2.3 Annex

SP Energy Networks 2015–2023 Business Plan

Cost benefit analysis

SP Energy Networks

June 2013

SP ENERGY NETWORKS

Investment Business Case

CBA No.	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) out with 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

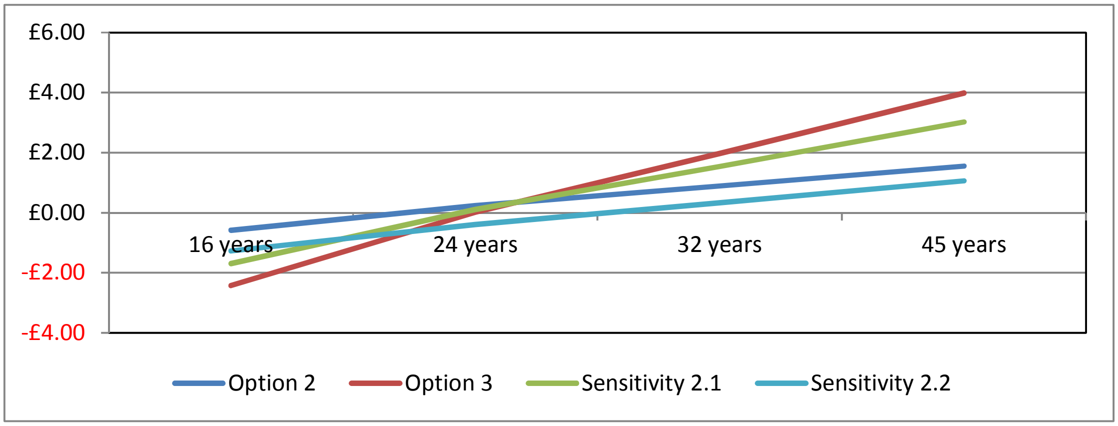
The EU has indicated their intention to specify a maximum losses figure for distribution transformers. This will have a knock on cost impact. The ENA commissioned a report on the potential impact of the proposed losses reduction. A sensitivity was added here, for information only, indicating the impact 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 significant 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

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	£0.00
2	on top of baseline target high loss units (pre 1962) out with RMU programme based on load	Adopted		Technical losses and other environmental	-£0.58	£0.24	£0.89	£1.55	
3	on top of baseline, replace remainder of all high loss (pre 1962) HV distribution transformers in ED1	Rejected	Rejected on the basis of deliverability constraint and system access		-£2.42	£0.01	£1.97	£3.98	
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		-£1.70	£0.10	£1.54	£3.02	
2.2	sensitivity 2 - Option 2 with estimate of EU losses/costs		For information only		-£1.27	-£0.40	£0.32	£1.06	

Investment Business Case

CBA No.	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 out with 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

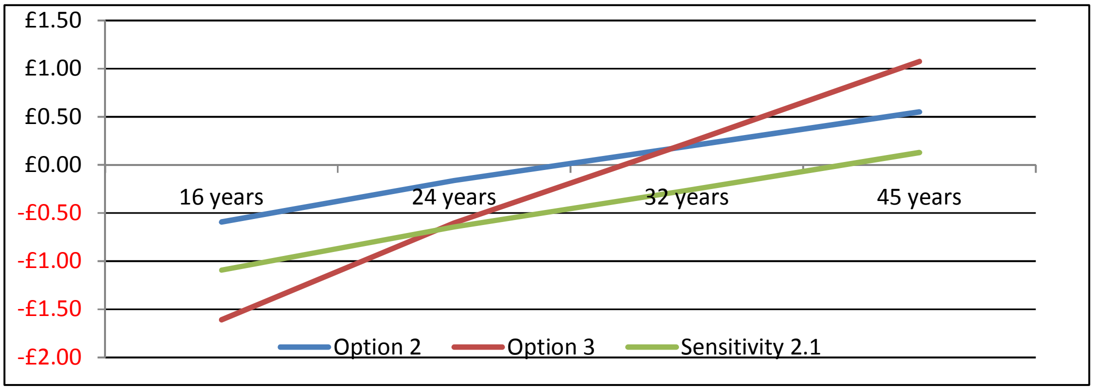
The EU has indicated their intention to specify a maximum losses figure for distribution transformers. This will have a knock on cost impact. The ENA commissioned a report on the potential impact of the proposed losses reduction. A sensitivity was added here, for information only, indicating the impact 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.



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

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

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	on top of baseline target high loss (pre 1962) and poor condition units out with RMU programme based on load	Adopted		Technical losses and other environmental	-£0.59	-£0.16	£0.19	£0.55	
3	replace all high loss (pre 1962) HV distribution transformers in ED1	Rejected	Rejected on the basis of deliverability constraint and system access		-£1.61	-£0.60	£0.22	£1.07	
2.1	sensitivity 2 Option 2 with estimated EU losses/costs		For information only		-£1.09	-£0.64	-£0.26	£0.13	

Investment Business Case

CBA No.	3
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 a 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.

Business as Usual Option (Baseline/Option 1)

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.

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

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.*

<u>Assumptions Made:</u>

<u>Volumes used:</u>
Utilising quality data SPEN have identified that 378 11kV OCBs will be retroffited with VCB moving portions in ED1 and 688 OCB's will be replaced under switchboard replacements i.e. by installing Fixed Pattern Metal Enclosed Switchgear. 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 implemented.

<u>Potential Post Fault Maintenance Cost savings :</u>
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 calculated. The % rate was then applied to the volume of OCB's each year.

<u>Potential Oil and Handling Cost savings:</u>
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.

<u>Option 2:</u>
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	£16.15
24	£14.89
32	£10.28
45	£6.42
first year of investment out flow	1

Option 3:
To Refurbish Only. This was rejected because our strategy is to not refurbish units at end of life. We have used a refurbish volume of 199 per year.

Term (years from first out flow)	NPV (£m)
16	£21.89
24	£15.85
32	£12.86
45	£9.71
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	£21.86
24	£21.88
32	£13.61
45	£6.49
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

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 - 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.		£16.15	£14.89	£10.28	£6.42	
3	Refurbish Only	Rejected	this option is not valid as refurbishment of end of life switchgear does not meet the strategy		£21.89	£15.85	£12.86	£9.71	
4	Retrofit Only	Rejected	this option cannot be delivered as not all types of switchgear are capable of being retrofitted		£21.86	£21.88	£13.61	£6.49	

Investment Business Case

CBA No.	4
Scheme/Project Name	Black Start - Substation Resilience
Scheme/Project Owner	Alyn Jones
Primary Investment Objective	Meet our obligation and our stakeholder expectations.
Secondary Investment Objective (Engineering)	Validate the planned approach to be taken by SPEN in achieving the required level of resilience

Option no.	Options considered	Decision
1	Baseline- installing a standby generator at all Grid & Primary sites which have a 'significant' AC or DC requirement.	Rejected
2	Generation applied to all Grid Sites consistent with SPT, 6 operational muster locations, plus 72hr battery capacity batteries in Primaries with Significant DC loading	Rejected
3	Generation/72 hr battery capacity at Grids, generation at 6 operational muster locations, plus 72hr capacity battery capacity/Battery DC load disconnection schemes applied in Primaries with Significant DC loading	Adopted
4	Generation/72 hr battery capacity at Grids, generation at 6 operational muster locations and battery DC load disconnection schemes applied in Primaries with Significant DC loading	Rejected

Background & Justification

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. 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.

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.

Grid sites 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 to the site essential services.

Grid sites without an AC motive power dependency for circuit breakers and associated disconnector's and all Primary Sites 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. The housing of the new battery and charger unit may require site work to enable the larger unit to be accommodated; in some case this may require civil works or installation of suitable external cabinets.

At Primary sites 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 load disconnection will be implemented.

Where such 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.

Load disconnection 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 Sites 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/Option 1)

Baseline case is based on installing a standby generator at all Grid & Primary sites, which 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 Sites 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.

Conclusion - meets engineering requirements but is excessively expensive

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

As a result of the various considerations, we have decided to use (Option 3) 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. This option has been chosen as it has a balanced portfolio of solutions and balanced engineering/societal risk. The reasoning for not using the highest NPV value, Option 4 is because of the combined risks of the over reliance on a single solution, and anticipated DC relay mortality rate, resulting from the power down, preventing or delaying network and customer restoration safely and efficiently.

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 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 2:

Fit standby generation to all Grid Sites 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.

Sites 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	£22.00
24	£29.71
32	£35.87
45	£43.64
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.

Option 3:

Fit standby generation to all Grid Sites 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 sites.

Sites 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	£25.16
24	£33.77
32	£40.56
45	£49.03
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.

Option 4:

Fit standby generation to all Grid Sites 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).

Sites 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.

Sites 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	£26.67
24	£35.68
32	£42.73
45	£51.46
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.

Sensitivities

N/A

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Option 1- Base Case - Global LV generator installation	Considered too expensive and over complicated for all substation configurations
Option 2 - 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 3 - 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
Option 4 - 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)
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
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

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- Global LV generator installation	Rejected	Considered too expensive and over complicated for all substation configurations		£0.00	£0.00	£0.00	£0.00	
2	Combination of solutions portfolio 1	Rejected	Likely to come across engineering/accommodation difficulties to deliver this solution		£22.00	£29.71	£35.87	£43.64	
3	Combination of solutions portfolio 2	Adopted	Balanced portfolio and balanced engineering/societal risk		£25.16	£33.77	£40.56	£49.03	
4	Combination of solutions portfolio var2	Rejected	Electronic relay mortality rates due to loss of DC raises risk of Safety to Staff/Public and assets. Also likely to add significant risk to restoration profile		£26.67	£35.68	£42.73	£51.46	

Investment Business Case

CBA No.	5
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	-£28.50
24	-£24.01
32	-£21.95
45	-£19.31
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	-£22.43
24	-£18.74
32	-£17.03
45	-£14.86
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	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			-£33.23	-£28.12	-£25.78	-£22.79	
2.1	Sensitivity 2.1- Reduce Pole Replacement Costs	Rejected			-£26.22	-£22.03	-£20.10	-£17.64	

Investment Business Case

CBA No.	6
Scheme/Project Name	Smart Solutions in the reinforcement of the Chester 33kV group
Scheme/Project Owner	Alan Collinson
Primary Investment Objective	To defer the replacement of RMUs in order to provide a cost saving to the customer whilst maintaining a secure supply
Secondary Investment Objective (Engineering)	Replacement of RMUs at or above fault break rating

Option no.	**Options considered**	**Decision**
1	Baseline- replace 7 RMUs over a 4 year period	Rejected
2	Defer Replacement of RMUs by utilising a smart solution	Adopted
2.1	Reduce Deferment period to 8 years	For information only

Background & Justification

The authorised reinforcement of the Chester 33kV group (Chester, Guilden Sutton, Crane Bank) is to install an additional Grid transformer at Saltney Grid substation. Unfortunately, whilst resolving the power flow issues, the addition of a fourth Grid transformer into the Chester group also creates fault level issues on the 33kV network.

Our policy is that all switchgear should be operated within its “fault break” capability, whilst any exceedances of “fault make” duty may be managed operationally as an interim solution until such time as it becomes necessary to replace the switchgear. Our 33kV fault level design policy limit is 1000MVA, but there are still significant numbers of 750MVA rated switchgear on the SP Manweb network. Therefore, it is our accepted policy to replace 750MVA switchgear with 1000MVA switchgear if this removes fault break exceedance issues.

Based on network studies of the Chester Group there are eleven 33kV RMUs as well as the 33kV switchboard at Guilden Sutton that would be close to or above their rating with the installation of the Saltney Grid Transformer. Of these, one was replaced and the Guilden Sutton switchboard is due to be replaced as part of the DPCR5 switchgear replacement programme. In addition, a further three RMUs are planned to be replaced as part of the RIIO-ED1 asset replacement programme. This leaves seven RMUs close to or above their fault break rating. Of these, five would be above rating. However, the other two outdoor breakers are potentially below rating during lower fault level periods. More detailed analysis shows that the worst case scenario fault levels are only likely to occur when the two embedded generation sites are both running simultaneously and at full export capacity. The fault levels at Huntington 1, Huntington 2 drop to below 95% when both the Huntington and Gowy Landfill generators are not generating. There is also some uncertainty as to the exact fault contribution of the new Grid transformer due to manufacturing tolerances – the technical specification will define an acceptable impedance range for the transformer but the exact impedance (and hence fault contribution) will not be known until the new transformer is actually built. The nominal impedance is 18% (0.3pu), but typical units can be in the range 0.27 to 0.33 pu.

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

To replace all seven RMUs which are close to or above their fault break rating. Of these, five would be above rating, however, the other two outdoor breakers are potentially below rating during lower fault level periods.

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

It is proposed to replace five of the seven RMUs that are not currently part of the asset replacement programme during the ED1 period. (Option 2) The remaining fault level issue will be managed by using the newly developed fault level monitor to assess the real-time fault levels at the Huntington 33kV busbar. If the measured fault levels are found to be unacceptably high, the fault levels on the network can be reduced by temporary network reconfiguration.

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 assumptions made within this CBA are that the deferral period by using smart solutions is 10 years. We have also assumed that we can replace 2 RMU per annum.

Option 1 (Baseline)
We would replace 7 RMUs over a 4 year period.

Option 2
Defer Replacement of 2 of the RMUs by utilising a smart solution.

Term (years from first out flow)	NPV (£m)
16	£0.26
24	£0.24
32	£0.21
45	£0.19
first year of investment out flow	1

Sensitivities

Sensitivity 2.1

Within this sensitivity we felt that it was important to try and underestimate the period which the smart solution will defer the replacement. We used an 8 year deferral period as opposed to 10 years which is the most accurate length of time. This reaffirms our decision that deferring the replacement time is cost beneficial.

Term (years from first out flow)	NPV (£m)
16	£0.18
24	£0.16
32	£0.14
45	£0.12
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Attach CBA spreadsheet here =➔

Options considered	Comment
Option 1- Baseline	We will replace 7 RMU over a 4 year period
Option 2- Defer Replacement by utilising a smart solution	We will replace the 7 RMU over a 13 year period utilising smart technologies. We will replace the first 5 RMU in 2016-2018 and will delay replacement of the last 2 RMU's until 2028-2029.
Sensitivity 2.2- Reduce Deferment period to 8 years	We will use option 2 and decrease the time of derral by 2 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- replace 7 RMU over a 4 year period	Rejected			£0.00	£0.00	£0.00	£0.00	
2	Defer Replacement by utilising a smart solution	Adopted	As there are no engineering reasons for not utilising this technology we have chosen the highest NPV		£0.26	£0.24	£0.21	£0.19	
2.2	Reduce Deferment period to 8 years		For information only		£0.18	£0.16	£0.14	£0.12	

Investment Business Case

CBA No.	7
Scheme/Project Name	Crewe Reinforcement- Utilising Phase shifting transformer
Scheme/Project Owner	Alberto Elena de Leonardo
Primary Investment Objective	The installation of smart grid solutions may save building a new distribution line.
Secondary Investment Objective (Engineering)	Establishing a new 132 kV circuit in order to support demand growth and secure the group.

Option no.	Options considered	Decision
1	Baseline Scenario - Conventional solution: current reinforcement strategy with the installation of new 132 kV circuit to resolve thermal capacity issue.	Rejected
2	Smart grid solution option: phase shifting transformer installation.	Adopted
2.1	Delay re-build after installing PST reduced by 3 years uneconomic	For information only

Background & Justification

We have engaged Smart Grid Solutions to assist in the identification and appraisal of alternative network investments. Phase shifting transformers was one of the solutions considered.

Investing in smart solutions during this price control period will allow the enabled network nodes to participate in active network management to provide us with the flexibility to integrate additional future demand and generators with minimum outages.

If the maximum demand of a 132 kV distribution demand group exceeds the value assessed to restore the full group demand for n-1 outages, there is a possibility to put the system at risk. This could result in the disconnection of the demand group. The baseline/ conventional solution would consist of building new 132 kV circuits between the referred demand group and other 132 kV substations in order to increase the maximum demand ratings. We have discovered through carrying out Cost Benefit Analysis that the installation of a phase shifting transformer (PST) between the site and an existing power line which is open on the site would parallel the EHV system. The phase shifting transformer would allow us to control the power flow through the lines and would allow the network to be balanced. These benefits would remove the need of building the new 132 kV circuit.

We currently do not utilise phase shifting transformers and as a result the risks may be considered high. We will need to purchase a second spare PST in order that we have a replacement should the one in service become faulty.

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

The Baseline Scenario identified 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. The profile for this option is over a significant number of years due the anticipated timescales associated with the planning/consenting of the 132kV circuit.

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

Our final chosen Option is Option 2; to install a 132kV Phase Shift Transformer (PST) 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 with approximately a sixteen degree voltage angle difference between them. If this split point were closed it would cause 132kV power flow issues and fault levels to increase above plant ratings in several 33kV groups and is therefore always operated 'open'. The use of PST 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 these assessments indicate it is viable to install a PST then it could have the potential to significantly increase supply security/capacity availability in the Crewe/Lostock Demand group. This would defer the conventional reinforcement with reduced environmental impact when compared with the conventional reinforcement solutions. The connection of the PST would increase 33kV fault levels requiring switchgear to be replaced and therefore a provisional sum of £2m has been included within the overall estimate. The installation of a PST 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 potential smart solution from their perspective and reach an agreement. The alternative conventional options involve significant 132kV overhead lines to be constructed with the risk of a significant fluctuation in cost if the ratio of cable to overhead line increases following the planning/consenting of the circuit. Given that there is a level of uncertainty associated with installing a PST at Crewe it is proposed to also progress some of the pre-engineering works associated with the conventional solution to mitigate some of the risk of the PST being found to be unviable following detailed analysis and liaison with National Grid/WPD.

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:
Install a Phase Shift Transformer at Crewe Grid to connect the Cellarhead GSP and Fiddlers Ferry/Carrington GSP Group.

Term (years from first out flow)	NPV (£m)
16	£6.58
24	£8.86
32	£10.38
45	£11.95
first year of investment out flow	1

Option 3:
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 proposed that it will not be progressed any further.

Term (years from first out flow)	NPV (£m)
16	-£3.89
24	-£5.38
32	-£6.38
45	-£7.40
first year of investment out flow	1

Sensitivities

N/A

Appendix 1: Cost Benefit Analysis

Attach CBA spreadsheet here =➔

Options considered	Comment
Option 1 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. The profile for this option is over a significant number of years due the anticipated timescales associated with the planning/consenting of the 132kV circuit.
Option 2 is to install a Phase Shift Transformer at Crewe Grid to connect the Cellarhead GSP and Fiddlers Ferry/Carrington GSP Group.	Option 2 is to further explore the feasibility, and if appropriate following detailed analysis, to install a 132kV Phase Shift Transformer (PST) 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 with approximately a sixteen degree voltage angle difference between them. If this split point were closed it would cause 132kV power flow issues and fault levels to increase above plant ratings in several 33kV groups and is therefore always operated 'open'. The use of PST 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 these assessments indicate it is viable to install a PST then it could have the potential to significantly increase supply security/capacity availability in the Crewe/Lostock Demand group. This would defer the conventional reinforcement with reduced environmental impact when compared with the conventional reinforcement solutions. The connection of the PST would increase 33kV fault levels requiring switchgear to be replaced and therefore a provisional sum of £2m has been included within the overall estimate. The installation of a PST 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 potential smart solution from their perspective and reach an agreement. The alternative conventional options involve significant 132kV overhead lines to be constructed at a estimated cost of over £20m and with the risk of a significant fluctuation in cost if the ratio of cable to overhead line increases following the planning/consenting of the circuit. Given that there is a level of uncertainty associated with installing a PST at Crewe it is proposed to also progress some of the pre-engineering works associated with the conventional solution to mitigate some of the risk of the PST being found to be unviable following detailed analysis and liaison with National Grid/WPD.
Option 3 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 to 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. The investment profile for this option is over a significant number of years due the anticipated timescales associated with the planning/consenting of the 132kV circuit.
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
1 (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.		£0.00	£0.00	£0.00	£0.00	
2	To install a Phase Shift Transformer 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.		£6.58	£8.86	£10.38	£11.95	
3	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.		-£3.89	-£5.38	-£6.38	-£7.40	

Investment Business Case

CBA No.	8
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	£3.39
24	£5.59
32	£7.74
45	£11.00
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	£3.39
24	£5.59
32	£8.34
45	£13.33
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	£4.55
32	£7.80
45	£13.30
first year of investment out flow	1

Option 5:

Underground Replacement

Term (years from first out flow)	NPV (£m)
16	-£2.65
24	-£2.01
32	£0.35
45	£4.96
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.

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	Repairing the mural wiring on failure is not an acceptable option.		£0.00	£0.00	£0.00	£0.00	
2	Like for Like Replacement	Rejected	Renewing the mural wiring on a "like for like" basis, where technically feasible.		£3.39	£5.59	£7.74	£11.00	
3	Renewing the mural wiring on a "like for like" basis every 25 years, where technically feasible.	Adopted	Renewing the mural wiring on a "like for like" basis every 25 years, where technically feasible.	Network Investment Core Costs	£3.39	£5.59	£8.34	£13.33	
4	Protected Mural Wiring Replacement	Rejected	Renewing the mural wiring on a "like for like" basis, where technically feasible but applying mechanical and UV protection to the		£2.56	£4.55	£7.80	£13.30	
5	Underground Replacement	Rejected	Cost of undergrounding the service is considerably higher than renewing the mural wiring.		-£2.65	-£2.01	£0.35	£4.96	

Investment Business Case

CBA No.	9
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. 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	£3.00
24	£2.64
32	£2.24
45	£2.08
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	£2.88
24	£2.48
32	£2.37
45	£2.40
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	£3.05
24	£2.76
32	£2.39
45	£2.28
first year of investment out flow	1

Sensitivity 2.2
Increase refurb cost by 5%

Term (years from first out flow)	NPV (£m)
16	£3.00
24	£2.63
32	£2.20
45	£2.03
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.

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	Least cost effective		£0.00	£0.00	£0.00	£0.00	
2	Replace pole mounted transformers with refurbished transformers	Adopted	While not the lowest cost option in the long term, when combined with the customer service and workload aspects, this option achieves the optimal solution.	Network Investment Core Costs	£3.03	£2.67	£2.25	£2.08	
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.		£3.05	£2.76	£2.39	£2.28	
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.		£3.00	£2.63	£2.20	£2.03	
3	Reuse existing pole mounted transformers	Rejected	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.		£2.93	£2.50	£2.37	£2.40	

Investment Business Case

CBA No.	10
Scheme/Project Name	Real Time Thermal Rating (RTTR) Transformer
Scheme/Project Owner	Alberto Elena de Leonardo
Primary Investment Objective	Obtain additional capacity on our network and therefore the installation of reinforcement transformers can be deferred.
Secondary Investment Objective (Engineering)	Engage with Smart Grid Solutions to assist in the identification and appraisal of alternative network investments.

Option no.	Options considered	Decision
1	"Do minimum" option - Conventional solution: current reinforcement strategy with the installation of new 33/11 kV transformers to resolve thermal capacity issue in primary substations.	Rejected
2	Smart grid solution option: real time thermal rating installation.	Adopted

Background & Justification

We have engaged Smart Grid Solutions (SGS) to assist in the identification and appraisal of alternative network investments. We have identified several cases where low to medium risk innovative solutions, which should be available in appropriate timescales, can offer an alternative or complement conventional reinforcement schemes. Real Time Thermal Rating (RTTR) Transformer + Monitoring was one of the solutions considered.

In considering the application of real time ratings and fault level monitoring, SGS were cognisant of our desire to apply more conservative thresholds for reinforcement. This has limited the opportunity to deploy alternative solutions since the new thresholds effectively 'create' immediate threshold breach situations and it has been assumed that these will be resolved in a conventional manner with some urgency rather than to seek to deploy a smart solution. In the application of real time thermal ratings, SGS identified a number of criteria that must be met before the solution was considered. The demand must not have exceeded the firm capacity of the asset, the demand must be correlated with seasonal temperature and there should be some uncertainty of the evolution of demand over time. Each of these conditions creates the opportunity for a smarter solution to be considered.

Business as Usual Option (Baseline/Option 1)

Conventional solution: current reinforcement strategy with the installation of new 33/11 kV transformers to resolve thermal capacity issue in primary substations.

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

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. This returns the best NPV significantly compared to our baseline/ business as usual option.

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) The unit cost of switchgear must be multiplied by the number of switches/circuit breakers contained on the board to replace.
2) We consider that the installation of RTTR on a site defers the reinforcement of the primary transformer a certain number of years.
3) The costs of inspections and maintenance are accumulative through the years as we install new equipments on the network.
4) The replacement of the switchgear involves a different cost in inspection and maintenance compared to the existing programmes.
5) The new gas switchgear requires a lower maintenance cost than the old oil switchgear. Therefore the I&M cost is calculated as the incremental cost, which results in benefit.

6) The costs are considered as negative values and the benefits as positive values.

Option 2:

The installation of real time thermal rating (RTTR) in those primary substations at 95% of 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.

Term (years from first out flow)	NPV (£m)
16	£0.62
24	£0.56
32	£0.51
45	£0.45
first year of investment out flow	1

Sensitivities

N/A

Appendix 1: Cost Benefit Analysis

Attach CBA spreadsheet here =➔

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	Rejected			£0.00	£0.00	£0.00	£0.00	
2	Smart grid solution option: real time thermal rating (RTTR)	Adopted			£0.62	£0.56	£0.51	£0.45	

Investment Business Case

CBA No.	11
Scheme/Project Name	Replace end of life RTUs
Scheme/Project Owner	Patrick Dolan
Primary Investment Objective	Replace end of life RTUs
Secondary Investment Objective (Engineering)	Sustainable control with functionality required for future network requirements

Option no.	**Options considered**	**Decision**
1	Baseline- Programme based on the installation of an RTU solution, bespokely engineered to support Legacy Protocols and Data Models	Rejected
2	Programme based on the installation of an RTU solution, based on industry standard protocol support and support for international standards for substation automation	Rejected
3	Programme based on the installation of an RTU solution, based on industry standard protocol support and international standards for substation automation - Extended timescales for population replacement	Adopted

Background & Justification

The main drivers for the replacement of 1st generation RTUs are obsolescence and issues associated with support. These RTUs communicate using bespoke protocols and are limited in their capacity to monitor and control additional plant and in their ability 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 bespokely 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.

Bespokely 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 suppliers 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.

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 bespokely developed to support legacy Ferranti protocols and require minimal alteration to the telecoms network.

The CBA considers procuring and installing RTUs bespokely 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 until they are replaced. An extended programme has not been considered for the bespokely engineered RTU solution as we have assumed that bespokely engineered RTUs will be 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 effectively fenced off from the benefits of innovation in this market. We will also be limited in terms of the development of more advanced network control systems capable of active network management and other smart grid initiatives.

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

Carry out a programme which replaces the current legacy RTU’s with a New RTU solution bespokely engineered to support legacy protocols within ED1.

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

Carry out a programme which Install’s RTU capable of supporting Industry Protocols and Standards for Substation Automation & Invest in required Telecoms Development over an extended period.

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 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 bespokley engineered RTU and due to the timescales associated with the extended programme option modelled.*

<u>Baseline/ Option 1</u>

- Assumed that bespoke MK3 / DSP4 Compact and Modular RTUs will have an asset life of 12 years as it is 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 omitted from the CBA

<u>Option 2</u>

Programme to Install RTU capable of supporting Industry Protocols and Standards for Substation Automation & Invest in required Telecoms Development within ED1.

Within this option it was 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
- 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 is required independent of the RTU installation strategy choice is made has been omitted from the CBA.

Term (years from first out flow)	NPV (£m)
16	-£2.81
24	-£3.83
32	-£0.28
45	£1.29
first year of investment out flow	1

Option 3

Programme to Install RTU capable of supporting Industry Protocols and Standards for Substation Automation & Invest in required Telecoms Development over an extended period.

Assumptions:

- 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 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 is required independent of the RTU installation strategy choice is made has been omitted from the CBA

Term (years from first out flow)	NPV (£m)
16	£1.30
24	£1.58
32	£5.74
45	£8.51
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	Costed as Option 1 Basecase
New RTU solution based on industry standard RTU protocols support and Substation Automation Standards	Costed as Option 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	Costed as Option 3
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 allow to fail

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 Bespokely Engineered to support Legacy Protocols and Data Models	Rejected	Long time other solutions are more cost effective and open up many possibilities for development		£0.00	£0.00	£0.00	£0.00	
2	New RTU solution based on industry standard RTU protocols support and Substation Automation Standards	Rejected	Move to industry standard protocols and subsequent development to telecoms network, sets a good foundation for Smart Grid initiatives to be built upon		-£2.81	-£3.83	-£0.28	£1.29	
3	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	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		£1.30	£1.58	£5.74	£8.51	

Investment Business Case

CBA No.	12
Scheme/Project Name	33kV Transformer Refurbishments SPD
Scheme/Project Owner	Carlos Ara
Primary Investment Objective	Guarantee the reliability of the network with smart and effective investment alternatives.
Secondary Investment Objective (Engineering)	Manage the ageing primary transformer fleet and explore refurbishment interventions to achieve life extension and therefore reduce and delay the capital expenditure required to replace the high percentage of the fleet due to reach end of life during the coming years.

Option no.	Options considered	Decision
1	Baseline- 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.	Rejected
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. 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.	Adopted

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.

Business as Usual Option (Baseline/Option 1)

Continue with 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.

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

To carry out on-site refurbishments (Option 2). 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.

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.*

A fleet of 85 33/11kV Transformers in poor condition (HI5) has been identified for a possible refurbishment during ED1. They are 63 HI3 and 22 HI4 presenting a very poor external condition which will accelerate the deterioration process 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 improve the units condition to HI3 or HI2 and extend the asset life considerably.

For each of the two options selected for CBA, the predicted fleet Health Index movements during the period have been calculated, according to the Primary Transformers deterioration model. The units will be replaced as soon as possible once they reach HI5. As a result, the replacement capex is distributed very differently along the years on each option resulting in a different effect on the NPV. The Inspection & Maintenance is slightly different in the two options as refurbishment of a unit will avoid I&M cost for that year. Also the failure probability and their related costs, as CI/CML or repair cost, have been calculated according to the fleet condition for each year.

The following considerations were not used as CBA options:

Replacements after failure- To 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.

Early replacements- To 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.

Factory refurbishments- To 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.

The following were used in our CBA analysis:

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. We decided to adopt On-site Refurbishments option. 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	**£2.27**
24	**£3.42**
32	**£3.71**
45	**£3.01**
first year of investment out flow	1

Sensitivities

Sensitivity 1.1:
80% higher Refurbishment cost. NPV in year 45 becomes negative when the parameter is a 80% higher. Therefore, even a high deviation from the assumption in Option 2 would not change the decision taken.

Term (years from first out flow)	NPV (£m)
16	£0.38
24	£1.04
32	£1.00
45	-£0.03
first year of investment out flow	1

Sensitivity 2.2 :

2-fold higher I&M cost. NPV in year 45 does not vary significantly for a 2-fold 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.

Term (years from first out flow)	NPV (£m)
16	£2.14
24	£3.20
32	£3.40
45	£2.57
first year of investment out flow	1

Sensitivity 2.3:

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 2 would not change the decision taken.

Term (years from first out flow)	NPV (£m)
16	£0.76
24	£1.38
32	£1.24
45	-£0.03
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.

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	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.	Network Investment Core Costs	£2.27	£3.42	£3.71	£3.01	
2.1	Sensitivity: 80% higher Refurbishment cost		NPV in year 45 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.		£0.38	£1.04	£1.00	-£0.03	
2.2	Sensitivity: 2-fold higher I&M cost		NPV in year 45 only varies a 15% 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.		£2.14	£3.20	£3.40	£2.57	
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.		£0.76	£1.38	£1.24	-£0.03	

Investment Business Case

CBA No.	13
Scheme/Project Name	33kV Transformer Refurbishments SPM
Scheme/Project Owner	Carlos Ara
Primary Investment Objective	Guarantee the reliability of the network with smart and effective investment alternatives.
Secondary Investment Objective (Engineering)	Manage the ageing primary transformer fleet and explore refurbishment interventions to achieve life extension and therefore reduce and delay the capital expenditure required to replace the high percentage of the fleet due to reach end of life during the coming years.

Option no.	Options considered	Decision
1	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.	Rejected
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 and oil treatments applied will reduce the deterioration rate and extend their useful life. 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 confidence on this decision is subject to the most sensible parameter, the Refurbishment cost. To adopt this solution, it is important to ensure that the average cost of refurbishments does not exceed the considered for the calculations.	Adopted

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 cape delay offsets the cost of the refurbishment intervention.

<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>

We decided to adopt on-site refurbishments. We will 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 and oil treatments applied will reduce the deterioration rate and extend their useful life. 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 confidence on this decision is subject to the most sensible parameter, the Refurbishment cost. To adopt this solution, it is important to ensure that the average cost of refurbishments does not exceed the considered costs for the calculations.

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.*

A fleet of 85 33/11kV Transformers in poor condition (HI5) has been identified for a possible refurbishment during ED1. They are 63 HI3 and 22 HI4 presenting a very poor external condition which will accelerate the deterioration process 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 improve the units condition to HI3 or HI2 and extend the asset life considerably.

For each of the two options selected for CBA, the predicted fleet Health Index movements during the period have been calculated, according to the Primary Transformers deterioration model. The units will be replaced as soon as possible once they reach HI5. As a result, the replacement cape is distributed very differently along the years on each option resulting in a different effect on the NPV. The Inspection & Maintenance is slightly different in the two options as refurbishment of a unit will avoid I&M cost for that year. Also the failure probability and their related costs, as CI/CML or repair cost, have been calculated according to the fleet condition for each year.

The following were used in our CBA analysis (Baseline above):

Option 2:
On-site refurbishments.

Term (years from first out flow)	NPV (£m)
16	£1.17
24	£1.86
32	£1.83
45	£1.18
first year of investment out flow	1

The following options were not considered in CBA's:

Replacements after failure-To 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.

Early replacements- To 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.

Factory refurbishments- To 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.

Sensitivities

Sensitivity 2.1:
37% higher Refurbishment cost. NPV in year 45 becomes negative when the parameter is a 37% higher. Therefore, this parameter is identified as sensitive and ensuring during tendering that the average "Refurbishment cost" is the assumed is an important factor to adopt this solution.

Term (years from first out flow)	NPV (£m)
16	£0.44
24	£0.93
32	£0.78
45	-£0.00
first year of investment out flow	1

Sensitivity 2.2:

2-fold higher I&M cost. NPV in year 45 does not vary significantly for a 2-fold increase in the parameter. This is due to the fact that the inspections & maintenance activities cost have a small effect compared to other parameters.

Term (years from first out flow)	NPV (£m)
16	£1.04
24	£1.64
32	£1.53
45	£0.75
first year of investment out flow	1

Sensitivity 2.3:

54% higher failure probability in the refurbishment scenario than in the baseline scenario. NPV in year 45 becomes negative when the parameter is a 54% higher than in the baseline scenario. Therefore, even a high deviation from the assumption in Option 2 would not change the decision taken.

Term (years from first out flow)	NPV (£m)
16	£0.59
24	£1.07
32	£0.87
45	-£0.01
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.
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.
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.
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.

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	On-site refurbishments	Adopted	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 confidence on this decision is subject to the most sensible parameter, the Refurbishment cost. To adopt this solution, it is important to ensure that the average cost of refurbishments does not exceed the considered for the calculations.	Network Investment Core Costs	£1.17	£1.86	£1.83	£1.18	
2.1	Sensitivity: 37% higher Refurbishment cost		NPV in year 45 becomes negative when the parameter is a 37% higher. Therefore, this parameter is identified as sensitive and ensuring during tendering that the average "Refurbishment cost" is the assumed is an important factor to adopt this solution.		£0.44	£0.93	£0.78	-£0.00	
2.2	Sensitivity: 2-fold increase I&M cost		NPV in year 45 does not vary significantly for a 2-fold increase in the parameter. This is due to the fact that the inspections & maintenance cost have an small effect compared to other parameters.		£1.04	£1.64	£1.53	£0.75	
2.3	Sensitivity: 40% higher failure probability in the refurbishment scenario than in the baseline scenario.		NPV in year 45 becomes negative when the parameter is a 54% 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	£1.07	£0.87	-£0.01	

Investment Business Case

CBA No	14
Scheme/Project Name	11kV Pilots
Scheme/Project Owner	Patrick 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- Reactive Investment - Repair (on discovery)	Rejected
2	Do Nothing – Make no investment on the HV Pilot asset base	Rejected – Scenario included to show impact on no investment in asset base
3	Proactive Scenario – Condition assessment, Increased Discovery Rates and Investment	Adopted
4	Monitoring Scenario – Proactive Installation of Basic Monitoring systems, Increased Discovery Rates and Investment	Rejected – There is some merit in the approach but its deployment would be best targeted at selected high population sites rather than across all sites on the network as shown in the model.

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.

Pilot cables are aging assets which are degrading, most of which have been installed when the power system was established. 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 the 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, 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 which might have a better NPV if considered over a longer term. SP may fund condition monitoring over time at targeted locations but not in all areas as modelled in Option 4.

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 demonstrated by HV fault performance of Mersey Region as the HV network is mainly of this type.
2. As the fault performance of network completely dependent 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 interruptions fault would result from the removal of all pilots, based on current fault rates.
4. The average customer interruption 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. 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.

7. 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.
8. Annual Impact applied over 45 years.

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 1.13% of the population per annum for all options and assumed that 0.23% of pilots will remain uncleared (with faults) per annum under this scenario.

Option 2: Do Nothing Approach

Financial / Customer impact of no investment - Included for comparison. We have assumed a 1.13% failure rate for this option (as per the note above and other options) and that all failures will remain uncleared as no investment is made to restore condition.

Term (years from first out flow)	NPV (£m)
16	-£11.95
24	-£19.14
32	-£27.58
45	-£34.68
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 1.13% failure rate for this option (as per other options) and that with proactive investment 0.07% of pilots assets will remain faulted annually. This has been assumed only a percentage of the pilot asset base can be tested in any year.

Term (years from first out flow)	NPV (£m)
16	£0.81
24	£1.75
32	£2.87
45	£5.01
first year of investment out flow	1

Option 4: Monitoring Scenario

We have assumed a 1.13% failure rate for this option (as per other options) and that initially 0.07% of pilots asset will remain faulted after each annual investment. As condition monitoring helps manage the asset base we have assumed rate of unrepaired pilot faults will drop to 0.02% annually. Our Business plan includes Option 3. SP may fund the basic monitoring outlined in option 4 but in targeted at selected sites rather that all sites as per the option modelled.

Term (years from first out flow)	NPV (£m)
16	£0.01
24	£0.87
32	£2.10
45	£4.69
first year of investment out flow	1

<u>Sensitivities</u>

<u>Sensitivity 3.1</u>

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

Term (years from first out flow)	NPV (£m)
16	£0.81
24	£1.75
32	£2.87
45	£5.01
first year of investment out flow	1

<u>Sensitivity 3.2</u>

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	£0.36
24	£0.87
32	£1.50
45	£2.74
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Attach CBA spreadsheet here =➔

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 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 @ £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 licence conditions

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	Financial / Customer impact of base level of investment						
2	Do Nothing	Rejected	Financial / Customer impact of no investment - Included for comparion		-£11.95	-£19.14	-£27.58	-£34.68	
3	Proactive Scenario	Adopted	Proactive testing and repair of degraded assets (inc short section replacements)		£0.81	£1.75	£2.87	£5.01	
3.1	Sensitivity to degradation and repair rates		10% increase in pilot failures per annum		£0.81	£1.75	£2.87	£5.01	
3.2	Sensitivity to degradation and repair rates and reduced repair rates		10% increase in failures plus 5% reduction in repair rates		£0.36	£0.87	£1.50	£2.74	
4	Monitoring Scenario	Rejected	SP Business plan includes Option 3 There is also merit in Option 4. SP may as a result elect to install monitoring equipment in highlty populated areas to reduce CI/CML		£0.01	£0.87	£2.10	£4.69	

Investment Business Case

CBA No.	15
Scheme/Project Name	Strategic investment in the electricity distribution system in Shropshire in order to increase supply security and facilitate economic growth of the local area (Whitchurch)
Scheme/Project Owner	Malcolm Bebbington
Primary Investment Objective	To maintain the security of supply
Secondary Investment Objective (Engineering)	Facilitate economic growth in the region

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

Background & Justification

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.

Business as Usual Option (Baseline/Option 1)

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 dependent on a previously authorised project to install a 132kV circuit between Legacy and Oswestry and is currently awaiting the outcome of a public enquiry. 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 programme as the Wem 33kV switchboard will be replaced as part of the works. The baseline scenario has provided the best NPV and we have therefore decided to utilise this scenario.

Chosen Option *(Includes engineering justification if not choosing the highest NPV)*
Both the Baseline Scenario (Option 1) and Option 2 have similar environmental, social and economic impacts in terms of the overall system. The Baseline Scenario has been adopted as internal stakeholder engagement that has also indicated it is the preferred operational arrangement and this also returns 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.*

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 the '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 licence 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 an 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.

Option 2:

Within Option 2, we propose to install an 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 programme. 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	-£1.51
24	-£2.26
32	-£2.77
45	-£3.29
first year of investment out flow	1

Option 3:

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, which may present operational issues, with increased risk of cascade tripping for system faults and reduction in 33kV fault level headroom in the adjacent groups.

Term (years from first out flow)	NPV (£m)
16	-£0.44
24	-£0.82
32	-£1.08
45	-£1.35
first year of investment out flow	1

Sensitivities

Sensitivity 2.1:

We performed a sensitivity analysis on Option 2 to make sure that this may not become more favourable than the baseline. We imposed a 5% reduction in investment costs on Option 2. The Baseline Scenario has been adopted as internal stakeholder engagement that has also indicated it is the preferred operational arrangement.

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Option 1 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 enquiry. 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 2 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 3 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	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	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	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	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
1 (Baseline)	To establish a 132kV Grid in-feed at Wem substation.	Adopted	Both the Baseline Scenario (Option 1) and Option 2 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.						
2	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.		-£1.51	-£2.26	-£2.77	-£3.29	
3	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.		-£0.44	-£0.82	-£1.08	-£1.35	

Investment Business Case

CBA No.	16
Scheme/Project Name	Pole Replacement
Scheme/Project Owner	Dave Kilday
Primary Investment Objective	To determine the optimum method of replacing HI5 wood poles.
Secondary Investment Objective (Engineering)	Replace as many H15 poles whilst returning the best NPV

Option no.	**Options considered**	**Decision**
1	Baseline scenario: replace the decayed poles under an outage.	Rejected
2	Replace the decayed poles using Rubber Glove 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

Poles are crucial aspects of our network and, due to an ageing network, a large proportion of these are near their end of life. While end of life poles will be replaced in circuits that are being refurbished, as part of our storm resilience philosophy, we will also replace end of life poles on circuits that are not being refurbished in RIIO-ED1.

Every time we assess the poles we can either replace the poles under an outage or we can replace the poles using live techniques. This will have various impacts as the level of highly skilled staff involved in live replacement will be much greater than that of outage replacement. The time it takes to replace the poles will also vary with each option.

Business as Usual Option (Baseline/Option 1)

Our business as usual option is simply to replace the decayed poles under an outage.

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

We have chosen Option 2; to replace the decayed poles using live line techniques. This returns the highest NPV by a considerable amount. Although using live techniques sounds dangerous, this is in fact very safe as only highly trained and skilled individuals would be allowed to undertake such work.

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 must decide whether it is more viable to replace the decayed poles under an outage; Replace the decayed poles using live line techniques or replace the decayed poles under an outage but install generators to prevent customers from going off supply.

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. It has been assumed that a Rubber Glove Live Line team will replace 2 poles per day, assuming that a separate group of contractors will need to erect the new pole through the live conductors using live working techniques.

Option 2:

Using this option we will be able to replace the same volume of poles whilst returning a better NPV. Within this CBA we have assumed that a Rubber Glove Live Line team are able to change 2 poles per day.

Term (years from first out flow)	NPV (£m)
16	£6.58
24	£7.41
32	£7.95
45	£8.50
first year of investment out flow	1

Option 3

The following assumptions have been made to obtain our final figures:

- It is assumed that a contracting squad will be able to replace 6 H15 poles during a 5 hour outage.
- an average outage will switch of supply to the same number of customers as a typical overhead line fault, 143 customers
- CLM per outage is 42900
- A total of 9,200 poles will be replaced as part of a pole replacement programme
- Per annum, a total of 1,150 poles will be replaced as part of a pole replacement programme
- No of customer outages per annum is 191.67
- Number of generators required for a typical job is 5

Term (years from first out flow)	NPV (£m)
16	-£1.36
24	-£2.59
32	-£3.40
45	-£4.22
first year of investment out flow	1

Sensitivities

N/A

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 indevidual 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.		£6.58	£7.41	£7.95	£8.50	
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.		-£1.36	-£2.59	-£3.40	-£4.22	

Investment Business Case

CBA No.	17
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.	Accepted
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	£1.85
24	£2.20
32	£2.42
45	£2.64
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	-£0.39
24	-£0.73
32	-£0.93
45	-£1.14
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.

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	Although there is a financial advantage to allowing the service cables to fail, 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.		£0.00	£0.00	£0.00	£0.00	
2	Replace HI5 poor condition cut-outs only.	Rejected	Although there is a financial advantage to allowing the service cables to fail, 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.		£1.85	£2.20	£2.42	£2.64	
3	Upgrade HI5 poor condition cut-outs and service cables	Rejected	This option spends too much money upgrading assets that do not require to be upgraded.		-£0.39	-£0.73	-£0.93	-£1.14	

Investment Business Case

CBA No.	18
Scheme/Project Name	Langside Reinforcement Utilising Active Network Management
Scheme/Project Owner	Alan Collinson
Primary Investment Objective	Support load growth in the local area
Secondary Investment Objective (Engineering)	Utilise a smart grid solution active network management to alleviate the forecast demand at Langside.

Option no.	Options considered	Decision
1	Baseline- To install a new 33/11 kV transformer to resolve capacity issue in Langside primary substation.	Rejected
2	To install the smart grid solution active network management – dynamic network reconfiguration (ANM-DNR) in Langside.	Accepted

Background & Justification

The maximum demand at Langside has, for a number of years, hovered around the substation 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. Regarding the anticipated load growth in the area) including SP Best View Scenario for capacity based on WS3 analysis) the demand on Langside will exceed the firm capacity of 21MVA within the period of ED1. The traditional solution of uprating the transformers of the overloaded substation is not considered as this solution is focussed at sites where the transformers are less than 12/24MVA units and Langside already has 21MVA units installed. The installation of a new 24MVA transformer would seem excessive to the amount of load growth which could be envisaged in the future. A secondary consideration would be the availability of land which could site a new primary substation in a mature urban environment. It is therefore proposed that an automation system is developed, which allows demand to be transferred to adjacent primary substations when the demand at Langside exceeds the firm capacity of the site. This could be applied by automating the normally open points to allow transfers to be undertaken remotely by the Operational Control Centre. This will defer the creation of a new injection point a considerable number of years.

Business as Usual Option (Baseline/Option 1)

Baseline scenario is the conventional solution based on the current reinforcement strategy with the installation of a new 33/11 kV transformer to resolve load issue in Langside primary substation.

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

The installation of the smart grid solution active network management – dynamic network reconfiguration would involve automation of strategic points on the 11 kV network to allow approximately 4MVA of demand transfers to be carried out remotely to adjacent sites and pick up demand from Langside. Therefore the installation of the reinforcement transformer can be deferred. The life expectancy of this solution is 20 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.*

We have made the following assumptions:

Proposed year for investment	2020
Defer investment by (years)	10

Option 2:
Is to install the smart grid solution active network management – dynamic network reconfiguration to alleviate the forecast demand at Langside. By utilising the Smart grid solution option: active network management - dynamic network reconfiguration (ANM-DNR) we have achieved the following NPV.

Term (years from first out flow)	NPV (£m)
16	£0.96
24	£0.61
32	£0.33
45	£0.03
first year of investment out flow	5

Sensitivities

N/A

Appendix 1: Cost Benefit Analysis

Attach CBA spreadsheet here =➔

Options considered	Comment
Option 1- Baseline scenario is the conventional solution based on the current reinforcement strategy with the installation of a new 33/11 kV transformer to resolve load issue in Langside	The Baseline Scenario identified is to equip the group with a new injection point and the additional creation of 24MVA of capacity in the area.
Option 2- is to install the smart grid solution active network management – dynamic network reconfiguration to alleviate the forecast demand at Langside.	The installation of the smart grid solution active network management – dynamic network reconfiguration would involve automation of strategic points on the 11 kV network to allow approximately 4MVA of demand transfers to be carried out remotely to adjacent sites and pick up demand from Langside. Therefore the installation of the reinforcement transformer can be deferred. The life expectancy of this solution is 20 years according to the SGF-WS3.

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)	To install a new 33/11 kV transformer to resolve capacity issue in Langside primary substation.	Rejected	The conventional reinforcement would be excessive to the amount of load growth which could be envisaged in the future. Moreover the availability of land for a new primary substation would be limited in a mature urban area.		£0.00	£0.00	£0.00	£0.00	
2	To install the smart grid solution active network management – dynamic network reconfiguration (ANM-DNR) in Langside.	Adopted	It is proposed to consider this smart solution.		£0.96	£0.61	£0.33	£0.03	

Investment Business Case

CBA No.	19
Scheme/Project Name	Crewe 132kV asset replacement
Scheme/Project Owner	Peter Sherwood
Primary Investment Objective	To reduce the risk from the end of life assets
Secondary Investment Objective (Engineering)	Replace HI5 assets

Option no.	**Options considered**	**Decision**
1	AIS switchgear solution and replacement of grid transformer (base).	Rejected
2	GIS switchgear solution and replacement of grid transformer	Rejected
3	GIS switchgear solution, replacement of grid transformer and 132kV oil filled cable	Adopted

Background & Justification

Crewe substation is a key node on the 132kV network supporting a major part of Cheshire. The 132kV switchgear was manufactured and installed in 1966. The thirteen circuit breakers in situ are, AEI/Metropolitan Vickers OW410 bulk oil circuit breakers, and are deemed to be end of life.

The switchgear needs replaced and the solutions are either an outdoor air insulated busbar solution or an indoor gas insulated busbar solution. Both these solutions have been costed. In addition, the replacement of the on-site 132kV oil filled cable was considered as being replaced along with the GIS solution (option 3) and has also been assumed would required to be replaced in options 1 and 2 10 years later.

Business as Usual Option (Baseline/Option 1)

Replace Switchgear with AIS solution & GT in situ and 132kV oil filled cables 10 years later in ED2.

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

Replace Switchgear with GIS Solution & GT and oil 132kV oil filled cable.

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 1 (baseline)
An AIS solution for the switchgear and replacement of the 132kV oil filled cable 10 years hence. The costs also include the replacement of a 132kV grid transformer. This option would require extended system outages to complete and switchgear life would less than that for options 2 & 3.

Option 2
A GIS solution for the switchgear and replacement of the 132kV oil filled cable 10 years hence. The costs also include the replacement of a 132kV grid transformer. Marginally reduced NPV but provides a solution with expected longer life than the base.

Term (years from first out flow)	NPV (£m)
16	-£0.19
24	-£0.14
32	-£0.10
45	-£0.05
first year of investment out flow	2

Option 3
A GIS solution for the switchgear and replacement of the 132kV oil filled cable. The costs also include the replacement of a 132kV grid transformer. The reduced NPV at the beginning is due to the addition of the 132kV cable. However this allows for future reinforcement at initial minimal additional cost and the NPV improves later on.

Term (years from first out flow)	NPV (£m)
16	**-£0.41**
24	**-£0.25**
32	**-£0.13**
45	**£0.01**
first year of investment out flow	2

Appendix 1: Cost Benefit Analysis

Attach CBA spreadsheet here =➔

Options considered	Comment
AIS Swgr. Solution (base)	Replace Swgr with AIS solution & GT in situ and 132kV oil filled cables 10 years later in ED2
GIS Solution	Replace Swgr with GIS Solution & GT and oil 132kV oil filled cable 10 years later in ED2
GIS Solution and 132kV oil filled cable	Replace Swgr with GIS Solution & GT and oil 132kV oil filled cable

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	AIS Swgr. Solution (base)	Rejected	Would require extended system outages to complete and reduced life		£0.00	£0.00	£0.00	£0.00	
2	GIS Solution	Rejected	Marginally reduced NPV but provides a solution with expected longer life than the base		-£0.19	-£0.14	-£0.10	-£0.05	
3	GIS Solution and replacement of 132kV oil filled cable	Adopted	The reduced NPV at the beginning is due to the addition of the 132kV cable. However this allows for future reinforcement at initial minimal additional cost and the NPV improves later on.		-£0.41	-£0.25	-£0.13	£0.01	

Investment Business Case

CBA No	20
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 us, through customer minutes lost (CML) and customer interruptions (CI) penalties. In addition to CI/CML penalties, the fault repair cost must be incurred by us 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 particular 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	-£2.61
24	-£3.28
32	-£3.73
45	-£4.18
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	-£132.36
24	-£166.51
32	-£188.02
45	-£206.09
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	-£27.08
24	-£34.07
32	-£38.49
45	-£42.26
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 increased cost		-£2.61	-£3.28	-£3.73	-£4.18	
3	Underground Cable (185 waveform)	Rejected	Rejected due to increased cost		-£132.36	-£166.51	-£188.02	-£206.09	
4	Underground - Combination of Increased conductor size and U/G cable	Rejected	Rejected due to increased cost		-£27.08	-£34.07	-£38.49	-£42.26	

Investment Business Case

CBA No.	21
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 purpose 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, we will install 100mm² AAAC “Oak” conductor and where it is being installed in a normal weather area we will 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 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

Option 2
Uprate 100% of normal weather rebuild to 100mm² AAAC “Oak” conductor

Term (years from first out flow)	NPV (£m)
16	£0.06
24	£0.27
32	£0.45
45	£0.74
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	£0.03
24	£0.13
32	£0.23
45	£0.37
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Option 1 Baseline Scenario- (Existing Asset Replacement Policy)	Separate asset replacement and reinforcement programmes (BAU approach)
Option 2 - 100% of normal weather area	
Option 3 - 50% of normal weather area	
Option 4 - Future Proofing 11kV OHL Main Lines and Spur Lines	As Option 2 but includes spur line replacement as well - not considered as it would be prohibitively expensive

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			£0.06	£0.27	£0.45	£0.74	
3	50% of normal weather rebuild to 100mm² AAAC conductor	Rejected			£0.03	£0.13	£0.23	£0.37	

Investment Business Case

CBA No.	22
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 50mm² AAAC conductor	Rejected
2	Uprate 100% of normal weather rebuild to 100mm² AAAC conductor	Adopted
3	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 purpose 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, we will install 100mm² AAAC "Oak" conductor and where it is being installed in a normal weather area we will 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" conductors 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 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	**£0.08**
24	**£0.28**
32	**£0.46**
45	**£0.73**
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	**£0.04**
24	**£0.14**
32	**£0.23**
45	**£0.36**
first year of investment out flow	1

Appendix 1: Cost Benefit Analysis

Options considered	Comment
Option 1 Baseline Scenario- (Existing Asset Replacement Policy)	Separate asset replacement and reinforcement programmes (BAU approach)
Option 2 - 100% of normal weather area	
Option 3 - 50% of normal weather area	
Option 4 - Future Proofing 11kV OHL Main Lines and Spur Lines	As Option 2 but includes spur line replacement as well - not considered as it would be prohibitively expensive

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			£0.00	£0.00	£0.00	£0.00	
2	100% of normal weather rebuild to 100mm² AAAC conductor	Adopted			£0.08	£0.28	£0.46	£0.73	
3	50% of normal weather rebuild to 100mm² AAAC conductor	Rejected			£0.04	£0.14	£0.23	£0.36	

Project REF	Project	Primary Investment Objective	Secondary Investment (Engineering) Objective	Baseline Option	Adopted Option	NPV £m (compared to baseline) (Over 45 years
1	HV Transformer Replacement (SPD)	To reduce the SPD company's carbon footprint	To replace our inefficient/ High Loss 11kV transformers	Replace HV distribution transformers driven by ED1 RMU programme only	Work on top of the baseline and target high loss units (pre 1962) out with RMU programme based on load	1.55
2	HV Transformer Replacement (SPM)	To reduce the SPD company's carbon footprint	To replace our inefficient/ High Loss 11kV transformers	Replace HV distribution transformers driven by ED1 RMU programme only	Work on top of the baseline and target high loss units (pre 1962) out with RMU programme based on load	0.55
3	11kV Circuit Breakers	To manage deteriorating 11kV CBs	A cost effective engineering balance in relation to retrofitting, replacement and refurbishment solutions.	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.	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	6.42
4	Black Start resilience	To meet our obligation and our stakeholder expectations.	To validate the planned approach to be taken by SPEN in achieving the required level of resilience	Baseline case is based on installing a standby generator at all Grid & Primary sites, that have a 'significant' AC or DC requirement.	We have chosen to utilise 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	49.03
5	Boron Treatment of Wooden Poles	Improve the reliability of an increasingly ageing network	To determine whether to replace or treat HI4 decayed wood poles with Boron.	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.	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	0
6	Smart Solutions in the reinforcement of the Chester 33kV group	To defer the replacement of RMUs in order to provide a cost saving to the customer whilst maintaining a secure supply	Replacement of RMUs at or above fault break rating	To replace all seven RMUs which are close to or above their fault break rating. Of these, five would be above rating. However, the other two outdoor breakers are potentially below rating during lower fault level periods	It is proposed to replace five of the seven RMUs that are not currently part of the asset replacement programme during the ED1 period. The remaining fault level issue will be managed by using the newly developed fault level monitor to assess the real- time fault levels at the Huntington 33kV busbar	0.19
7	Crewe Reinforcement- Utilising Phase shifting transformer	The installation of smart grid solutions may save building a new distribution line.	Establishing a new 132 kV circuit in order to support demand growth and secure the group.	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.	Our final chosen Option is to install a 132kV Phase Shift Transformer (PST) at Crewe Grid to couple the Cellarhead GSP and Fiddlers Ferry/Carrington GSP Groups	11.95
8	Mural Wiring	Public Safety	Determine optimal solution for the modernisation of poor performing urban mural wiring	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.	Renewing the mural wiring on a "like for like" basis every 25 years, where technically feasible. This provides the best NPV.	13.3
9	Pole Mounted Transformers	To optimise the replacement or refurbishment of pole mounted transformers while carrying out overhead line rebuild and refurbishment works	To replace HI4 and HI5 pole mounted transformers.	Our business as usual method is to replace the pole mounted transformers with new transformers when off-line rebuilding overhead lines	Replace the pole mounted transformers with refurbished transformers	2.08

10	Real Time Thermal Rating (RTTR) Transformer	Reach an additional capacity on our network and therefore the installation of reinforcement transformers can be deferred.	Engage with Smart Grid Solutions to assist in the identification and appraisal of alternative network investments.	Conventional solution: current reinforcement strategy with the installation of new 33/11 kV transformers to resolve thermal capacity issue in primary substations.	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	0.45
11	Replace end of life RTUs	Replace end of life RTUs	Sustainable control with functionality required for future network requirements	Installation of a new RTU solution bespokely engineered to support Legacy Protocols and Data Models	Installation of RTU solution based on industry standard protocol support international standards for substation automation - Extended timescales - for population replacement	8.96 (Please see CBA)
12	33kV Transformer Refurbishments SPD	Guarantee the reliability of the network with smart and effective investment alternatives	Manage the ageing primary transformer fleet and explore refurbishment interventions to achieve life extension and therefore reduce and delay the capital expenditure required to replace the high percentage of the fleet due to reach end of life during the coming years	Continue with routine maintenance & inspections. Do not carry out refurbisment to extend life and replace transformers when they reach end of life.	To carry out on-site refurbishments	3.01
13	33kV Transformer Refurbishments SPM	Guarantee the reliability of the network with smart and effective investment alternatives	Manage the ageing primary transformer fleet and explore refurbishment interventions to achieve life extension and therefore reduce and delay the capital expenditure required to replace the high percentage of the fleet due to reach end of life during the coming years	Continue with routine maintenance & inspections. Do not carry out refurbisment to extend life and replace transformers when they reach end of life.	To carry out on-site refurbishments	1.18
14	11kV Pilots	Maintain current frontier levels of customer service and safety in urban areas against aging asset base	To replace End of Life & Poorly Performing UG Protection Pilots (HV)	Our Baseline/ Business as usual is Reactive Investment. (We repair upon discovery).	To utilise proactive testing and repair degraded assets (inc short section replacements)	5.01
15	Whitchurch reinforcement - Strategic investment in the electricity distribution system in Shropshire	To maintain the security of supply	Facilitate economic growth in the region	The Baseline Scenario is to install a Grid Transformer at Wem substation and a 132kV circuit from Oswestry Grid.	The Baseline Scenario has been adopted as internal stakeholder engagement that has also indicated it is the preferred operational arrangement and this also returns the best NPV	0
16	Pole Replacement	To determine the optimum method of replacing HI5 wood poles	Replace as many H15 poles whilst returning the best NPV	Our business as usual option is simply to replace the decayed poles under an outage.	We have chosen to replace the decayed poles using live line techniques	8.5
17	Service Position Modernisation	To optimise the replacement cut-outs and service cables in light of future increasing load.	Replace HI5 cut-outs and service cables.	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.	We have adopted our baseline strategy	0
18	Langside Reinforcement Utilising Active Network Management	Support load growth in the local area	Utilise a smart grid solution active network management to alleviate the forecast demand at Langside	Baseline scenario is the conventional solution based on the current reinforcement strategy with the installation of a new 33/11 kV transformer to resolve load issue in Langside primary substation	The installation of the smart grid solution active network management – dynamic network reconfiguration would involve automation of strategic points on the 11 kV network to allow approximately 4MVA of demand transfers to be carried out remotely to adjacent sites and pick up demand from Langside	0.03

19	Crewe 132kV asset replacement	To reduce the risk from the end of life assets	Replace HI5 assets	Replace Switchgear with AIS solution & GT in situ and 132kV oil filled cables 10 years later in ED2	Replace Switchgear with GIS Solution & GT and oil 132kV oil filled cable	0.01
20	LV OHL Village Modernisation	To replace ageing LV network in Villages and improve fault performance for customers	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)	Our baseline scenario is to use 92% overhead line and 8% of underground cable	We have adopted our baseline scenario as this will return the best NPV by a considerable amount	0
21	OHL Rebuild SPD	To ensure a fit for purpose OHL network	To build to a cost optimal design specification	Our baseline option (Option 1) where where the line is being rebuilt in a normal weather area we will install 50mm² AAAC "Hazel" conductor.	The Option which returns the best NPV is 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.	0.74
22	OHL Rebuild SPM	To ensure a fit for purpose OHL network	To build to a cost optimal design specification	Our baseline option (Option 1) where where the line is being rebuilt in a normal weather area we will install 50mm² AAAC "Hazel" conductor.	The Option which returns the best NPV is 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.	0.73