivity of equipment replacment costs increase by 30% and CML Performance impact of investment deferal		Move to industry standard protocols and subsequent development to telecoms network, sets a good foundation for Smart Grid initiatives to be built upon. Extended implementation timescales defer capital and allow time for strategy and programme implementation to mature and optimise - Sensitivity of equipment replacement cost increases (30%) and CML impacty		-£1.52	-£1.42	£1.72	£3.84	

Investment Business Case

CBA No.	58
Scheme/Project Name	11kV RMU
Scheme/Project Owner	David Neilson
Primary Investment Objective	Replace end of life HI 5 assets to improve performance, saftey and reduce risk.
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	Replace HV RMU as per the plan	Rejected
Option 1	Refurbish and replace RMU	Adopted

Background & Justification

We plan to manage our fleet of ring main units (RMU) over the next 2 price reviews, replacing when required, and extending the life of others. Our ED 1 strategy is to replace end of life assets. However due to the high volume of RMU assets we plan to replace, and refurbish these assets. This CBA demonstates refurbishment as a viable option. The vast proportion of RMU are outdoor. There units are subject to weathering and possible water ingress. Although these units have been resilient, they have beeen on the network for some time, and require further interventions in addition to maintenance. We plan a deep scope refurbishment programme in addition to our replacement and maintenance programmes. Further to this we will target erecting a housing over units where the environment has proven problematic.

Business as Usual Option (Baseline/Option 1)

Our Business as usual option (Baseline/Option 1) is Replace HV 11kV RMU in line with our current plan volume.

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*

Refurbish and replace based full plan volume

Option 1:

On top of baseline target high loss units (pre 1962) out with RMU programme based on load.

Term (years from first out flow)	NPV (£m)
16	**£5.72**
24	**£5.37**
32	**£4.99**
45	**£4.51**
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Attach CBA spreadsheet here =➔

Options considered	Comment
Baseline scenario	Replace HV 11kV RMU in line with our current planvolume
Option 1	Refurbish and replace based full plan volume
Option 2	Replace upon failure rejected due to safety risk.

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	Replace HV RMU as per the plan	Rejected	The replacement of the total volume is greater than the refurb / replacement mix						
1	Refurbish and replace RMU	Adopted	Accepted as an optimised plan		£5.72	£5.37	£4.99	£4.51	

Investment Business Case

CBA No.	59
Scheme/Project Name	33kV CB Outdoor
Scheme/Project Owner	David Neilson
Primary Investment Objective	Replace end of life HI 5 assets to improve performance, saftey and reduce risk.
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	Replace EHV 33kV Circuit breakers in line with our current plan	Adopted
I	Replace based refurbishment	Rejected

Background & Justification

Replace end of life HI 5 assets to improve performance, saftey and reduce risk. Our ED 1 strategy is to replace end of life outdoor circuit breakers and the associated disconnectors which are deteriorating, poorly performing and costly to maintain, with ID high performance low maintenance assets. Our current circuit breaker and the supporting structures are degrading. The operability of the breaker, structure condition and air break disconnectors performance are not fit for purpose. Further to this the security costs of maintaining a large substation compound and the risk to the public and staff drive us to deliver an indoor solution. Further to this the lifetime, operability and performance benefits outway any outdoor solution. Our existing oil citcuit breakers and air break switches require routine and post fault maintenance every 6 years. The cost is highcompare to gas circuir breaker, whichare tested more frequently, but at much lower cost. In addition they do not have outdoor disconnectors.

Business as Usual Option (Baseline/Option 1)

Our Business as usual option (Baseline/Option 1) is Replace EHV 33kV Circuit breakers in line with our current plan

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*

Baseline Option

Option 1:

On top of baseline target high loss units (pre 1962) out with RMU programme based on load.

Term (years from first out flow)	NPV (£m)
16	-£0.53
24	-£6.19
32	-£9.65
45	-£13.47
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Attach CBA spreadsheet here =➔

Options considered	Comment
Baseline scenario	Replace EHV 33kV Circuit breakers in line with our current plan
Option 1	Refurbish rather than replace with a 10 year life extension
Option 2	Replace upon failure - rejected on saftey grounds
Option 3	Replace and refurbish in a mixed plan - rejected on economic grounds

List below the short list of those options which have been costed within this CBA workbook

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	Replace EHV 33kV Circuit breakers in line with our current plan	Adopted	Most economic option						
1	Replace based refurbishment	Rejected	Rejected due to negative NPV		-£0.53	-£6.19	-£9.65	-£13.47	

Investment Business Case

CBA No.	60
Scheme/Project Name	33kV RMU
Scheme/Project Owner	David Neilson
Primary Investment Objective	Replace end of life HI 5 assets to improve performance, saftey and reduce risk.
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	Replace EHV 33kV RMU in line with our current plan	Adopted
1	Replace based refurbishment	Rejected

Background & Justification

Replace end of life HI 5 assets to improve performance, saftey and reduce risk. Our ED 1 strategy is to replace end of life assets ID 33kV RMU deteriorating poorly performing and costly assets with high performance circuit breaker assets. Our current RMU assets are degrading. The operability of th circiut breaker and switches are not fit for purpose. In particular the switches have operational restrictions. Our plan is to remove these assets and replace with 3 circuit breaker new technology sf6 type assets.

Business as Usual Option (Baseline/Option 1)

Our Business as usual option (Baseline/Option 1) is Replace HV 33kV RMU in line with our current plan volume.

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*

Refurbish and replace based full plan volume

Option 1:

On top of baseline target high loss units (pre 1962) out with RMU programme based on load.

Term (years from first out flow)	NPV (£m)
16	£1.11
24	£0.28
32	-£0.30
45	-£0.97
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Attach CBA spreadsheet here =➔

Options considered	Comment
Baseline scenario	Replace HV 11kV RMU in line with our current planvolume
Option 1	Refurbish and replace based full plan volume
Option 2	Replace upon failure rejected due to safety risk.

List below the short list of those options which have been costed within this CBA workbook

Option	Options considered	Decision	Comment	Spend area (from Table C1)	sed on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	Replace EHV 33kV Circuit breakers in li	Adopted							
1	Replace based refurbishment	Rejected	Rejected on the basis that this is not the most economic option over the lifetime of the equipment		£1.11	£0.28	-£0.30	-£0.97	

Investment Business Case

CBA No.	61
Scheme/Project Name	33kV OHL Storm Resilience
Scheme/Project Owner	
Primary Investment Objective	To achieve a storm resilient 33kV overhead line network.
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
Baseline	Baseline scenario: Rebuild overhead line to new storm resilient specification and cut trees to ETR132 methodology	Adopted
1	Rebuild overhead line to new specification but do not cut trees to ETR132	Rejected
2	Refurbish the overhead line only	Rejected
3	Underground the overhead line	Rejected

Background & Justification

The EHV (33kV) wod pole overhead line network is a strategic asset, connecting our grid and primary substations in rural areas. In the vast majority of cases these are interconnected or have additional feeders to primary substations, which provides redundancy and a higher security of supply. Due to this, EHV lines were historically constructed to more onerous standards than at lower Voltages.

Following the effects of severe storms in the late 1990s and early 2000s, we initiated industry leading programmes to clear trees from our overhead line networks and modernise the overhead line network. From our experience, we consider ‘storm resilience’ to cover two key areas: capability to withstand wind loading and ice accretion on conductors/poles, and cutting of trees within falling distance as per industry standard methodology ETR132.

We have assessed the prevailing conditions across our network through MET office-developed maps and developed a new suite of OHL installation specifications which are deemed to be ‘Fit for Purpose’ for these areas. An independent storm review undertaken by KEMA[2], assessing empirical overhead line network performance, confirmed a ‘10 fold’ reduction in fault rate during storms on circuits which have been engineered to be storm resilient. This was borne out in January 2012, when the network withstood the storm and had 76% fewer faults than was suffered when an identical storm hit the network in December 1998.

Our continuing strategy from DPCR5 is to rebuild 33V lines to a resilient, ‘fit for purpose’ specification based on an assessment of condition, specification and weather area. Our long term objective is that by 2034 40% of interconnected 33kV main lines will be rebuilt to a storm resilient standard with ETR132 tree cutting, such that a severe weather event should not affect any connected customer for more than 36 hours. This policy was recognized as industry leading by PB Power.

To achieve this, we will:

- Rebuild 2% of the 33kV network annually;
    - Rebuild 1% to an upgraded, fit for purpose specification taking into account the land topography and prevailing severe and normal weather patterns and cut trees to ETR132.
    - Where the existing 33kV specification is suitable for the weather area, we will rebuild the line 1% of our network in-situ and cut trees to ETR132

In tandem with this programme, in ED1 we will also continue our DPCR5 strategy of a rolling 12-year refurbishment cycle, which covers our entire 33kV overhead pole line asset base. This will maintain network performance and mange our aging assets through ED1. To achieve this we will:

- Refurbish 6% of the 33kV network annually to improve network condition and performance.

Approach to the Options Appraisal

- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

[2] KEMA Report G07-1652 February 2007, Iain Wallace: An Assessment of HV Overhead Storm Resilience.

<u>Assumptions</u>

- The cost of completely rebuilding a 33kV overhead main line to a storm resilient specification is £51k per km. This is the option selected for the CBA, where all conductor and poles are replaced.
- make the numbers meaningful, 100 km has been considered rather than just 1 km.
- All rebuilt lines will have tree cut in accordance with ENA ETR 132.
- The average cost for a circuit to achieve ETR 132 compliance is £9K per km.
- Follow up tree cutting to maintain ETR 132 compliance shall take place every 3 years.
- The kilometre rate for tree cuttings inclusive of carrying out surveying and obtaining permissions, (inclusive of staff Authorised to receive a Permit for Work and to erect overhead line earths, where required) is £657.14.
- The line will be refurbished every 12 years.
- The expected lifespan of a creosoted wood pole is approx 63 years ± 13 years.
- The baseline view of the circuit is that the condition/specification is such that it is a candidate for rebuild, with average wood pole of approx. 40 years.
- Base refurbishment costs are £5k per km.
- For newly built lines, the refurb cost will be proportionally lower immediately following rebuild. This will increase to the nominal refurb cost of £5k over three periods of refurbishment.
- Due to wood pole and conductor degradation over the 45 year life span, it is assumed that these will need incremental replacement over this lifespan (above that considered within refurbishment base cost). As specific rates of degradation/failure cannot be determined, an average is assumed.
- Baseline fault rates have been taken from NAFIRS tables.
- When an overhead line is storm resilient rebuilt, including to ETR 132, it is assumed that there will be a 90% reduction in certain types of faults (e.g. wear and tear and wind borne material) but no reduction in other faults (e.g. third party damage or lightning). Overall there will be a 65.39% reduction in faults.
- When an overhead line is refurbished, less fault producing categories are affected and there will be only an 80% reduction in those. Overall, there will be a 39.26%.
- It is assumed that on lines that are not rebuilt to a storm resilient standard, there will be a resultant increase in faults and associated costs annually as a result of severe weather impacts. Several of these events are typically experienced every year in both licence areas, however, the type (wind/ice/snow), extent and timing of these cannot be forecast. Therfore an average has been assumed.
- SPD customer information has been used for this CBA; however, although there a slight differences between the SPD and the SPM data, this does not cause any material difference to the analysis.
- The cost benefit analysis is based on the SPD severe weather areas, while the main lines of normal weather areas will also be rebuilt to an appropriate design specification for the environment, this will be a lower cost that the design specification for the severe weather areas and therefore the outcome of the analysis will show a greater benefit in rebuilding the overhead line rather than undergrounding the network.

Business as Usual Option (Baseline)
Rebuild 33kV main lines to a storm resilient specification and cut trees to ETR132 methodology – **Chosen Option**

This is most effectively achieved through a coordinated approach to vegetation management and construction of overhead lines to a standard that is suitable for the weather environment where it is erected. An independent storm review looking at empirical overhead line network performance has shown a '10' fold reduction in fault rate during storms on circuits which have been engineered to be storm resilient. This was borne out in January 2012, when the network withstood the storm and had 76% fewer faults than was suffered when an identical storm hit the network in December 1998. The robust specification will not only withstand storms but will also suffer from less faults than refurbished lines over the first 20 years. Once built to a suitable specification, the line will be refurbished every 12 years and the tree resilience maintained with cutting taking place every 3 years. Note: 100km of main line has been considered for this CBA, with the line considered to be approx 35 years old.

Option 1 –
Rebuild 33kV main lines to a storm resilient construction without ETR 132 tree cutting.

Although achieving ETR 132 tree compliance is an integral component of the storm resilient overhead line construction, this portion could be detatched from the specification. This would result in increased faults due to growing or falling trees and windborne material, resulting in a greater number of faults and longer restoration times particularly during storms. The line would still be considered resilient to ice accretion/wind loading during storm events.

Term (years from first out flow)	NPV (£m)
16	-£0.09
24	-£0.22
32	-£0.49
45	-£0.94
first year of investment out flow	1

Option 2 - Refurbishment of 11kV main line

Refurbishment of 33kV lines forms our strategy for managing performance and component degradation until the circuit is rebuilt. In ED1 we plan to continue our rolling 12 year cycle for refurbishment. The main lines under consideration are to designs that are no longer suitable for the environment in which they are built. In recent years, storms have typically become more frequent and more severe. ENA Technical Specification 43-40 details the ice and wind loadings that can be expected throughout the country taking height into account. Additionally, our refurbishment unit costs are based on the refurbishing lines that are generally fit for purpose. For this CBA, the baseline considers a circuit that is due for rebuild based on condition and a specification that is not 'fit for purpose'. To provide a meaningful comparison, the rebuild scenario would have to cover - at a minimum - the replacement of all 'end of life' poles during this 45 year timescale. This is in addition to the baseline unit cost for refurbishment. Refurbished lines are not considered 'storm resilient' in our plans, and so would be subject to the impacts of wind/ice storms, of which we have had on average 5 p.a. through DPCR5.

Term (years from first out flow)	NPV (£m)
16	£0.04
24	-£0.61
32	-£1.48
45	-£2.85
first year of investment out flow	1

Option 3 - Undergrounding of 11kV main line

Replacement of the 33kV overhead main line with an underground cable. The payback periods under considreation are all less that the estimated time frame of when the cable will start to deteriorate, so there will be no faults associated with this scenario.

Term (years from first out flow)	NPV (£m)
16	-£5.44
24	-£6.29
32	-£6.78
45	-£7.12
first year of investment out flow	1

Sensitivity Analysis

N/A

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Baseline scenario: Rebuild 33kV main lines to a storm resilient specification and cut trees to ETR132 methodology	This is most effectively achieved through a coordinated approach to vegetation management and construction of overhead lines to a standard that is suitable for the weather environment where it is erected. An independent storm review looking at empirical overhead line network performance has shown a '10' fold reduction in fault rate during storms on circuits which have been engineered to be storm resilient. This was borne out in January 2012, when the network withstood the storm and had 76% fewer faults than was suffered when an identical storm hit the network in December 1998. The robust specification will not only withstand storms but will also suffer from less faults than refurbished lines over the first 24 years. Once built to a suitable specification, the line will be refurbished every 12 years and the tree resilience maintained with cutting taking place every 3 years. **Note: 100km of main line has been considered for this CBA.**
Rebuild 33kV main lines to a storm resilient construction without ETR 132 tree cutting.	Although achieving ETR 132 tree compliance is an integral component of the storm resilient overhead line construction, this portion could be detatched from the specification. This would result in increased faults due to growing or falling trees and windborne material, resulting in a greater number of faults and longer restoration times particularly during storms. The line would still be considered resilient to ice accretion/wind loading during storm events.
Refurbishment of 33kV main line	Refurbishment of 33kV lines forms our strategy for managing performance and component degradation until the circuit is rebuilt. In ED1 we plan to continue our rolling 12 year cycle for refurbishment. The main lines under consideration are to designs that are no longer suitable for the environment in which they are built. In recent years, storms have typically become more frequent and more severe. ENA Technical Specification 43-40 details the ice and wind loadings that can be expected throughout the country taking height into account. Additionally, our refurbishment unit costs are based on the refurbishing lines that are generally fit for purpose. For this CBA, the baseline considers a circuit that is due for rebuild based on condition and a specification that is not 'fit for purpose'. To provide a meaningful comparison, the rebuild scenario would have to cover - at a minimum - the replacement of all 'end of life' poles during this 45 year timescale. This is in addition to the baseline unit cost for refurbishment. Refurbished lines are not considered 'storm resilient' in our plans, and so would be subject to the impacts of wind/ice storms, of which we have had on average 5 p.a. through DPCR5.
Undergrounding of 33kV main line	Replacement of the 33kV overhead main line with an underground cable. The payback periods under considreation are all less that the estimated time frame of when the cable will start to deteriorate, so there will be no faults associated with this scenario.

Option no.	Options considered	Decision	Comment	NPVs based on payback periods				
				16 years	24 years	32 years	45 years	DNO view
Baseline	Baseline scenario: Rebuild overhead line to new storm resilient specification and cut trees to ETR132 methodology	Adopted	Most economic option	£0.00	£0.00	£0.00	£0.00	
1	Rebuild overhead line to new specification but do not cut trees to ETR132	Rejected	Rejected due to negative NPV	-£0.09	-£0.22	-£0.49	-£0.94	
2	Refurbish the overhead line only	Rejected	Rejected due to negative NPV	£0.04	-£0.61	-£1.48	-£2.85	
3	Underground the overhead line	Rejected	Rejected due to negative NPV	-£5.44	-£6.29	-£6.78	-£7.12	

Investment Business Case

CBA No.	62
Scheme/Project Name	LV Street Link Assets
Scheme/Project Owner	David Neilson
Primary Investment Objective	Replace end of life HI 5 assets to improve performance, saftey and reduce risk.
Secondary Investment Objective (Engineering)	

Option no.	**Options considered**	**Decision**
Baseline	Replace and refurbishment	Adopted
Option 1	Replace the full programme of LV assets	Rejected

Background & Justification

During RIIO ED 1 we plan to replace 4864 LV street link assets. We plan to replace HI 5 assets with mainly UGLB, and a proportion of LV pillars. These assets are generally located on most streets and provide linking for alternative supplies for faults and maintenance.

Business as Usual Option (Baseline/Option 1)

Our Business as usual option (Baseline/Option 1) is Replacement of pillars and UGLB, including refurbishing UGLB lids

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*

Baseline Option

Option 1:

Replace the full programme of LV assets

Term (years from first out flow)	NPV (£m)
16	-£12.86
24	-£16.42
32	-£18.82
45	-£21.29
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Attach CBA spreadsheet here =➔

Options considered	Comment
Baseline scenario	Replacement of pillars and UGLB, including refurbishing UGLB lids
Option 1	Replace the full programme of LV assets
Option 2	Inspection and maintenance only - rejected based on customer impact and safety

List below the short list of those options which have been costed within this CBA workbook

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline	Replace and refurbishment	Adopted	Most economic option						
1	Replace the full programme of LV assets	Rejected	Rejected due to negative NPV		-£12.86	-£16.42	-£18.82	-£21.29	

Investment Business Case

CBA No.	63
Scheme/Project Name	132kV Transformer Refurbishment - SPM
Scheme/Project Owner	Carlos Vila
Primary Investment Objective	Fleet of 16 132/33kV Transformers (HI4): They are 16 units presenting a very poor external condition, so due to leakages and moisture ingress, it is expected that their deterioration process will accelerate during ED-1 period, meaning than most of them will reach category HI5 during ED-2 if no action is taken. However they present no signs of severe or irreversible internal deterioration (fair DGA analysis) and they are units working at low loads (<30% of capacity) so a proper refurbishment is capable to extend the asset life considerably and improve the units to HI2.
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
1	Baseline- The fleet of transformers continues the natural ageing process and diagnosis will start determining that most of them will need to be replaced	Rejected
2	On-site refurbishments	Adopted
2.1	Sensitivity: 80% higher Refurbishment cost	
2.2	Sensitivity: 2-fold higher I&M cost	
2.3	Sensitivity: 97% higher failure probability in the refurbishment scenario than in the baseline scenario.	

Background & Justification

Most of the electrical infrastructure was developed during the 1960's and 1970's. Transformers are a key component of the network so it is of vital importance to manage properly this ageing fleet to guarantee a reliable supply. Even more important, many transformers are located in urban areas so taking the actions required to avoid a catastrophic failure of any of the units shall be an absolute priority for DNOs. However, due to the high reliability of transformers before ageing deterioration, few investments have been done in the latest 20-30 years. Transformer insulation does not have a definite "life" at the end of which it will suddenly fail. Rather, the risk of failure of the insulation due to stresses caused by system short circuits increases with insulation aging. The transformer should be replaced when the risk becomes unacceptable and this is assessed by different diagnosis techniques which determine when the unit has reached its end of life (HI5). The challenge in the near future will be dealing with a high volume of transformers which will need to be replaced. For transformers with certain characteristics, mid-life refurbishments will delay and spread over time their end of life and therefore the large capital expenditure required for replacing the existing fleet. This analysis determines whether this capex delay offsets the cost of the refurbishment intervention.

Approach to the Options Appraisal

- *Option 1 is always a 'do minimum'/ Business as usual Option. All the costs and benefits associated with the other options are relative to the do minimum Option (Option 1).*
- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline/Option 1)

The fleet of transformers continues the natural ageing process and diagnosis will start determining that most of them will need to be replaced

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*
Option 2

On-site refurbishment.

According to the NPV calculation this option is financially favourable. The resulting HI profile of the fleet at the end of the calculation period is also better than in the baseline. The low sensitivity of the relevant parameters determines that the confidence on this decision is very high.

Term (years from first out flow)	NPV (£m)
16	**£3.50**
24	**£2.75**
32	**£2.28**
45	**£1.70**
first year of investment out flow	1

Sensitivities

Option 2.1: - 80% higher Refurbishment cost

Term (years from first out flow)	NPV (£m)
16	£2.78
24	£1.84
32	£1.24
45	£0.52
first year of investment out flow	1

Option 2.2: - 2-fold higher I&M cost

Term (years from first out flow)	NPV (£m)
16	£3.47
24	£2.71
32	£2.23
45	£1.63
first year of investment out flow	1

Option 2.3: - 97% higher failure probability in the refurbishment scenario than in the baseline scenario

Term (years from first out flow)	NPV (£m)
16	£3.46
24	£2.70
32	£2.23
45	£1.64
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Option 1 Baseline scenario: Current replacement strategy	Keep the routine maintenance & inspections. The fleet of transformers continues the natural ageing process and diagnosis will start determining that most of them will need to be replaced -reach HI5- during the ED-2 period.
Replacements after failure	Continue the operation of the transformer until it fails beyond repair and has to be replaced. This alternative has been considered unacceptable as a catastrophic failure can result in fire or explosion, endangering the surrounding assets and protection systems, the staff and the public in case of urban areas. This risk has to be eliminated by replacing HI5 transformers as soon as reasonably
Early replacements	Replace the fleet as soon as possible to improve the reliability of the system. This alternative is not practicable as there are already transformers in a worse condition (HI5) which will be prioritized for replacement during ED-1 period.
Option 2 On-site refurbishments	Carry out the necessary refurbishment interventions on-site to achieve HI reduction. As the transformers in the considered fleet have a fair internal condition, the external works (tank, gaskets, valves, fins, ...) and oil treatments applied will reduce the deterioration rate and extend their useful life.
Factory refurbishments	Carry out a heavy refurbishment, including rewinding and other works which require de-tanking. This option has not been considered after researching the alternatives with suppliers as normally this works required transport to factory and re-commissioning when completed and their cost was in the range of a replacement.

List below the short list of those options which have been costed within this CBA workbook

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	Baseline- The fleet of transformers continues the natural ageing process and diagnosis will start determining that most of them will need to be replaced	Rejected			£0.00	£0.00	£0.00	£0.00	
2	On-site refurbishments	Adopted	Most economic option	Network Investment Core Costs	£3.50	£2.75	£2.28	£1.70	
2.1	Sensitivity: 80% higher Refurbishment cost		NPV in year 45 does not become negative when the parameter is a 80% higher. Therefore, even a high deviation from the assumption in Option 1 would not change the decision taken.		£2.78	£1.84	£1.24	£0.52	
2.2	Sensitivity: 100% higher I&M cost		NPV in year 45 does not become negative for a 100% increase in the parameter. This is due to the fact that the inspections & maintenance activities do not represent a high cost compared to other parameters.		£3.47	£2.71	£2.23	£1.63	
2.3	Sensitivity: 97% higher failure probability in the refurbishment scenario than in the baseline scenario.		NPV in year 45 does not become negative when the parameter is a 97% higher than in the baseline scenario. Therefore, even a high deviation from the assumption in Option 1 would not change the decision taken.		£3.46	£2.70	£2.23	£1.64	

Investment Business Case

CBA No.	64.1
Scheme/Project Name	33kV Transformer Refurbishment - SPD
Scheme/Project Owner	Carlos Vila
Primary Investment Objective	Fleet of 33/11kV Transformers (HI4): There is a significant number of units presenting a very poor external condition, so due to leakages and moisture ingress, it is expected that their deterioration process will accelerate during ED-1 period, meaning than most of them will reach category HI5 during ED-2 if no action is taken. However they present no signs of severe or irreversible internal deterioration (fair DGA analysis) and they are units working at low loads (<30% of capacity) so a proper refurbishment is capable to extend the asset life considerably and improve the units to HI2.
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
1	Baseline- The fleet of transformers continues the natural ageing process and diagnosis will start determining that most of them will need to be replaced	Rejected
2	On-site refurbishments	Adopted
2.1	Sensitivity: 80% higher Refurbishment cost	
2.2	Sensitivity: 2-fold higher I&M cost	
2.3	Sensitivity: 97% higher failure probability in the refurbishment scenario than in the baseline scenario.	

Background & Justification

Most of the electrical infrastructure was developed during the 1960's and 1970's. Transformers are a key component of the network so it is of vital importance to manage properly this ageing fleet to guarantee a reliable supply. Even more important, many transformers are located in urban areas so taking the actions required to avoid a catastrophic failure of any of the units shall be an absolute priority for DNOs. However, due to the high reliability of transformers before ageing deterioration, few investments have been done in the latest 20-30 years. Transformer insulation does not have a definite "life" at the end of which it will suddenly fail. Rather, the risk of failure of the insulation due to stresses caused by system short circuits increases with insulation aging. The transformer should be replaced when the risk becomes unacceptable and this is assessed by different diagnosis techniques which determine when the unit has reached its end of life (HI5). The challenge in the near future will be dealing with a high volume of transformers which will need to be replaced. For transformers with certain characteristics, mid-life refurbishments will delay and spread over time their end of life and therefore the large capital expenditure required for replacing the existing fleet. This analysis determines whether this capex delay offsets the cost of the refurbishment intervention.

Approach to the Options Appraisal

- *Option 1 is always a 'do minimum'/ Business as usual Option. All the costs and benefits associated with the other options are relative to the do minimum Option (Option 1).*
- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

Business as Usual Option (Baseline/Option 1)

The fleet of transformers continues the natural ageing process and diagnosis will start determining that most of them will need to be replaced

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*
Option 2

On-site refurbishment.

Carry out the necessary refurbishment interventions on-site to achieve HI reduction. As the transformers in the considered fleet have a fair internal condition, the external works (tank, gaskets, valves, fins, ...) and oil treatments applied will reduce the deterioration rate and extend their useful life.

Term (years from first out flow)	NPV (£m)
16	£3.11
24	£4.38
32	£4.56
45	£3.81
first year of investment out flow	1

According to the NPV calculation this option is financially favourable. The resulting HI profile of the fleet at the end of the calculation period is also better than in the baseline. The low sensitivity of the relevant parameters determines that the confidence on this decision is very high.

Sensitivities

Option 2.1: - 80% higher Refurbishment cost

Term (years from first out flow)	NPV (£m)
16	£1.45
24	£2.24
32	£2.10
45	£1.03
first year of investment out flow	1

Option 2.2: - 2-fold higher I&M cost

Term (years from first out flow)	NPV (£m)
16	£3.02
24	£4.21
32	£4.31
45	£3.44
first year of investment out flow	1

Option 2.3: - 97% higher failure probability in the refurbishment scenario than in the baseline scenario

Term (years from first out flow)	NPV (£m)
16	£1.62
24	£2.73
32	£2.85
45	£2.04
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

List below all options considered to meet the stated aim

Options considered	Comment
Option 1 Baseline scenario: Current replacement strategy	Keep the routine maintenance & inspections. The fleet of transformers continues the natural ageing process and diagnosis will start determining that most of them will need to be replaced -reach HI5- during the ED-2 period.
Replacements after failure	Continue the operation of the transformer until it fails beyond repair and has to be replaced. This alternative has been considered unacceptable as a catastrophic failure can result in fire or explosion, endangering the surrounding assets and protection systems, the staff and the public in case of urban areas. This risk has to be eliminated by replacing HI5 transformers as soon as reasonably
Early replacements	Replace the fleet as soon as possible to improve the reliability of the system. This alternative is not practicable as there are already transformers in a worse condition (HI5) which will be prioritized for replacement during ED-1 period.
Option 2 On-site refurbishments	Carry out the necessary refurbishment interventions on-site to achieve HI reduction. As the transformers in the considered fleet have a fair internal condition, the external works (tank, gaskets, valves, fins, ...) and oil treatments applied will reduce the deterioration rate and extend their useful life.
Factory refurbishments	Carry out a heavy refurbishment, including rewinding and other works which require de-tanking. This option has not been considered after researching the alternatives with suppliers as normally this works required transport to factory and re-commissioning when completed and their cost was in the range of a replacement.

List below the short list of those options which have been costed within this CBA workbook

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	Baseline- The fleet of transformers continues the natural ageing process and diagnosis will start determining that most of them will need to be replaced	Rejected			£0.00	£0.00	£0.00	£0.00	
2	On-site refurbishments	Adopted	Most economic option		£3.11	£4.38	£4.56	£3.81	
2.1	Sensitivity: 80% higher Refurbishment cost		NPV in year 45 becomes £1.08m when the parameter is a 80% higher. Therefore, even a high deviation from the assumption in Option 1 would not change the decision taken.		£1.45	£2.24	£2.10	£1.03	
2.2	Sensitivity: 2-fold higher I&M cost		NPV in year 45 only varies a 10% for a 100% increase in the parameter. This is due to the fact that the inspections & maintenance activities do not represent a high cost compared to other parameters.		£3.02	£4.21	£4.31	£3.44	
2.3	Sensitivity: 97% higher failure probability in the refurbishment scenario than in the baseline scenario.		NPV in year 45 almost halves when the parameter is a 97% higher than in the baseline scenario. Therefore, even a high deviation from the assumption in Option 1 would not change the decision taken.		£1.62	£2.73	£2.85	£2.04	

Investment Business Case

CBA No.	64.2
Scheme/Project Name	33kV Transformer Refurbishment - SPM
Scheme/Project Owner	Carlos Vila
Primary Investment Objective	Fleet of 33/11kV Transformers (HI4): There is a significant number of units presenting a very poor external condition, so due to leakages and moisture ingress, it is expected that their deterioration process will accelerate during ED-1 period, meaning than most of them will reach category HI5 during ED-2 if no action is taken. However they present no signs of severe or irreversible internal deterioration (fair DGA analysis) and they are units working at low loads (<30% of capacity) so a proper refurbishment is capable to extend the asset life considerably and improve the units to HI2.
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
1	Baseline- The fleet of transformers continues the natural ageing process and diagnosis will start determining that most of them will need to be replaced	Rejected
2	On-site refurbishments	Adopted
2.1	Sensitivity: 80% higher Refurbishment cost	
2.2	Sensitivity: 2-fold higher I&M cost	
2.3	Sensitivity: 97% higher failure probability in the refurbishment scenario than in the baseline scenario.	

Background & Justification

Most of the electrical infrastructure was developed during the 1960‘s and 1970‘s. Transformers are a key component of the network so it is of vital importance to manage properly this ageing fleet to guarantee a reliable supply. Even more important, many transformers are located in urban areas so taking the actions required to avoid a catastrophic failure of any of the units shall be an absolute priority for DNOs. However, due to the high reliability of transformers before ageing deterioration, few investments have been done in the latest 20-30 years. Transformer insulation does not have a definite "life" at the end of which it will suddenly fail. Rather, the risk of failure of the insulation due to stresses caused by system short circuits increases with insulation aging. The transformer should be replaced when the risk becomes unacceptable and this is assessed by different diagnosis techniques which determine when the unit has reached its end of life (HI5). The challenge in the near future will be dealing with a high volume of transformers which will need to be replaced. For transformers with certain characteristics, mid-life refurbishments will delay and spread over time their end of life and therefore the large capital expenditure required for replacing the existing fleet. This analysis determines whether this capex delay offsets the cost of the refurbishment intervention.

Approach to the Options Appraisal

- *Option 1 is always a 'do minimum'/ Business as usual Option. All the costs and benefits associated with the other options are relative to the do minimum Option (Option 1).*
- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

<u>**Business as Usual Option (Baseline/Option 1)**</u>

Keep the routine maintenance & inspections. The fleet of transformers continues the natural ageing process and diagnosis will start determining that most of them will need to be replaced -reach HI5- during the ED-2 period.

<u>**Chosen Option** *(Includes engineering justification if not choosing the highest NPV)*</u>
<u>Option 2</u>

On-site refurbishment.

Continue the operation of the transformer until it fails beyond repair and has to be replaced. This alternative has been considered unacceptable as a catastrophic failure can result in fire or explosion, endangering the surrounding assets and protection systems, the staff and the public in case of urban areas. This risk has to be eliminated by replacing HI5 transformers as soon as reasonably practicable.

Term (years from first out flow)	NPV (£m)
16	£1.46
24	£2.39
32	£2.12
45	£1.53
first year of investment out flow	1

According to the NPV calculation this option is financially favourable. The resulting HI profile of the fleet at the end of the calculation period is also better than in the baseline. The low sensitivity of the relevant parameters determines that the confidence on this decision is very high.

Sensitivities

Option 2.1: - 80% higher Refurbishment cost

Term (years from first out flow)	NPV (£m)
16	£0.35
24	£0.48
32	-£0.20
45	-£0.98
first year of investment out flow	1

Option 2.2: - 2-fold higher I&M cost

Term (years from first out flow)	NPV (£m)
16	£1.03
24	£1.29
32	£0.69
45	-£0.06
first year of investment out flow	1

Option 2.3: - 97% higher failure probability in the refurbishment scenario than in the baseline scenario

Term (years from first out flow)	NPV (£m)
16	£0.59
24	£0.87
32	£0.32
45	-£0.33
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

List below all options considered to meet the stated aim

Options considered	**Comment**
Option 1 Baseline scenario: Current replacement strategy	Keep the routine maintenance & inspections. The fleet of transformers continues the natural ageing process and diagnosis will start determining that most of them will need to be replaced -reach HI5- during the ED-2 period.
Replacements after failure	Continue the operation of the transformer until it fails beyond repair and has to be replaced. This alternative has been considered unacceptable as a catastrophic failure can result in fire or explosion, endangering the surrounding assets and protection systems, the staff and the public in case of urban areas. This risk has to be eliminated by replacing HI5 transformers as soon as reasonably
Early replacements	Replace the fleet as soon as possible to improve the reliability of the system. This alternative is not practicable as there are already transformers in a worse condition (HI5) which will be prioritized for replacement during ED-1 period.
Option 2 On-site refurbishments	Carry out the necessary refurbishment interventions on-site to achieve HI reduction. As the transformers in the considered fleet have a fair internal condition, the external works (tank, gaskets, valves, fins, ...) and oil treatments applied will reduce the deterioration rate and extend their useful life.
Factory refurbishments	Carry out a heavy refurbishment, including rewinding and other works which require de-tanking. This option has not been considered after researching the alternatives with suppliers as normally this works required transport to factory and re-commissioning when completed and their cost was in the range of a replacement.

List below the short list of those options which have been costed within this CBA workbook

Option no.	**Options considered**	**Decision**	**Comment**	**Spend area (from Table C1) (relevant only to adopted option)**	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	Baseline- The fleet of transformers continues the natural ageing process and diagnosis will start determining that most of them will need to be replaced	Rejected			£0.00	£0.00	£0.00	£0.00	
2	On-site refurbishments	Adopted	Most economic option	Network Investment Core Costs	£1.46	£2.39	£2.12	£1.53	
2.1	Sensitivity: 80% higher Refurbishment cost		NPV in year 32 becomes negative when the parameter is a 80% higher. Therefore, even a high deviation from the assumption in Option 1 would not change the decision taken.		£0.35	£0.48	-£0.20	-£0.98	
2.2	Sensitivity: 100% higher I&M cost		NPV only becomes negative in year 45 for a 100% increase in the parameter. This is due to the fact that the inspections & maintenance activities do not represent a high cost compared to other parameters.		£1.03	£1.29	£0.69	-£0.06	
2.3	Sensitivity: 97% higher failure probability in the refurbishment scenario than in the baseline scenario.		NPV in year 45 becomes negative when the parameter is a 97% higher than in the baseline scenario. Therefore, even a high deviation from the assumption in Option 1 would not change the decision taken.		£0.59	£0.87	£0.32	-£0.33	

Investment Business Case

CBA No.	65
Scheme/Project Name	BT21CN
Scheme/Project Owner	Howard Downey
Primary Investment Objective	BT21CN SPM : Justification for continuation of SPEN strategy of investing in mitigation of BT21CN risk via selections of lowest cost solution on a case by case basis using varied solutions including Private network build such Fibre Cables and Microwave plus alternative BT leased services.
Secondary Investment Objective (Engineering)	

Option no.	Options considered	Decision
1	All Private Nertwork Solution	
2	Cost Effective Mix of Private Network and Baseline BT Services	Adopted
3		

Background & Justification

BT21CN SPM : Justification for continuation of SPEN strategy of investing in mitigation of BT21CN risk via selections of lowest cost solution on a case by case basis using varied solutions including Private network build such Fibre Cables and Microwave plus alternative BT leased services.

Approach to the Options Appraisal

Baseline (Business as Usual) Scenario:

Migrate from obsolete BT Leased Line (Analogue / Kilostream) products to BT21CN compliant Leased Line products (SDH / Megastream) that will continue beyond the March 2018 deadline for termination by BT of Analogue / Kilostream.
For CAT1 services protection equipment is required to be swapped out.
The costs to replicate via SDH / Megastream those 132kV S/S that currently benefit from diverse and separate Analogue / Kilostream protection services have been included.
For the sake of comparison the requirement and subsequent additional costs for the provision of 132kV Black Start compliant SDH / Megastream services has been ignored.

Option 1:

Migrate from obsolete BT Leased Line (Analogue / Kilostream) products to BT21CN compliant private telecoms network service. before the March 2018 deadline for termination by BT of Analogue / Kilostream.
Solution consist of either the construction of microwave links using 3rd party hill sites where direct links can't be established or the installation of fibre cables between substations. The individual circuit solution are selected based on the lowest cost mix of the alternatives for the individual circuits exploiting synergies where such exist (i.e. multiple microwave links emanating from a single site are assumed to share the same infrastructure at the substation). Only private telecoms network solutions have been considered (No SDH / Megasteam considered in this option).

Term (years from first out flow)	NPV (£m)
16	-£11.87
24	-£18.03
32	-£23.88
45	-£32.31
first year of investment out flow	1

Option2:

As per the All private Network Solution but with the additional consideration of the use of SDH/Megastream where cost effective to do so.

Term (years from first out flow)	NPV (£m)
16	£2.76
24	£2.93
32	£2.83
45	£2.42
first year of investment out flow	1

Sensitivities

N/A

Appendix 1: Cost Benefit Analysis

Options considered	Comment
"do minimum" option	Migrate from obsolete BT Leased Line (Analogue / Kilostream) products to BT21CN compliant Leased Line products (SDH / Megastream) that will continue beyond the March 2018 deadline for termination by BT of Analogue / Kilostream. For CAT1 services protection equipment is required to be swapped out. The costs to replicate via SDH / Megastream those 132kV S/S that currently benefit from diverse and separate Analogue / Kilostream protection services have been included. For the sake of comparison the requirement and subsequent additional costs for the provision of 132kV Black Start compliant SDH / Megastream services has been ignored.
All Private Network Solution	Migrate from obsolete BT Leased Line (Analogue / Kilostream) products to BT21CN compliant private telecoms network service. before the March 2018 deadline for termination by BT of Analogue / Kilostream. Solution consist of either the construction of microwave links using 3rd party hill sites where direct links can't be established or the installation of fibre cables between substations. The individual circuit solution are selected based on the lowest cost mix of the alternatives for the individual circuits exploiting synergies where such exist (i.e. multiple microwave links emanating from a single site are assumed to share the same infrastructure at the substation). Only private telecoms network solutions have been considered (No SDH / Megasteam considered in this option).
Cost Effective Mix	As per the All private Network Solution but with the additional consideration of the use of SDH/Megastream where cost effective to do so.

List below the short list of those options which have been costed within this CBA workbook

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
Baseline									
1	All Private Nertwork Solution	Rejected	Least economic option		-£11.87	-£18.03	-£23.88	-£32.31	
2	Cost Effective Mix of Private Network and Baseline BT Services	Adopted	Most economic option	BT21CN	£2.76	£2.93	£2.83	£2.42	
3									
4									
5									

Investment Business Case

CBA No.	66
Scheme/Project Name	SPEN Voltage Control Relay Functional Enhancement Programme
Scheme/Project Owner	Alan Collinson
Primary Investment Objective	To accomodate more small-scale DG in a cost-effective manner
Secondary Investment Objective (Engineering)	To increase the flexibility of the distribution network by enhancing the functionality of current voltage control systems

Option no.	**Options considered**	**Decision**
0	Baseline – Implement the proposed voltage control relay programme	Accepted
1	Option 1 – Conventional reinforcement, Sensitivity 1 - "low" scenario uptake of PV	Rejected
2	Option 1 - Conventional reinforcement option Sensitivity 2 – "medium" scenario uptake of PV	
3	Option 1 - Conventional reinforcement Sensitivity 3 - "high" scenario uptake of PV	

Background & Justification

Voltage Control Relays - Enhananced Functionality for Advanced Network Voltage Control. This is not a conventional CBA analysis. It is a sensitivity ananlysis. It aims to illustrate the financial risk of selecting the conventional reinforcement solution, the cost of which is linked directly to LCT uptake volumes. Whereas the smart solution has a higher fixed cost, but its cost is largely insensitive to LCT volumes.

So, whilst the conventional solution is marginally preferable under the low uptake scenario, it is far worse under higher uptake scenarios.

This CBA uses the Voltage Control Relay solution as the baseline, as it is a "fixed cost" solution. This solution is compared with the conventional reinforcement solution, the cost of which is linked to the volumes of LCT uptake. This cost depenancy was assessed using the TRANSFORM Model.

Approach to the Options Appraisal

- The baseline solution is the proposed upgrade to the voltage control functionality, whilst the three options considered are in fact sensitivity analyses of the conventional solution based on three uptake scenarios for PV. This is because the baseline option is a fixed cost option, largely independent of volumes of PV uptake, whilst the costs associated with the conventional solution will be effected by the volumes of PV connected.
- Option 1 is a sensitivity analysis for the conventional solution , based on a “low” scenario PV uptake, with Option 2 the sensitivity analysis for a “medium” PV uptake and Option 3 for a “high” PV uptake

The cost-benefit sensitivity analysis was based on DECC’s uptake forecasts for photovoltaics (low, medium and high scenario), using the TRANSFORM Model. The TRANSFORM Model provided an indication of the costs required to accommodate the DECC PV uptake scenarios, based on a business as usual approach. The results from the TRANSFORM model are shown below:

SPM				
LV PV	Zero PV	Low PV	Medium PV	High PV
2012	0	0	0	0
2013	0	0	0	67,258
2014	0	67,254	874,490	1,570,798
2015	0	1,105,708	822,779	3,072,231
2016	412,163	239,211	2,786,818	4,770,445
2017	509,789	1,147,128	2,881,440	6,228,989
2018	553,430	1,552,155	6,464,478	9,225,387
2019	138,184	2,241,885	2,601,356	15,266,757
2020	1,276,175	2,630,964	9,248,280	18,901,686
2021	946,701	2,255,420	6,166,300	9,323,917
2022	4,156,142	4,317,544	3,344,946	24,495,959
2023	5,375,231	2,552,538	3,382,332	6,506,878
ED1	13,367,815	18,109,807	38,573,220	99,430,305
Transform Model Results (Model Version 3.3.2)				

SPD				
LV PV	Zero PV	Low PV	Medium PV	High PV
2012	0	0	0	0
2013	0	0	0	0
2014	0	0	0	0
2015	0	0	0	0
2016	0	0	0	302,590
2017	0	0	0	708,354
2018	1,932,945	1,932,945	2,263,673	3,576,617
2019	1,139,545	1,139,545	1,819,881	2,460,898
2020	899,537	899,537	2,332,069	4,567,880
2021	3,041,128	3,343,607	3,249,316	4,889,753
2022	5,440,325	5,443,104	6,928,281	8,450,185
2023	4,176,191	4,178,918	5,505,274	11,257,916
ED1	16,629,672	16,937,655	22,098,495	36,214,194

SPEN				
LV PV	Zero PV	Low PV (delta)	Med PV (delta)	High PV (delta)
2012	0	0	0	0
2013	0	0	0	67,258
2014	0	67,254	874,490	1,570,798
2015	0	1,105,708	822,779	3,072,231
2016	412,163	-172,952	2,374,655	4,660,872
2017	509,789	637,339	2,371,651	6,427,554
2018	2,486,375	998,725	6,241,777	10,315,630
2019	1,277,729	2,103,700	3,143,507	16,449,926
2020	2,175,713	1,354,789	9,404,636	21,293,853
2021	3,987,829	1,611,198	5,427,787	10,225,841
2022	9,596,468	164,180	676,759	23,349,677
2023	9,551,422	-2,819,967	-663,815	8,213,372
ED1	29,997,487	5,049,975	30,674,228	105,647,012
	£M	0.63	3.83	13.21
	PV Scenario	LOW	MED	HIGH

Notes: Converted to average over the 8 year period
TRANSFORM Model results are indicative for ED1 period, but not sufficiently robust to give full annual granularity

The majority of the conventional network interventions identified by the transform model include uprating of small transformers and installation of new transformers, along with splitting and adding LV feeders. Note that our best view PV uptake, based on the installed capacity over the past three years is aligned with the DECC low uptake forecast. The conclusions from the CBA indicate that, when considering the range of possible PV uptakes, the voltage control relay upgrade provides the most prudent approach as it is robust solution in terms of cost certainty (circa £8M during ED1) compared with the cost uncertainties associated with the conventional reinforcement approach of between £5M and £105M during ED1.

Customer Benefits

As an additional benefit, reducing the network voltage will also improve energy efficiency for our Customers. For every 1% reduction in average voltage, our customers will achieve an average energy efficiency improvement of between 0.5% and 1% (based on the extensive studies carried out by ESB[3] and WPD[4]). Therefore, based on a voltage reduction of 3% for six months of the year and a conservative assumption of 0.5% energy efficiency improvement per 1% voltage reduction, this translates to approximately 0.75% energy saving over the year. For an average customer who has an electricity consumption of approximately 3500kWhr/annum, this equates to an energy saving of 26.25kWhr/annum (or £3.94 at 15p/kWhr). In license area terms, customers within SPD with 2 million customers will save a total of £7.88M per annum, whilst customers within SPM with 1.5 million customers will save £5.91M per annum. Note that these customer benefits have not been included in the CBA.

Chosen Option - Voltage Control Relays

Advanced Network Voltage Control using modern Voltage Control Relays (with additional voltage settings), additional comms and central control

Option 1 - Alternative Sensitivity 1

PV uptake assumption is "best view" (low)

Term (years from first out flow)	NPV (£m)
16	£1.30
24	£1.76
32	£2.07
45	£2.39
first year of investment out flow	1

Option 1 - Alternative Sensitivity 2

PV assumption increased from low to medium

Term (years from first out flow)	NPV (£m)
16	-£12.94
24	-£16.44
32	-£18.78
45	-£21.20
first year of investment out flow	1

[3] E Diskin, T Fallon, G O'Mahony, C Power, *"Conservation Voltage Reduction and Voltage Optimisation on Irish Distribution Networks"*, CIRED 2012.
[4] J Woodruff, *"Network Monitoring Data - using and manipulating data to predict network behaviour"*, LCNF Conference, Brighton, November 2013.

Option 1 - Alternative Sensitivity 3

PV assumption increased from low to high

Term (years from first out flow)	NPV (£m)
16	-£54.61
24	-£69.68
32	-£79.78
45	-£90.22
first year of investment out flow	1

Appendix 1 - Cost Benefit Analysis (Excel Spreadsheet) Attached

Options considered / project name	Comment
Baseline - Voltage Control Relays	Advanced Network Voltage Control using modern Voltage Control Relays (with additional voltage settings), additional comms and central control
Option 1 - Alternative Sensitivity 1 (low)	Investment stategy based on business as usual conventional network reinforcement solutions. This option is based on the SPEN "best view" for load growth and PV uptake (PV uptake = low)
Option 2 - Alternative Sensitivity 2 (med)	As Option 1, but with medium PV uptake scenario
Option 3 - Alternative - Sensitivity 3 (high)	As Option 1, but with high PV uptake scenario

Option no.	Options considered	Decision	Comment	For the chosen option only, provide detail of where CBA expenditure included in this CBA is reported in the BPDT pack. e.g. LV swtichgear BPDT CV3 rows 15 to 22.	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	Alternative 1 Sensitivity 1	Rejected	PV uptake assumption is "best view" (low)		£1.30	£1.76	£2.07	£2.39	
2	Alternative Sensitivity 2	Rejected	PV assumption increased from low to medium		-£12.94	-£16.44	-£18.78	-£21.20	
3	Alternative Sensitivity 3	Rejected	PV assumption increased from low to high		-£54.61	-£69.68	-£79.78	-£90.22	
4	Baseline	Adopted							

Investment Business Case

CBA No.	67.1 & 67.2
Scheme/Project Name	SPEN LCT Monitoring Strategy
Scheme/Project Owner	Alan Collinson
Primary Investment Objective	To enable early identification of LV network areas approaching thermal or voltage limits due to LCT uptake and respond efficiently
Secondary Investment Objective (Engineering)	To improve performance and security of the LV network

Option no.	Options considered	Decision
0	Baseline – Business-as-usual Install LV network monitoring once customer complaints are recieved and/or an LV fuse has blown, then apply network intervention	Rejected
1	Option 1 – LCT Monitoring Strategy Identify LV networks approaching thermal or voltage limits early and install LV network monitoring followed by network intervention	Accepted
2	Option 2 – Pro-active LV Interventions Identify LV networks approaching thermal or voltage limits early and install network intervention	Rejected

Background & Justification

DECC have forecast significant growth in LCT uptake through RIIO-ED1 and beyond. This includes domestic PV, EV chargers and heat pumps. An increase in LCTs will impact the thermal loading and voltage in the distribution network and it will be vital to respond appropriately to ensure security and quality of network supply.

The business-as-usual approach to identifying areas of the LV network that are reaching capacity is based on assessment of MDI data from secondary substations and customer complaints. As there is no resolution of the loading of individual LV feeders (or feeder phases) from MDI data, network monitoring would then be installed reactively at the secondary substation to better understand network loading and to develop an appropriate reinforcement solution. This can take up to 12 months and during this time, customers may continue to experience quality of supply issues and existing assets are at risk of overloading and corresponding degradation. Alternatively , a solution may be identified without monitoring however this could be sub-optimal.

An LCT monitoring strategy has been developed for RIIO-ED1 to enable proactive, early identification of LCT growth hot spots on the HV and LV networks and to provide a robust framework with which to identify areas of the LV network that require monitoring to better understand the impact of LCT growth. Analysis of LV monitoring data will provide guidance on available network capacity and appropriate response to areas impacted by LCT growth.

Approach to the Options Appraisal

- The baseline solution is the business-as-usual approach where LV network monitoring and interventions are applied reactively following a reduction in quality or security of supply.
- Option 1 is based on application of the proactive LCT monitoring strategy to identify LCT hot spots early, followed by LV monitoring to better understand the loading of the network then targeted deployment of network interventions.
- Option 2 is based on deployment of LV interventions to affected areas from identification of LCT hot spots from existing network data sources. In this option, no LV monitoring would be installed.

The cost-benefit analysis was based on DECC's uptake forecasts for LCTs (SPEN 'best view'), as used in the TRANSFORM Model. The TRANSFORM Model provides an indication of the LV interventions and associated costs required during RIIO-ED1 and RIIO-ED2 to accommodate the uptake scenario.

An "additional scope of works factor" of 20% is applied to the baseline due to the reactive approach generally requiring additional works (e.g. transformer cable tail or pole degradation caused by overloading or failure, additional fuse replacements, customer liaison, etc).

A monitoring efficiency factor of 75% is applied to recognise that monitoring needs to be applied to more sites than will actually need to be reinforced, because it is not possible to identify with 100% centainty exactly which sites, which are currently close to being overloaded, but are not overloaded yet, will be overloaded in the future(if we could, there would be no need to monitor!). It has also been assumed that LV monitoring is deployed on average, one year prior to requiring an intervention. This will vary from network to network depending on the rate of LCT growth and clustering. The monitoring efficiency factor becomes the reinforcement efficiency factor in Option 2, where the reinforcement is carried out without monitoring, so the reinforcement is done at the sites where monitoring is carried out in option 2.

The conclusions from the CBA indicate that application of Option 1, the LCT monitoring strategy (including the cost of LV interventions) is the preferred approach.

<u>Chosen Option</u> *<u>(Includes engineering justification if not choosing the highest NPV)</u>*

The business-as-usual solution is rejected because of the high associated cost.

SPM

	Options considered	**Decision**	**Comment**	NPVs based on payback periods				
				16 years	24 years	32 years	45 years	DNO view
1	Option 1 – LCT Monitoring Strategy	Accepted		£0.93	£1.08	£1.20	£1.29	
2	Option 2 – Pro-active LV Intervention	Rejected	Higher cost-risk of reinforcing network sites that do not require reinforcement No feedback loop for improved identification of LCT hot spots from increased LV monitoring.	£0.55	£0.59	£0.62	£0.64	

SPD

	Options considered	**Decision**	**Comment**	NPVs based on payback periods				
				16 years	24 years	32 years	45 years	DNO view
1	Option 1 – LCT Monitoring Strategy	Accepted		£0.08	£0.06	£0.05	£0.04	
2	Option 2 – Pro-active LV Intervention	Rejected	Higher cost-risk of reinforcing network sites that do not require reinforcement No feedback loop for improved identification of LCT hot spots from increased LV monitoring.	-£0.00	-£0.02	-£0.04	-£0.06	

The volumes and costs (assuming £3000/installation) of monitors required in the two SPEN license are estimated to be:

Monitors	**Annnual Volume**	**Total Volume**	**Cost**	**Adjusted Volume**	**Adjusted Cost**
SPD	**107.5**	**820**	**£2.46M**	**871**	**£2.613M**
SPM	**81.25**	**620**	**£1.86M**	**502**	**£1.506M**
Total	**188.75**	**1440**	**£4.32M**	**1373**	**£4.119M**
Additional Cost saving					**£0.201M**

Note: the adjusted volumes are based on the ability to re-deploy 67 monitors from LCNF trial projects which will be completed by 2015.

Customer Benefits

Application of the LCT monitoring strategy will significantly improve quality and security of supply through early identification of network areas approaching thermal or voltage limits. Based on an average of 25 customers per LV feeder and assuming one network interruption per LV network requiring an intervention in the RIIO-ED1 period for the business-as-usual approach, circa 26,000 customer interruptions are avoided. Customer complaints will also reduc e significantly although these have not been included in the CBA. For a cost of £15.44 per customer interruption, this saves approximately £0.4m during RIIO-ED1.

Appendix 1 - Cost Benefit Analysis (Excel Spreadsheet) Attached

Option no.	Options considered	Decision	Comment	For the chosen option only, provide detail of where CBA expenditure included in this CBA is reported in the BPDT pack. e.g. LV swtichgear BPDT CV3 rows 15 to 22.	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	LCT Monitoring Strategy	Adopted			£0.93	£1.07	£1.17	£1.27	
2	Pro-active LV Intervention	Rejected	Cost-Risk of reinforcing many sites that dont require reinforcement		£0.54	£0.58	£0.61	£0.63	
3									
4									
5									

Option no.	Options considered	Decision	Comment	For the chosen option only, provide detail of where CBA expenditure included in this CBA is reported in the BPDT pack. e.g. LV swtichgear BPDT CV3 rows 15 to 22.	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	LCT Monitoring Strategy	Adopted			£0.08	£0.06	£0.05	£0.04	
2	Pro-active LV Intervention	Rejected	Cost-Risk of reinforcing many sites that dont require reinforcement		-£0.00	-£0.02	-£0.04	-£0.06	
3									
4									
5									

Investment Business Case

CBA No.	68.1
Scheme/Project Name	OHL Rebuild SPD
Scheme/Project Owner	Alan Collinson
Primary Investment Objective	To ensure a fit for purpose OHL network
Secondary Investment Objective (Engineering)	To build to a cost optimal design specification

Option no.	Options considered	Decision
1 (Baseline)	Rebuild 100% of normal weather rebuild to 50mm² AAAC conductor	Rejected
2	Rebuild 100% of normal weather rebuild to 100mm² AAAC conductor	Adopted
3	Rebuild 50% of normal weather rebuild to 100mm² AAAC conductor	Rejected

Background & Justification

Where the main line has been built to a construction specification that is no longer fit for pupose for the weather area where it has been erected, then it will need to be rebuilt. This cost-benefit analysis compares the standard conductors that are currently used when rebuilding 11kV lines in normal and severe weather areas to determine the optimal design specification for the rebuild. Where the line is being rebuilt in a severe weather area, our current specification is to install 100mm² AAAC "Oak" conductor and where it is being installed in a normal weather area our current specification is to install 50mm² AAAC "Hazel" conductor.

When selecting the optimal conductor size will be the losses that are incurred on the network will be assessed. Three options are considered: building in normal weather areas with 50mm² AAAC "Hazel" conductor; building in normal weather areas with 100mm² AAAC "Oak" conductor and building in normal weather areas using our 50mm² AAAC "Hazel" conductor for half of the lines and 100mm² AAAC "Oak" conductor for the other half.

In addition, there is a desire to introduce an element of future-proofing into the network as part of the rebuild programme in order to avoid the wasted expenditure of having to uprate a recently rebuilt 11kV overhead line (i.e. effectively having to rebuild the line again completely with a larger conductor).

Business as Usual Option (Baseline/Option 1)

Our baseline option (Option 1) where where the line is being rebuilt in a normal weather area we will install 50mm² AAAC "Hazel" conductor.

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*

The Option which returns the best NPV is Option 2, to rebuild 100% of normal weather to 100mm² AAAC "Oak" conductor as part of the rebuild programme. The much lower losses of the larger conductor means that it is cost beneficial to replace 100% as opposed to 50% of the network. By replacing 100% of the lines we will also be making the network more resilient and adaptable to load growth.

Approach to the Options Appraisal

- *Option 1 is always a 'do minimum'/ Business as usual Option. All the costs and benefits associated with the other options are relative to the do minimum Option (Option 1).*
- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

1. We have considered the maximum demand to be 72% as taken from the Transform model.
2. Calculation Period (years) 45
3. Assert Type OHL
4. Asset Voltage 11Kv
5. We have considered the losses of the 50mm² to be 4.91 MWhr/km/yr
6. We have considered the losses of the 100mm² to be 2.48 MWhr/km/yr

<u>Option 2</u>
Uprate 100% of normal weather rebuild to 100mm² AAAC "Oak" conductor

Term (years from first out flow)	NPV (£m)
16	£0.14
24	£0.35
32	£0.54
45	£0.82
first year of investment out flow	1

<u>Option 3</u>
Uprate 50% of normal weather rebuild to 100mm² "Oak" AAAC conductor and 50% to 50mm² "Hazel" AAAC conductor

Term (years from first out flow)	NPV (£m)
16	£0.07
24	£0.18
32	£0.27
45	£0.41
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	100% of normal weather rebuild to 50mm² AAAC conductor	Rejected	Separate programmes not cost effective		£0.00	£0.00	£0.00	£0.00	
2	100% of normal weather rebuild to 100mm² AAAC conductor	Adopted	Most economical solution		£0.14	£0.35	£0.54	£0.82	
3	50% of normal weather rebuild to 100mm² AAAC conductor	Rejected	Not most economical solution		£0.07	£0.18	£0.27	£0.41	

Investment Business Case

CBA No.	68.2
Scheme/Project Name	OHL Rebuild SPM
Scheme/Project Owner	Alan Collinson
Primary Investment Objective	To ensure a fit for purpose OHL network
Secondary Investment Objective (Engineering)	To build to a cost optimal design specification

Option no.	Options considered	Decision
1 (Baseline)	Uprate 100% of normal weather rebuild to $50mm^2$ AAAC conductor	Rejected
2	Uprate 100% of normal weather rebuild to $100mm^2$ AAAC conductor	Adopted
3	50% of normal weather rebuild to $100mm^2$ AAAC conductor	Rejected

Background & Justification

Where the main line has been built to a construction specification that is no longer fit for pupose for the weather area where it has been erected, then it will need to be rebuilt. This cost-benefit analysis compares the standard conductors that are currently used when rebuilding 11kV lines in normal and severe weather areas to determine the optimal design specification for the rebuild. Where the line is being rebuilt in a severe weather area, our current specification is to install 100mm² AAAC “Oak” conductor and where it is being installed in a normal weather area our current specification is to install 50mm² AAAC “Hazel” conductor.

When selecting the optimal conductor size will be the losses that are incurred on the network will be assessed. Three options are considered: building in normal weather areas with 50mm² AAAC “Hazel” conductor; building in normal weather areas with 100mm² AAAC “Oak” conductor and building in normal weather areas using our 50mm² AAAC “Hazel” conductor for half of the lines and 100mm² AAAC “Oak” conductor for the other half.

In addition, there is a desire to introduce an element of future-proofing into the network as part of the rebuild programme in order to avoid the wasted expenditure of having to uprate a recently rebuilt 11kV overhead line (i.e. effectively having to rebuild the line again completely with a larger conductor).

Business as Usual Option (Baseline/Option 1)

Our baseline option (Option 1) where where the line is being rebuilt in a normal weather area we will install 50mm² AAAC “Hazel” conductor.

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*

The Option which returns the best NPV is Option 2, to rebuild 100% of normal weather to 100mm² AAAC “Oak” conductor as part of the rebuild programme. The much lower losses of the larger conductor means that it is cost beneficial to replace 100% as opposed to 50% of the network. By replacing 100% of the lines we will also be making the network more resilient and adaptable to load growth.

Approach to the Options Appraisal

- *Option 1 is always a 'do minimum'/ Business as usual Option. All the costs and benefits associated with the other options are relative to the do minimum Option (Option 1).*
- *The period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.*

1. We have considered the maximum demand to be 83% as taken from the Transform model.
2. Calculation Period (years) 45
3. Assert Type OHL
4. Asset Voltage 11Kv
5. We have considered the losses of the 50mm² to be 4.91 MWhr/km/yr
6. We have considered the losses of the 100mm² to be 2.48 MWhr/km/yr

Option 2
Uprate 100% of normal weather rebuild to 100mm² AAAC "Oak" conductor

Term (years from first out flow)	NPV (£m)
16	£0.15
24	£0.36
32	£0.54
45	£0.81
first year of investment out flow	1

Option 3
Uprate 50% of normal weather rebuild to 100mm² "Oak" AAAC conductor and 50% to 50mm² "Hazel" AAAC conductor.

Term (years from first out flow)	NPV (£m)
16	£0.08
24	£0.18
32	£0.27
45	£0.40
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Option no.	Options considered	Decision	Comment	Spend area (from Table C1) (relevant only to adopted option)	NPVs based on payback periods				
					16 years	24 years	32 years	45 years	DNO view
1	100% of normal weather rebuild to 50mm² AAAC conductor	Rejected	Separate programmes not cost effective		£0.00	£0.00	£0.00	£0.00	
2	100% of normal weather rebuild to 100mm² AAAC conductor	Adopted	Most economical solution		£0.15	£0.36	£0.54	£0.81	
3	50% of normal weather rebuild to 100mm² AAAC conductor	Rejected	Not most economical solution		£0.08	£0.18	£0.27	£0.40	