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DPCR4 – FBPQ ANALYSIS AND CAPEX PROJECTIONS

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LIST OF REVISIONS

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Final	28/06/04	All	Adjustment following submission of final capital expenditure numbers.			
Final	28/10/04	All	Revision of model and allowance levels following DNO meetings with Ofgem and Ofgem September paper.			

CONTENTS

LIST OF ABBREVIATIONS

Capex	Capital expenditure
CBRM	Condition Based Risk Management
CHL	Customer hours lost
CI	Customer interruptions per 100 customers
CML	Customer minutes lost per connected customer
Consac	A type of concentric LV mains cable
DNO	Distribution Network Operator
DPCR	Distribution Price Control Review
DTI	Department of Trade and Industry
EATS	Electricity Association Technical Specification
EHV	Extra High Voltage (i.e. > 22kV)
ESQCR	Electricity Safety, Quality and Continuity Regulations 2002
FBPQ	Forecast Business Plan Questionnaire
GDP	Gross Domestic Product
GVA	Gross Value Added
GWh	Gigawatthour (a unit of energy)
HBPQ	Historic Business Plan Questionnaire
HV	High Voltage (i.e. between 1kV and 22kV)
km	kilometre
kV	kilovolt
LV	Low voltage (i.e. less than 1kV and here 230/400V)
m	Million
MEAV	Modern Equivalent Asset Value
MPRS	Meter Point Registration System
OHL	Overhead line
PB	Parsons Brinckerhoff
UUE	United Utilities (Electricity)
QoS	Quality of supply (reliability/interruption performance)
SSAP	Standard accountancy practice

FOREWORD

This report sets out the views of PB Power on the capital expenditure in the DNO's FBPQ submission to Ofgem for DPCR4. It supersedes the earlier (June 2004) report and changes reflect the outcome of the meeting with the DNO in August 2004.

The comments in the report are based on the information provided by the DNO concerned as part of the FBPQ submission to Ofgem, subsequent meetings and information exchanges between Ofgem, ourselves and all the DNOs. The volume of information submitted in support of the business plans has been substantial in both narrative and numerical form and, together with subsequent meetings and clarifications, has provided an insight to the rational for expenditure variation compared to that in DPCR3.

We have however reviewed the expenditure and drivers of the DPCR4 Base Case Scenario only, with a limited overview of the Ofgem Scenario/Sensitivity and the DNO Alternative Case. In particular, we have taken note that Ofgem's requirement that capital expenditure included in the Base Case Scenario should be only that necessary to maintain the distribution system at its existing performance level in respect of quality of supply. It follows in our view that the level of network risk experienced during DPCR3 should also be held constant during the forthcoming review period. Where DNOs have included expenditure that may not fit with those objectives then such expenditure is not deemed to be appropriate to the Base Case Scenario and has therefore been excluded from our considerations, except as part of the process of identifying such expenditure. This approach does not imply that we do not believe that the non-Base Case expenditure identified is inappropriate or unjustified; in fact in some instances we have observed that non-Base Case expenditure may be prudent. This approach of limiting consideration to only the Base Case Scenario seeks to ensure that all DNOs are considered on an equitable basis with any further consideration as to treatment of special cases resting between Ofgem and the DNO concerned.

Our approach to the modelling of both load-related and non-load related expenditure has been developed on principles agreed by Ofgem and discussed with the DNOs. The models have been populated with data submitted to Ofgem by the DNOs. The output from the models therefore reflects the input data comprising individual DNO data, practices and from these aggregate DNO data which has been used to create 'industry-level' data. The principle that has been applied is that the output of the models should reflect a general industry view against which each DNO's submission can be compared. In respect of the modelling of non-load related expenditure, no material age dispersion across DNOs has been observed for the main asset classes. Consequently any major difference between DNO submission and model output is likely to reflect a difference with general industry practice in terms of replacement or refurbishment policy and unit costs. Information provided by a DNO has been assumed to be correct although concerns on unsupported changes to the asset age profiles of certain DNOs have been raised with Ofgem.In forming a "PB Power" opinion of the proposed allowance, we have observed the approach set out above. Our modelling has been used as a guide and, where expenditure differing from that indicated by the model has been justified and is in keeping with Base Case Scenario, we have duly taken account of such differences.

We would also like to take the opportunity of expressing our appreciation of the time taken and courtesy extended by the staffs of Ofgem and the DNOs during meetings and in responding to our queries.

EXECUTIVE SUMMARY

The following table summarises UUE's adjusted DPCR3 projection, adjusted DPCR4 forecast, PB Power's modelling results and opinion of proposed expenditure.

Expenditure Category	**Adjusted DPCR3 Projection (£m)**	**Adjusted DPCR4 Forecast (£m)**	**Model Output (£m)**	**PB Power Opinion (£m)**	**PB Power Comments**
Load Related Expenditure - Gross	172.6	237.1	212.5	221.0	The model was run with the DNO proposed DPCR4 LRE; no uplift for competition in connections was undertaken. The units and customer numbers have been smoothed in accordance with the description on LRE modelling. The output from the model has been taken as a fair reflection of the LRE needs of the company based on long-run investment.
Customer Contributions	(87.1)	(78.2)		(78.2)	
LRE Net	**85.5**	**159.1**		**142.8**	
Asset Replacement	242.4	284.3	253.6	273.9	The model has constrained the submission primarily due to high forecast expenditure associated with HV and EHV overhead line. The level of forecast cable expenditure, across all voltage tranches, is less than that submitted by UUE. The level of difference between modelled output and submission is in excess of that for overhead line.
Other	146.5	144.4		143.0	£143m comprises diversions (£10.4m), SCADA (£12.1m), metering (£18.7m) and non-fault capex (£101.7m).
NLRE Total	**388.7**	**428.7**		**416.9**	
Non Operational	49.0	32.4		32.4	
DNO Total	**523.2**	**620.2**		**592.0**	
DNO Total				*439.2*	*As Ofgem Sep 04 paper, excl. meters, faults, non operational and ESQCR*

BASE CASE SUBMISSION

PB Power's review is of the Base Case capex forecasts excluding diversions, metering, fault capex and non-operational capex. Fault expenditure is considered separately. Where appropriate the forecasts and DPCR3 projections have been adjusted for the funding of the pension deficit, capitalised overheads, inter-company margins and lane rentals in line with figures provided by the DNOs in their submissions and summarised by Ofgem. Where companies have indicated a loss of new connections market share, PB Power has also made adjustments to gross load related expenditure to reflect the total connections market.

Adjustments have been made to the UUE forecast in respect of pension funding deficit, capitalised overheads and inter company margin.

Our principal findings are summarised below:

Load related expenditure

- The level of Load Related Expenditure is heavily influenced by a number of primary network schemes. The delivery profile of those schemes is early to mid review. This should provide increased certainty with regard to actual delivery. However, certain schemes appear weak in respect of a firm description and hence justification of need.

- The majority of schemes reviewed have yet to go through 'Optioneering'. Therefore phasing, rescoping and pricing changes are possible.

- The level of secondary network 'at risk' is forecast to be £6.6m higher than an unadjusted DPCR3 level. UUE has provided support for this increase. However, further review may be required in order to ensure that there is no betterment in the network in accordance with the Base Case guidance.

- It may be that rescoping and deferral of projects during the period may reduce expenditure by £20m to £30m.

Non-load related expenditure

- In general, secondary network activity is similar to that forecast for DPCR3 but the forecast expenditure is approximately £10m higher.

- The capital forecast for non-fault Consac replacement appears relatively low but an increase in capitalised fault replacement is noted. The appropriate level of capitalised faults will be determined elsewhere.

- Comments made above with regard to site-specific load related expenditure also apply to non-load replacement and again deferral and rescoping may reduce expenditure by £10m to £15m.

- The company has identified capital expenditure associated with civil contingencies and vandalism but the justification for this does not appear robust. On the basis of the information presented, the total £4m identified may be high by £2m.

We would also make the following general comments:

- PB Power's non-load related modelling is based on the asset lives provided by DNOs. Subsequent refinements have been made to this modelling to reflect PB Power's view of efficient DNO policies and practice.

- There is some concern about the comparability of data between DNOs due to different policies applied by DNOs, particularly the boundary between fault and non-fault replacement and capitalisation of overheads.

- The data presented in this appendix includes comparisons between DPCR3 allowances, DPCR3 projections and DPCR4 forecasts. Care needs to be taken in reviewing these figures in respect of the following:

    - The DPCR3 allowance included £2.30 per customer per year (1997/98 prices) capex for quality of supply[1], which is not separately identified in the DPCR3 projections and is not included in the Base Case DPCR4 forecast.

Quality of supply scenarios

- The quality of supply submission indicates low level of expenditure with sufficient flexibility in the initiatives proposed to allow scaling up and down to be easily implemented. The impression is that scope for efficient investment on the network in order to deliver measurable customer improvement exists and is within UUE's reach.

DNO alternative case

- The DNO alternative scenario and the Base Case submission are the same with the exception of performance improvement expenditure and the comments above on the Base Case submission are equally applicable to the DNO alternative case.

PB Power view on load-related and non-load related expenditure allowances (Base Case)

Load related expenditure

The UUE forecast is higher than the DPCR3 projection, in terms of both gross expenditure and net of customer contributions. We have commented earlier on the level of justification,

[1] Ofgem DPCR 3 Final Proposals Paper December 1999 para 3.14 page 28

the possibility of phasing, scoping and pricing change and that these factors may reduce expenditure by between £20m and £30m.

The model output indicates that UUE's forecast is high in relation to customer growth. Accordingly we project a level of gross load-related expenditure at £221.5m (£143.7m net) that is about £15m below the forecast.

Non-load related expenditure

The model generates lower overall expenditure than the forecast largely because the model predicts lower expenditure on overhead line replacement, in particular at HV and EHV. For substations the model generates slightly higher expenditure than the UUE forecast and this difference is mainly attributed to transformer related expenditure. For underground cables the model predicts higher expenditure than the forecast and this difference is driven primarily by volume variance in the LV and HV asset classes. We discuss possible reasons for UUE's forecast replacement of LV Consac cables being low.

In PB Power's opinion, the allowed asset replacement expenditure corresponding to the model output should be £273.9m being the adjusted DPCR4 forecast less ESQCR expenditure of£10.4m, this amount excluding ESQCR related expenditure which is being reviewed separately. With the inclusion of diversions, metering and fault capital expenditure the corresponding overall non-load related expenditure would be£416.9m.

Conclusions

The above considerations would indicate that a total capital expenditure, net of customer contributions, of £592.0m would be appropriate.

1. INTRODUCTION

The Office of Gas and Electricity Markets (Ofgem) appointed PB Power to provide support for the 2005 Distribution Price Control Review (DPCR4) covering aspects of capital expenditure and repairs and maintenance forecasting, excluding distributed generation which is covered by a separate review. The project is in two parts.

- Part 1, covered the systems, processes, assumptions, asset risk management and data used by Distribution Network Operators (DNOs) to forecast capital expenditure and an analysis of variances and efficiency gains in the HBPQ period.
- This Part 2 report provides an analysis of forecast expenditure for the five year period to 31 March 2010 and builds on information obtained in Part 1 of the project.

Each DNO was requested to provide forecasts of future capital expenditure requirements against 3 scenarios: the Base Case Scenario; the Ofgem Scenarios/Sensitivities; and the DNO Alternative scenario.

The Base Case is intended to reflect the forecast investment requirement that would maintain existing network quality of supply performance and network fault rates together with the same level of network resilience for the period to 2020.

The Ofgem Scenarios/Sensitivities set out network performance improvement targets for 2010 and 2020 with sensitivities of ± 2% and ± 5% of the 2010 targets. The targets are based on Ofgem's view depending on the nature of each of the DNO networks.

The DNO Alternative Scenario is intended to reflect the DNO view of the efficient level of capital expenditure required to meet the outputs they consider appropriate for their area of supply.

The PB Power review of the DNO forecasts is undertaken as follows:

a. Further questions and visits to companies to inform a review of each DNO capital expenditure forecast to give a bottom up view of the assumptions, risk assessments and justifications put forward by DNOs for their Base Case forecast, and a high level review of the Ofgem and DNO scenarios.

b. For the Base Case load-related expenditure, a benchmarked comparison of the each DNO's forecast with a PB Power forecast using a PB Power model based on the methodology set out in Appendix D.

c. For the Base Case non-load related expenditure, a comparison of the DNO forecast with a PB Power forecast using industry average weighted asset replacement profiles and PB Power's unit costs.

d. From consideration of the above we have formed a "PB Power Opinion" of the proposed allowance.

As indicated above Ofgem provided criteria for the Base Case forecasts. The DNOs' forecasts are based on different assumptions included in the DNO FBPQ submissions. As instructed by Ofgem, adjustments have been made to the DNO forecasts to take account of differing treatments of pension funding deficits, capitalised overheads, intercompany margins and lane rentals. Where appropriate the load-related expenditure, as submitted has been grossed up to take the cost of all connections into account including where these may have been provided by third parties.

In our review of asset replacement expenditure, only non-fault expenditure has been considered. Other items in non-load related expenditure namely diversions, SCADA, metering and fault capital expenditure have been treated as a pass-through. No assessment has been made of non-operational capital expenditure.

Adjustments to DPCR4 forecast. In the FPBQ submissions, allowances may have been made by DNOs for items including third party connections, pension funding deficit, capitalised overheads, inter-company margins and lane rentals. In order to bring the forecasts of capital expenditure onto a common basis, Ofgem has been in discussion with all DNOs as to the level of those adjustments and has arrived at an "Adjusted DPCR4 Forecast" as is indicated in tables in the report.

2. DNO SUBMISSION

2.1 Base case

2.1.1 General

UUE's approach to forecasting the Capex projections has been to define the volume of activity associated with non-load replacement based on maintaining a constant fault rate consistent with Ofgem's Base Case directions.

The capex in the Base Case submission makes no additional expenditure allowance for quality of supply or resilience. UUE has included capital expenditure necessary to deal with ESQCR issues. UUE has also included within the Base Case provision for additional pension cost. No allowance for lane rental has been included in either load or non-load related expenditure. UUE has made no allowance for loss of market share of the connections market. It has made provision for a substantial reduction in the meter operator business and as a consequence the level of non-load related metering expenditure is significantly reduced.

The following table presents the revised DPCR4 forecast expenditure together with the corresponding DPCR3 allowance and projection.

Table 2.1 - Base Case Capex Projections (£m at 2003/03 prices)

Item	DPCR3 Allowance	Adjusted DPCR 3 Projection	DPCR 4 Forecast	DPCR4 Corrections	Revised DPCR4 Forecast
Gross Load Related	**180.7**	**172.6**	**240**	**0.0**	**240.0**
Non Load Related	**364.8**	**388.7**	**437**	**0.0**	**437.0**
Gross Capex less Non Op Capex	***545.5***	***561.3***	***677***	***0.0***	***677.0***
Non Op Capex (Not Assessed)	16.8	**49**	32.4	0.0	32.4
Total Gross Capex	**562.3**	**610.3**	**709.4**	**0.0**	**709.4**
Contributions	-53.7	87.1	-79.1	0.0	-79.1
Net Load Related	**127.1**	**85.5**	**160.9**	**0.0**	**160.9**
Total Net Capex	**508.6**	**523.2**	**630.3**	**0.0**	**630.3**
Non Load Related Summary					
Replacement	319		259.7	0.0	259.7
ESQCR			10.5	0.0	10.5
Heath & Safety			0.9	0.0	0.9
Environment			16.4	0.0	16.4
Sub Total - Model Comparison	**319**	**242.4**	**287.5**	***0.0***	***287.5***
Diversions	16.7	9.7	12	0.0	12.0
SCADA		9.7	12.2	0.0	12.2
Sub Total	***335.8***	***261.8***	***311.8***	***0.0***	***311.8***
Metering (Not Assessed)	29	44	18.9	0.0	18.9
Sub Total	***364.8***	***305.8***	***330.7***	***0.0***	***330.7***
Fault Capex (Not Assessed)		82.8	106.4	0.0	106.4
Non Load Related Total	**364.8**	**388.7**	**437.0**	**0.0**	**437.0**

The forecast has been adjusted for:

- gross market LRE adjustment, to take account of customer connection expenditure by third parties
- pension funding deficit
- capitalised overheads
- inter-company margin and
- lane rentals.

The adjusted DPCR4 forecast is presented in the table below.

Table 2.2 – Adjusted DPCR4 Base Case Capex Projection (£m at 2003/03 prices)

	Adjustment to DPCR4 Forecast					
Item	Gross Market LRE Adjustment	Pension Funding Deficit	Capitalised Overhead	Inter-company Margin	Lane Rentals Adjustment	**Adjusted DPCR4 Forecast**
Gross Load Related	0.0	-8.4	7.8	-2.1	0.0	**237.3**
Non Load Related		-14.6	10.2	-3.9	0.0	**428.7**
Gross Capex less Non Op Capex	***0.0***	***-23.0***	***18.0***	***-6.0***	***0.0***	**666.0**
Non Op Capex (Not Assessed)						**32.4**
Total Gross Capex	**0.0**	**-23.0**	**18.0**	**-6.0**	**0.0**	**698.4**
Contributions	0.0	2.8	-2.6	0.7	0.0	-78.2
Net Load Related	**0.0**	**-5.6**	**5.2**	**-1.4**	**0.0**	**159.1**
Total Net Capex	**0.0**	**-20.2**	**15.4**	**-5.3**	**0.0**	**620.2**
Non Load Related Summary						
Replacement		-9.1	8.5	-2.3	0.0	256.8
ESQCR		-0.4	0.3	-0.1	0.0	10.4
Heath & Safety		0.0	0.0	0.0	0.0	0.9
Environment		-0.6	0.5	-0.1	0.0	16.2
Sub Total - Model Comparison		**-10.0**	**9.4**	**-2.5**	**0.0**	***284.3***
Diversions		-0.4	0.4	-0.1	0.0	11.9
SCADA		-0.4	0.4	-0.1	0.0	12.1
Sub Total		***-10.9***	***10.2***	***-2.8***	***0.0***	***308.3***
Metering (Not Assessed)		0.0	0.0	-0.2	0.0	18.7
Sub Total		***-10.9***	***10.2***	***-2.9***	***0.0***	***327.0***
Fault Capex (Not Assessed)		-3.7	0.0	-0.9	0.0	101.7
Non Load Related Total		**-14.6**	**10.2**	**-3.9**	**0.0**	**428.7**
Total Adjustments	**0.0**	**-23.0**	**18.0**	**-6.0**	**0.0**	**-11.0**

2.2 Load related capital expenditure

2.2.1 Network reinforcement

The level of load related reinforcement is primarily focused on primary network investment. The level of investment is forecast to be £80 m compared to an overall £103 m. The work schedule is therefore specific as opposed to a programmed arrangement. This increases the level of risk due to scope change, project phasing, out-turn unit costs or scheme deferment. UUE's forecast for reinforcement on the network maintains DPCR3 network risk levels. No betterment is provided in terms of lower numbers of 'at-risk' substations. The forecasting procedure appears robust and is acceptable. The number of specific schemes is 64 in total, of which 6 large schemes account for £34 m. Those schemes appear certain in terms of the project timing and need.

2.2.2 New connections forecast expenditure

UUE has based its load related investment programme on historic growth in demand and customer numbers. These projections are supported by data from a number of sources including regional gross value added, housing starts and historical trend analysis by sector. The customer and unit projections appear justified. The level of capital expenditure set against new connections once adjusted for pensions is consistent with that in DPCR3 as would be expected. The level of customer contributions is consistent with DPCR3 percentages and supports UUE's statement that no change to customer contributions during DPCR4 has been assumed. Customer contribution variations in the early part of DPRC3 have been identified and explained.

2.2.3 Load related scheme papers

UUE has provided High-Level Need Statements for a selection of primary schemes that fall to be replaced under P2/5 requirements. These scheme papers are at 'Investment Need' level and still require firm optioneering in order to arrive at agreed schemes and costs. Based on the schemes provided the level of detail supports at high-level the need for investment. The timing of the schemes is front-end biased and as such provides comfort that sufficient firm information should exist to provide certainty of the schemes progressing. No assessment of the forecast expenditure level proposed has been made. Schemes related to replacement due to fault level have not been reviewed on the basis that UUE has provided information that indicates that current switchgear fault level is above the UUE planning threshold which in itself is regarded as appropriate by the 'Overstressing of Distribution Network Operators Report' 2001.

The DPCR3 submission was significantly scaled back in terms of final allowance. In that regard information that may be used to identify possible slippage in the grid and primary programme is inappropriate. UUE has identified, as part of its HBPQ return that capital saving through optioneering has arisen; this is some £3.3 m over the period 2001 to 2003. In general, it may be observed from the information provided, that most of the schemes are yet to go through optioneering and therefore savings through procurement and or alternatives arrangements may arise.

2.3 Comments and issues associated with the load related expenditure forecast

- UUE has estimated future expenditure requirements based on compliance with P2/5, switchgear capacity and network risk. Expenditure set against fault level issues appears justified. In terms of schemes driven by P2/5 compliance then, based on the information provided, the reason for reinforcement appears justified. Expenditure set against Network Risk has increased by £6.6 m although justification for this has been provided. The explanation given appears plausible. The approach adopted by UUE with regard to maintaining constant the number of substations classed, as 'at risk' is appropriate.

- The approach taken by UUE to the forecasting of demand growth has been provided. This methodology appears satisfactory.

- The level of reinforcement is dominated by three main issues:

  a. The forecast has included approximately £7.5 m of Pension cost.

  b. A number of high expenditure site-specific schemes are included. The requirement for these schemes and the phasing of the forecast expenditure has been reviewed and appears justified.

  c. The additional £6.6 m of reinforcement necessary to maintain the level of network risk appears justified based on switchgear fault level and scheme allocation. Overall the level of network risk after allowance for these issues is similar to that for DPCR3. Based on the information provided expenditure in this area appears justified.

- The rate of growth of customer numbers appears to be based on a robust forecasting approach that reconciles the forecast increase with data from a number of diverse information sources.

- UUE's submission has identified a number of site-specific schemes that have contributed to the increase in load-related expenditure increases over DPCR3 levels. Three large schemes together contribute £46 m to the load related forecast expenditure. Based on the information provided, the timing and technical need for the schemes indicate that they have a high probability of proceeding.

- The level of reinforcement driven by fault rating of switchgear is justified based on technical thresholds used to identify site-specific schemes. The forecast variance attributed to this fault rating issue supports £23 m of the additional £46 m identified above. The remaining is driven by P2/5 compliance and primarily related to two of the three large schemes referred to previously.

- Underlying network reinforcement is similar to DPCR3 levels and appears justified.

- The level of customer contributions has been kept constant during the DPCR4 period. This level is commensurate with that observed during DPCR3 with the exception of what UUE has identified as customer mix issues during 2000 –2002. As such, concerns that may exist with regard to possible differences between forecast and actual are limited.

2.4 Non-load related capital expenditure

UUE has forecast replacement based on both a modelled approach and end-of life assessment through health indexing. Non-load related modelling undertaken by UUE has sought to constrain the fault trend through replacement to a constant level throughout DPCR4 period. Overall, this approach has resulted in lower forecast volumes than would have been the case had industry replacement profiles been adopted. This approach tends to address network resilience issue in a direct and transparent manner.

Grid and Primary network expenditure is forecast on a site-specific basis using condition reports and fault history.

Environmental expenditure is influenced by oil filled cable replacement. This accounts for approximately 5% of the fluid filled cable asset population. UUE has made a further allowance for expenditure driven by civil contingencies and increased vandalism. The data that supports this forecast is limited and appears difficult to justify in full.

Health and Safety expenditure is dominated by ESQCR. This expenditure may also be covered by UUE’s overhead line programme or mitigated by subsequent risk assessments.

Secondary network replacement is consistent in volume terms with that delivered through DPCR3 period, albeit individual programmes may have varied.

Additional items being included in DPCR4; pensions and legislative compliance offset increase in non-load replacement compared to DPCR3. The level of difference is also influenced by a reduction in metering market share, cessation of QoS programme in DPCR4 and variation in fault capitalisation. Once allowance for these elements is taken into consideration, the difference between DPCR3 and DPCR4 is £61 m (16%). Allocation of schemes to load and non-load related classes constrains the level of activity level analysis that may be undertaken. However, disregarding legislative compliance and fault capitalisation issues, indicates that the increase in non-load replacement is around 13%.

The company has identified that no allowance has been made in the Base Case for wayleave termination. They have also indicated that wayleave termination activity in DPCR3 has not materialised.

UUE does operate systems to calculate the quality of supply benefits from its investments and has indicated that improvements that may arise as a consequence of Base Case expenditure forecasts are not material.

2.5 Comments and issues associated with non-load related expenditure forecast

- UUE's asset replacement expenditure has been forecast for most asset groups based on Condition Based Risk Management (CBRM) information reconciled to end-of-life through assessment of probability-of failure. This approach appears more advanced that that used by other industry participants. It appears robust in terms of approach and ability to reconcile short-tern and long-term activity to actual work delivered. Concerns do exist with regard to probability of failure mathematical functions and the reconciliation to actual failure rates. In addition determining criticality measures for end-of-life is still not a mature science. However the programme forecast through this method is reported to result in less asset replacement volume when compared to the replacement profiles used in DPCR3. It is appropriate to state that other market participants for DPCR4 forecast have elongated those profiles. Overall the forecast methodology appears robust and comprehensive. Verification through the DPCR4 modelling process will be used to assess the forecast volume and expenditure levels.

- The secondary asset replacement activity identified has been reviewed and the rational provided by UUE based either on condition, safety or performance supports the need for replacement. While certain activities do appear to be in excess of those proposed during DPCR3 further investigation has identified that such variations appear to be supported. Overall the secondary programme volumes do not raise concern. However unit rates still require further assessment against the non-load related model before this matter can be finalised. The issue of unit rates applies to UUE's entire capital forecast.

- HV cable replacement is forecast to be based on reactive policy in keeping with DPCR3 replacement volumes. This appears appropriate. Allowance has been made for LV Consac cable however that allowance is in keeping with previous activity levels. In terms of LV Consac replacement UUE addresses this issue based on cable-joint replacement. This approach was adopted following cable and cable-joint assessment and is regard by UUE as a practical solution. This is a cost effective solution any issue associated with network management rests with UUE. This is not considered to be an issue.

- Overhead line replacement is forecast to be undertaken on a fixed 15-year refurbishment period. This is broadly consistent with industry practice and appears appropriate.

- UUE has made provision for issues associated with ESQCR regulations. The main contributor to the ESQCR forecast of £10.4m is associated with horizontal clearance distances associated with overhead line assets. This is estimated at £4.5 m. Replacement of fused neutral cut-outs is forecast at £4.6 m. In terms of overhead line expenditure saving may be realised through the overhead line replacement programme or other measures that could be taken to mitigate risk. In terms of fused cut-outs expenditure UUE has identified 30 000 units while this volume has not been verified it is broadly consistent with other DNOs.

- LV switchgear exhibits a stable fault rate hence replacement is based on historical practice. This is not considered an issue.
- UUE has indicated that the increase in non-load related expenditure compared to DPCR3 is attributed to activity increase of £23m of which the secondary network asset replacement contributes approximately £10m driven by CBRM results.
- Replacement of Fluid filled cables is included in UUE's forecast. The replacement percentage and supporting information provided by UUE appears to justify including an allowance into this forecast. The capital forecast is for full cable replacement not just replacement of cable-joints. This option constrains UUE's ability to change scope of the proposal mid review.
- Overall the level of expenditure increase on grid and primary asset replacement is relatively low at £2.0m. Individual asset class do show variations between reviews. This would be expected as expenditure is reprioritised. A concern does exist in terms of the supporting 'Need-Statements' for the site specific schemes.. These documents are of limited value and inadequate to justify expenditure levels proposed. However, this may be rationalised on the basis that the documents are aimed at indicating a need for investment and at that stage in the planning process the need to express detail may not be required for internal purposes.

2.6 Quality of supply/sensitivity scenarios

2.6.1 Network performance improvements

Table 2.3 - Total QoS measures for quality of supply scenario

02/03 Actual		01/02 & 02/03 Average		2010 Scenario		2020 Scenario		Average/2010 (%)	
CI	CML	CI	CML	CI	CML	CI	CML		
64.3	62.7	59.4	60.8	59.3	56.8	59.3	50.7	100	107

UUE's approach to the modelling of QoS initiatives is robust and well supported in terms of data and systems. The main focus of priority in terms of investment is targeted at reducing CMLs. CI is viewed as a relatively easier task.

2.6.2 Quality of supply – improvement scenario

UUE has proposed a programme for improvement in quality of supply of some £17.2 m. This is mainly associated with further remote control and automation, fitting of protection and retrofit of asset control mechanisms. These two initiative accounts for £13.6 m of the overall expenditure forecast. Installation of remote control and automation devices will result in a degree of network reconfiguration in terms of ability to increase network sectionalisation. All options have been assessed and ranked in terms of optimum cost-benefit delivery. This is a low expenditure level and raises only slight concern.

2.6.3 Quality of supply – sensitivities

UUE has approached the +/-2% scenario based principally on increment or decrement of the initiatives identified in the main QoS improvement scenario. The additional cost for a +2% improvement in CI is forecast to be an additional £7.6 m. This is delivered primarily through remote control and automation. This is reported to provide 2.1% improvement to CML and appears an appropriate initiative to consider.

The 5% improvement in CML is delivered through additional remote control and automation building on the base QoS initiative. The additional cost is £34.2 m. While this is a relatively low cost option the decrease in cost: benefit ratio and single CML improvement suggests that the initiative may be reaching its limit in terms of application. However, overall the initiative does provide substantial customer benefit with both increases in CML and CI. The CI increase is forecast to be 5.6%.

UUE has forecast a reduction in forecast capital expenditure associated with a 2% CI deterioration of £5.6 m with an associated 1.6% CML loss. A 5% CML deterioration results in a saving of £13.5 m. This saving is delivered by reducing the activity associated with remote control and automation as well as reduction in the Hand Reset Relays and modifications to protection devices. The 5% CML deterioration also results in a 10% CI reduction. Based on network performance whilst this does deliver the CML reduction specified it also impacts on CI performance. This appears from a network performance perspective to be counter-productive. Given the initiatives proposed then impact on both CML and CI would be expected. No assessment of the level of performance degradation has been undertaken.

2.6.4 Accelerated line upgrade

Upgrade of the overhead line is contained within the Base Case. Accelerated overhead-line upgrade project option 1 is forecast at £274.5 m. Option 2 is reported at £52.6 m. Both of these options involve increase network resilience through application of EATS 43-40 design standards. The variation between the two options relates to the delivery date for completion of the proposal. The unit costs provided are those in Base Case submission. The level of the unit cost provided may be reviewed following verification of the NLRE model.

2.6.5 Under-grounding existing overhead line (network resilience)

Under-grounding resilience has been modelled based on 2% of all voltages; Option 1, or only 2% of HV overhead line; Option 2. The expenditure forecast is 74.2 m or 3.9 m respectively.

The unit costs provided are those in the Base Case submission uplifted by 210%. The unit cost level may be reviewed as part of the NLRE model verification. UUE has indicated that since such a programme would most likely be targeted at HV overhead lines that are non 43-40 compliant then Option 2 is most likely to proceed.

2.6.6 Under-grounding existing overhead line (amenity value)

Under grounding for amenity value is forecast by UUE as likely to require investment in the order of £1.1 bn. This is based upon under-grounding across all voltage levels. Given the type of area and ground condition the unit cost as set out in UUE's Base Case has been uplifted by 410%.

2.6.7 Comments and issues associated with quality of supply scenarios

- The approach taken by UUE to QoS initiatives and scenario assessment appears robust and comprehensive not only at the general initiative level but also project level. This degree of detail and modelling has allowed UUE to appraise the cost: benefit of the QoS initiatives and projects on an incremental basis.

- The Remote Control and Automation option appears to deliver good benefit for QoS at a relatively low expenditure level. The expenditure level appears justified.

- The increment and decrement scenarios support the remote control and automation initiative in terms of flexibility of implementation. For all scenarios the options provided by UUE appear appropriate and match adjustments to the underlying initiative.

- UUE's approach to upgrade and under-grounding network resilience is based on improvement to the HV network. This is an appropriate target for improvement delivering maximum cost: benefit for customers. The work programme is forecast as flat during DPCR4 this is a pragmatic decision given the uncertainty of the scenario. The unit cost level that underpins the volumes identified requires further analysis.

- Under-grounding for amenity value is not a preferred option given the low cost: benefit ratio. UUE's view on this appears appropriate.

DNO alternative case

The DNO scenario includes £106 m for added expenditure as a consequence of Distributed Generation and the need to replace switchgear due to technical limitations of the affected switchgear.

3. SECTION B - PB POWER MODELLING AND COMPARISONS

3.1 Introduction

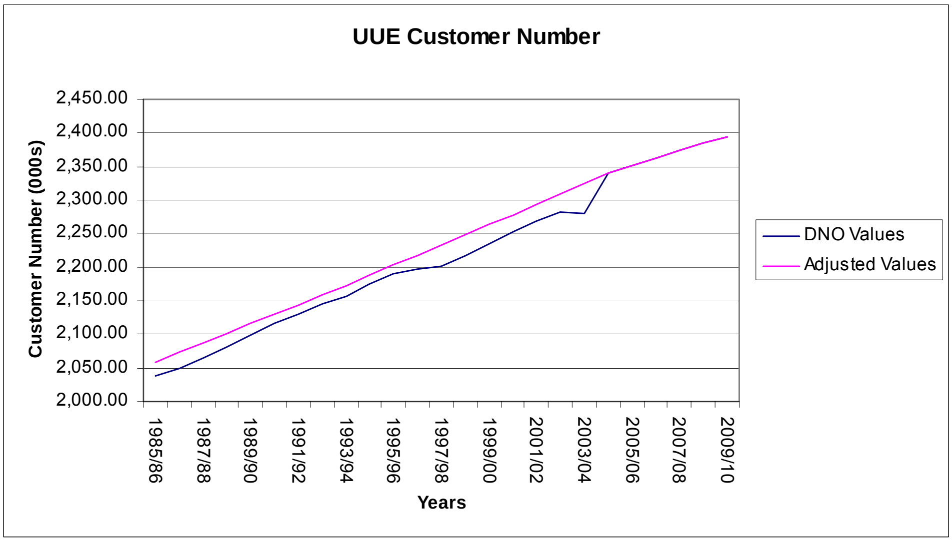
PB Power has carried out modelling of forecast expenditure using both DNO data and PB Power data with a view to understanding better how DNOs have arrived at forecast expenditure and with a view to informing Ofgem of issues that may be considered in arriving at allowances for DPCR4.

Detailed descriptions of the models are provided in Appendices D, E & F and the following sections discuss the validation and adjustment of the input variables and the model outputs.

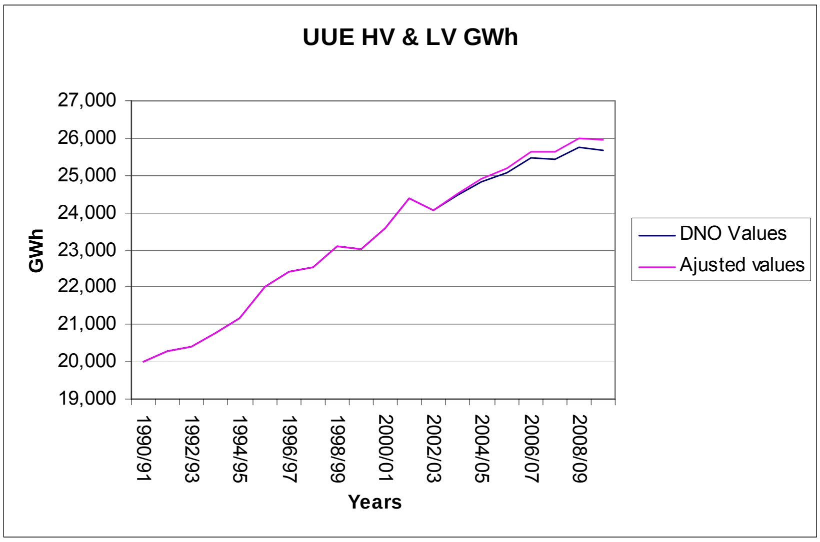
3.2 Load related expenditure

3.2.1 Model inputs

A step change occurs within UUE's customer numbers between 2002/03 and 2004/05. To remove this step an average growth rate of 0.67% has been applied working back from 2004/05. The average growth has been calculated from the customer numbers between 1986/87 and 2001/2002.



From the GVA analysis carried out UUE have had their GWh forecast increased. This adjustment takes the form of a 39 GWh increase year on year from 2003/04 to 2009/10. The increased value used has been calculated as part of the GVA analysis.



The only other amendment to data undertaken for UUE was to make allowance for the year 95/96 to 97/98 where information relating to LV Service and Metering was submitted combined.

3.2.2 Model outputs

The following table sets out the model output compared to the actual DPCR2 expenditure, the actual and forecast DPCR3 expenditure and the DPCR4 submission.

Table 3.1 - Load-related expenditure model outputs

LRE DPCR2 (excluding generation)	**LRE DPCR3 (excluding generation)**	**Adjusted LRE Gross DPCR4 (excluding generation)**	**Model Output LRE for DPCR4**
(£m)	(£m)	(£m)	(£m)
166	173	237	**212**

3.2.3 Load related expenditure modelling comments

The model output indicates that UUE's forecast is high in relation to customer growth. Accordingly we project a level of load-related expenditure that is about £16m below the forecast.

3.3 Non-load related expenditure

3.3.1 Model inputs

No specific model input adjustments were made for UUE.

With minor exceptions, assets were modelled on an age based replacement profile basis.

3.3.2 Model outputs

Table 3.2 below provides a comparison between the DNO submission and the model outputs for the main asset classes.

Table 3.2 - Comparison of NLRE Model Outputs with DNO Submission (£m)

Submission	FBPQ Table 26	Adjusted submission	Combined	Adjusted submission	Model output	Bench-marked output	PB Power Opinion
Lines	93.8	92.3	Lines & services	105.8	71.1	76.6	
Cables	30.9	30.4	Cables & services	34.4	83.2	34.4	
Transformers	27.3	26.8	Substations	142.6	179.9	142.6	
Switchgear	89.2	87.8	Part Submission Total	282.8	334.3	253.6	
Services and Lines	17.8	17.5					
SMC	0.0	0.0					
Other Substations	28.5	28.0					
Other Not Modeled	0.0	0.0	Other Not Modeled	0.0		0.0	
Total	287.5	282.8	Total	282.8		253.6	273.9

3.3.3 Non-load related expenditure modelling comments

The model generates lower overall expenditure than the forecast largely because the model predicts lower expenditure on overhead line replacement, in particular at HV and EHV. UUE's lives of these assets are consistent with the industry average lives, although it is noted that these asset lives do not drive UUE capital replacement forecasting system with greater emphasis being placed instead on "health indices" data. This different approach tends to constrain any detailed analysis of variances. Nevertheless variation in volume and unit price does exist between the modelled output and UUE submission. The main adverse variance, submission compared to model, is in EHV asset class and is primarily unit cost driven (UUE's unit costs are high).

For substations the model generates a slightly higher expenditure than the UUE forecast and this difference is mainly attributed to transformer related expenditure. It is our view that this difference is a direct result of UUE health indices based approach to capital forecasting.

For underground cabling the model predicts higher expenditure than the forecast and this difference is driven primarily by volume variance in the LV and HV asset classes. Contribution to the variation between the model output and submission driven by unit price difference is negligible. The modelling for this asset class is based on a "back-fit" of the replacement profile to industry activity, which for the majority of DNOs has been forecast based on consistent DPCR3 activity. This may lead to a view that the cable replacement attributed by UUE to non-fault replacement is lower than for other network operators. However much of the LV cable replacement is using plastic waveform construction which provides a non like-for-like replacement for Consac. UUE's forecast cable replacement for this particular asset is lower than the industry rate that no doubt contributes to the explanation of difference between modelled output and submission.

The modelled output, with the exception of the EHV and HV overhead line asset classes, reflects to the capital expenditure level submitted by UUE. The submission level appears to have been constrained for certain asset types by the asset management approach adopted by UUE. Where differences do exist, in particular EHV and HV overhead lines then additional information is available to provide an explanation as to the rational for that difference. That information informs the view of the non-load related capital allowance level recommended by PB Power.

In PB Power's opinion, the allowed non-load related expenditure corresponding to the model output should be £273.9 being the adjusted DPCR4 forecast less ESQCR expenditure of £10.4m. This amount excludes ESQCR expenditure, diversions, metering and fault capital expenditure. Furthermore ESQCR expenditure has been excluded from the overall total as this matter is being considered separately.

3.4 PB Power's opinion of allowances

Our findings are summarised in the table below.

Table 3.3 – PB Power's Opinion of Allowances (£m)

Item	Adjusted DPCR 3 Projection	Adjusted DPCR4 Forecast	Model Output, benchmarked	PB Power Opinion
Gross Load Related	**172.6**	**237.3**	**212.5**	**221.0**
Non Load Related	**388.7**	**428.7**		**416.9**
Gross Capex less Non Op Capex	**561.3**	**666.0**		**637.9**
Non Op Capex (Not Assessed)	49.0	**32.4**		32.4
Total Gross Capex	**610.3**	**698.4**		**670.3**
Contributions	-87.1	-78.2		-78.2
Net Load Related	**85.5**	**159.1**		**142.8**
Total Net Capex	**523.2**	**620.2**		**592.0**
Non Load Related Summary				
Replacement		256.8		
ESQCR		10.4		
Heath & Safety		0.9		
Environment		16.2		
Sub Total - Model Comparison	***242.4***	**284.3**	**253.6**	**273.9**
Diversions	9.7	11.9		10.4
SCADA	9.7	12.1		12.1
Sub Total	***261.8***	***308.3***		***296.4***
Metering (Not Assessed)	44.0	18.7		18.7
Sub Total	**305.8**	***327***		**315.1**
Fault Capex (Not Assessed)	82.8	101.7		101.7
Non Load Related Total	**388.7**	**428.7**		**416.9**

Notes:

- Non operational capital expenditure has not been assessed
- Non-load related expenditure modelling covers all non-load related headings except diversions, metering, fault capex and SCADA
- Metering and fault capex are passed through
- Diversions are passed through, where compliant, with the Base Case the same as for DPCR3

- SCADA is separately assessed but not included in the modelling

- PB Power's asset replacement model output and Opinion are based on retirement profile modelling and exclude any additional expenditure that may arise under ESQCR legislation.

APPENDIX A

BASE CASE SUBMISSION

APPENDIX A – BASE CASE SUBMISSION

UUE has stated that the Base Case submission is predicated on maintaining the fault rate performance constant at 2002/03 levels with no additional expenditure being incurred on Quality of Supply initiatives or major operational changes. The Base Case Projected Capital Expenditure follows the Ofgem FBPQ guidelines and is summarised as follows:

A.1 Actual and forecast capital expenditure projection for DPCR3

In the table below we present the actual and forecast capital expenditure projection for DPCR3. The net load-related expenditure for the period is £97.3 m and overall gross capital expenditure £610.4 m.

Table A.1: Actual and forecast capital expenditure projection for DPCR3 (£m at 2003/2003 prices)

	← Actual →			Forecast		Total
	2000/01	**2001/02**	**2002/03**	**2003/04**	**2004/05**	
Capital Expenditure						
Load Related	35.3	36.7	35.1	37.1	40.3	184.5
CAPITAL CONTRIBUTIONS	(19.5)	(21.4)	(15.4)	(15.4)	(15.5)	(87.2)
Non Load Related	72.7	67.2	78.1	83.6	75.3	376.9
Non-operational capex	6.8	14.9	9.1	10.9	7.3	49.0
Total Capital Expenditure	95.3	97.4	106.9	116.2	107.4	523.2

A.2 Base Case capital expenditure forecast for DPCR4

The Base Case Capital Expenditure Forecast for DPCR4 follows the Ofgem FBPQ guidelines and is summarised as follows:

Table A.2: Base Case capital expenditure forecast for DPCR4 (£m at 2003/2003 prices)

	Forecast					Total
	2000/01	2001/02	2002/03	2003/04	2004/05	
Capital Expenditure						
Load Related	50.2	47.4	51.9	49.5	40.5	239.8
Capital Contributions	(15.6)	(15.8)	(15.8)	(15.9)	(16.0)	(79.1)
Non Load Related	87.9	88.1	87.3	87.3	86.5	437
Non-operational capex	6.2	6.7	5.6	6.7	7.2	32.4
Total Capital Expenditure	128.7	126.4	129	127.6	118.2	630.1

A.3 Projections of future load related capex

UUE's load related capital expenditure projections for the Base Case Scenario are as set out in the following table:

Table A3: Base Case forecast

	Load Related (£m)					
Expenditure Classes	**2006**	**2007**	**2008**	**2009**	**2010**	**Total**
LRE	50.2	47.4	51.9	49.5	40.5	**239.8**
Contributions	-15.6	-15.8	-15.8	-15.9	-16.0	**-79.1**
Net LRE	34.6	31.9	36.1	33.6	24.5	**160.7**

A.4 Network reinforcement

In UUE the SCADA system provides actual maximum demand, time and date of maximum demand for each circuit i.e. 33 and 132 kV, for each primary (33/11 kV) substation and bulk supply point (132/33 kV). This information is available for each month of the year and is used to ascertain actual maximum demand. The demand is corrected to Average Cold Spell (ACS) condition.

To produce future forecasts UUE use factors such as historic growth trend, local economic factors derived from district and county structure plans and known local developments that are added to actual ACS maximum demand.

UUE's forecast of grid and primary expenditure is based on detailed assessment taking into consideration site-specific load growth and possible load transfers. The level of reinforcement therefore considers P2/5 limitations along with fault duty of switchgear.

Reinforcement expenditure associated with HV is, given the number of substations and increased complexity with regard to interconnection, forecast based on a statistically robust sample of the HV network supported by network simulation. As with the approach to grid and primary assessment the HV network modelling is stressed in keeping with demand forecasts. The reinforcement thresholds associated with P2/5 compliance, switchgear fault level, thermal limits and voltage level compliance are used as a guide to the need for reinforcement and subsequently level of network risk.

The main driver for reinforcement across the UUE network is based on risk assessment. Where risk is related to a number of broad measures such as:

- the level of the substation demand above the nominal rating, headroom:
- timing of reinforcement need and
- operational restrictions and limitations.

Using a weighting system based on the measures above an optimum reinforcement schedule can be developed that seeks to maintain the risk at an acceptable level.

In order to arrive at this level for the HV network system modelling has been undertaken for 18% of the HV circuits. This modelling exercise has been supported by operational views with regard to peak load network switching necessary to alleviate demand during network outage situations. This approach seeks to combine a theoretical model with actual operational practice.

In forecasting the reinforcement expenditure requirement UUE has sought to maintain the number of substations that are classed as being 'at risk' at a constant level. This results in certain substations being proposed for reinforcement and other substations being increased in terms of their individual risk classification. The use of site-specific load growth data at grid and primary level may also results in other substations not previously regarded as being 'at risk[1]' now requiring review. Table A4.1 sets out the number of substations that are now classed as 'at-risk' compared to those identified in DPCR3. The term at-risk is used by UUE to relate the number of relates

Table A4.1: Change in overall 'at-risk' substations by voltage level

	Current	**2010**
Grid Network	16	8
Primary Network	86	99

At-risk on the HV system given the greater complexity of the analysis is undertaken in a different manner and relies more on a sampled approach. As such UUE has not provided an indication of the HV at-risk position. This bottom-up analysis both at grid, primary and to a lesser degree HV has also been verified using a more general top-down model of the UUE network based on marginal cost of reinforcement.

Overall the approach to forecasting reinforcement is comprehensive and well founded. It is also appropriate to state that the level of reinforcement being forecast reflects the main objectives of the Base Case scenario.

UUE has forecast expenditure across all voltage tranches with the main expenditure occurring on the 132 kV network. Table A4.2 below identifies the level of forecast capital expenditure by voltage level and expenditure driver:

Table A4.2: Forecast reinforcement expenditure by voltage level for DPCR4

Network Type	**132 & 33 kV**	**HV**	**LV**	**Total (£m)**
P2/5 Compliance	37.0			**37**
Existing Network Risk	16.2	23.5*	3.9	**43.6**
Fault Level	26.4	0.9		**27**
HV Transformers		1.9		**2**
Total	**79.6**	**22.0**	**3.9**	**105**

1 At-risk is defined by UUE as risk from the number of network sections which are over 100% loaded now and the percentage of overloaded compared that with the same calculation at period end. A nil change in at-risk therefore reflects the implementation of projects until the point where the net sum of this overload (number of sections weighted by overloaded) is equal

* This number has been adjusted from £19.2 m to £23.0 m in order to reconcile with total variance numbers in table A4.4. The adjustment is based on a UUE report that was provided in order to confirm changes in the level of Network Risk.

Table A4.3: Forecast reinforcement expenditure by voltage level for DPCR3

Network Type	**132 & 33 kV**	**HV**	**LV**	**Total (£m)**
P2/5 Compliance	8.8			**9**
Existing Network Risk	16.0	15.5	3.9	**35**
Fault Level	4.1			**4**
HV Transformers		1.9		**2**
Total	**28.9**	**17.4**	**3.9**	**50**

Table A4.4: Comparison of DPCR3 to DPCR4 by reinforcement expenditure driver

Reinforcement Driver3	**DPCR3 (£m)**	**DPCR4 (£M)**	**Variance (£M)**
P2/5 Compliance	9.0	37.0	28.0
Fault level	4.0	27.0	23.0
Network Risk*	36.0	43.6	6.2
Total	50.4	105.0	55.3

* Pension contribution has been netted from the DPCR4 value for comparative purposes.

UUE has provided a list of the main schemes at grid and primary level that are forecast to be requiring reinforcement during the DPCR4 period. Those schemes driven by P2/5 compliance and at 132 kV are set out in table A4.5 below.

Table A4.5: Reinforcement driven by P2/5 compliance

Site/Area	**Cost (£m)**
Ribble BSP	17.9
Leyland BSP/Wrightington BSP	associated with above
Bury - Radcliffe P2/5 over 100 MW group	2.5
Skelmersdale - Wigan P2/5 over 100 MW group	12.2
Stuart Street BSP	1.1
Penrith BSP/Shap BSP	0.7
West Didsbury BSP	2.5
Altrincham BSP/Sale BSP P2/5 over 100 MW group	will be solved by West Didsbury solution
Total	**£37.0 m**

In addition the UUE has identified 17 individual reinforcement schemes that are driven by fault level problems. In total these schemes sum to £25.5 m of which Kearsley GSP accounts for £12.8. This scheme will be discussed later. The remaining schemes on average stand at approximately £0.7 m and are predominantly primary network related. A listing of the schemes is set out in table A4.6.

Table A4.6: Forecast reinforcement driven by switchgear fault level considerations

Site/Area	**Make rating exceedance?**	**Break rating exceedance?**	**Cost (£m)**
Ribble - Bamber Bridge	✓		0.6
Heyrod - Hurst	✓	✓	0.8
Carrington - Irlam	✓	✓	0.6
Blackpool – Cecil Street	✓	✓	0.6
Lancaster – Westgate	✓		0.8
Stuart Street – Ardwick	✓	✓	0.9
Burnley – Burnley	✓		1.0
Burnley – Heasandford	✓		0.6
Adswood – Cheadle Heath	✓		0.6
Nelson – Clover Hill	✓		0.6
Barton – Lyons Road	✓	✓	0.6
Nelson – Spring Cottage	✓		0.9
Stretford - Trafford	✓	✓	1.5
Macclesfield – Withyfold Drive	✓		0.9
Kearsley GSP	✓		12.8
Kearsley – Frederick Road	✓		0.7
Earsley – Bolton Grid	✓		0.9
Total			**£25.5 m**

The main increase in reinforcement forecast sits within increased P2/5 compliance and reduction in fault level problems. In terms of fault level the increase, 50% of that forecast increase is due to a single project. The remaining £10 m is driven by a number of smaller schemes. Table A4.7 below identifies the fault level percentage associated with fault level driven reinforcement proposals. This approach of 100% is acceptable and leads to the conclusion that reinforcement driven by fault level appears justified. It is also worthy of note that the decision to require reinforcement at this level provides a capital expenditure saving when compared to, a yet to be agreed, industry accepted planning margin. The decision based on 100% is supported by 'Overstressing of Distribution Network Operators Report' 2001.

Table A4.7: Make and break capacity of fault driven reinforcement

Substations		Primary Fault Levels - 11kV & 6.6kV				
S/S Group	Primary S/S or Busbar Name	Total 11kV/6.6kV Make Fault Level		Total 11kV/6.6kV Break Fault level		
		Peak Asym : kA	% of Make Rating	RMS Sym : kA	% of Break Rating	DPCR4 Estimated Cost (£k)
Ribble	BAMBER BRIDGE	21.88	111.1%	7.12	90.4%	572
Heyrod	ASHTON UNDER LYNE	59.25	118.5%	18.62	93.1%	0
Heyrod	HURST	38.88	116.4%	13.22	100.9%	780
Carrington	IRLAM PRIMARY	35.31	105.7%	13.22	100.9%	625
Blackpool	CECIL ST	33.50	100.3%	13.13	100.2%	624
Lancaster	WESTGATE	33.57	100.5%	12.63	96.4%	832
Stuart Street	ARDWICK	33.94	101.6%	13.14	100.3%	937
Burnley	BURNLEY CENTRE	33.72	100.9%	12.78	97.6%	988
Burnley	HEASANDFORD	34.33	102.8%	12.86	98.2%	624
Adswood	CHEADLE HEATH	34.46	103.1%	12.28	93.7%	624
Nelson	CLOVER HILL	37.35	111.8%	13.04	99.6%	624
Barton	LYONS RD	38.56	115.4%	14.65	111.8%	624
Nelson	SPRING COTTAGE	37.27	111.6%	12.74	97.3%	884
Stretford	TRAFFORD	33.98	101.7%	13.13	100.2%	1456
Macclesfield	WITHYFOLD DRIVE	34.48	103.2%	10.97	83.8%	936
Kearsley GSP	Kearsley GSP	Fault level (132kV) prevents substation being run with full firm capacity, derogation in place (work begins in XD3)				12,750
		33kV fault level				
			% of Make rating		% of Break Rating	
KEARSLEY	FREDERICK ROAD		108.9%		92.2%	722
kEARSLEY	BOLTON GRID		100.3%		80.6%	914
					Total	25,519

Kearsley Reinforcement is a site-specific scheme that contributes 12.8 m to DPCR4 and £3.0 m in DPCR5. This scheme has been reviewed and appears to be justified. In addition to business case justification and technical issues set out in internal documents UUE has also provided a copy of the derogation letter from Ofgem agreeing to derogate non-compliance till 2006 whereupon UUE has agreed to take action to remove the non-compliant plant.

The forecast expenditure necessary to deal with Network Risk is an additional £6.6 m over DPCR3 expenditure level. This 13% initially increase appears at odds with UUE's statement that network risk has not increased or decreased. In addition a 13% increase compared to DPCR3, without assessment of individual schemes, is considered high based on an approximate 1% increase in demand. UUE has indicated a large number of schemes are classed as 'at-risk' and therefore any increase may be attributed to movement between different scheme type into and out-of the ‘at-risk’ class. UUE has also advised that the change in Network Risk is driven primarily through allocation issues associated with Skelmersdale reinforcement, £1.0 m to the Network Risk classification as well as increased HV transformer replacement, some £1.9 m. Increased activity driven by fault level related to switchgear contributes a further £0.9 m. Overall the explanation of this difference appears justified given that headroom on the network is tightening and the threshold levels adopted by UUE prior to reinforcement.

A number of site-specific schemes have been identified that are also tied to agreed programme of works with NGT. Table A4.8 below identifies the joint schemes with NGT that are due to commence during DPCR4.

Table A4.8: Agreed joint developments with NGT

Project Id	Project Title	Project Total (£m)
90010804 (Condition Related)	Rochdale 132 kV Switchgear Replacement	12.1
90013832 (Condition Related)	Harker 132 kV S/Stn – Refurbishment of support structures and Switchgear Replacement	3.1
90009438 (Condition Related)	Penwortham 132 kV Switchgear Replacement	5.7
90015493 (Reinforcement)	Kearsley Replace 132 kV Switchgear	15.2

This table also adds support to the decision to recognise Kearsley reinforcement.

UUE site-specific part-programme for reinforcement associated with P2/5 and fault level is set out in Table A4.9 below. Individual schemes associated with P2/5 have been detailed along with a total line for fault level expenditure. The table indicates that the site-specific investment is front-end biased with regard to expenditure. Schemes proposed for 2005/06 increases in certainty in terms of network information and planning. This expenditure shape increases confidence that the site-specific programme proposed would actually proceed.

Table A4.9: Site-specific expenditure profile

Site/Area	2005/06	2006/07	2007/08	2008/09	2009/10	ToTal (£m)
Ribble BSP	0.9	5.6	5.6	3.2	2.2	**17.6**
Leyland BSP/ Wrightington BSP	-	-	-	-	-	
Bury-Radcliffe	0	0	0	1.3	1.0	**2.4**
Skelmersdale – Wigan	0	0	4.1	4.1	2.5	**10.8**
Stuart Street BSP	0	1.2	0	0	0	**1.2**
Penrith / Shap BSP	0.3	0.3	0	0	0	**0.7**
West Didsbury BSP	1.1	0.5	0.8	0	0	**2.4**
Altrincham BSP/ Sale	-	-	-	-	-	
Lancaster	0.7	0	0	0	0	**0.7**
Total P2/5	3.1	7.7	10.5	8.6	5.8	**35.7**
Total Fault Level	25.5	13.6	6.1	3.4	3.2	**25.5**
Overall	28.6	21.3	26.6	12.0	9.0	**61.2**

A.5 New connections forecast expenditure

UUE approach to forecast of new connection expenditure is based on assessment of historical activity based on change in Meter Point Administration Numbers. This information indicates that customer numbers grow by 0.5% per annum domestic and 0.6% non-domestic. This is supported by regional economic information and detail from a number of other sources including National House Builders Federation. Known larger developments are reviewed and also considered. Including known developments and regional economic data are not mutually exclusive. UUE's approach to forecasting new connection drivers and expenditure appears appropriate. The level of capital expenditure forecast by UUE is set out in Table A5.1 and Table A5.2 below. This identifies the level of new connection expenditure attributed each main sector.

Table A5.1: Forecast new connections activity

(£m)	2005/06	2006/07	2007/08	2008/09	2009/10	Total
New housing (domestic)	14.3	14.4	14.5	14.6	14.7	**73**
Industrial & commercial	6.2	6.2	6.3	6.3	6.4	**31**
Unmetered	2.2	2.3	2.3	2.3	2.3	**11**
Total (gross)	**22.7**	**22.9**	**23.1**	**23.2**	**23.3**	**115**
Contributions	(15.6)	(15.8)	(15.8)	(15.9)	(16.0)	(79)
Total (net)	**7.1**	**7.1**	**7.3**	**7.3**	**7.3**	**36**

Table A5.2: New connections activity in DPCR3

(£m)	2000/01	2001/02	2002/03	2003/04	2004/05	Total
New housing (domestic)	16.1	14.3	12.6	14.2	14.3	**72**
Industrial & commercial	6.8	8.4	5.8	6.0	6.1	**33**
Unmetered	2.4	1.8	2.2	2.2	2.2	**11**
Total (gross)	**25.3**	**24.5**	**20.6**	**22.5**	**22.6**	**116**
Contributions	(19.5)	(21.4)	(15.4)	(15.4)	(15.5)	(87)
Total (net)	**5.8**	**3.1**	**5.2**	**7.1**	**7.1**	**29**

The above submission includes £7.5 m of enhanced pension contributions of which £3.5 m is within non-connection activities. UUE has reported that the DPCR3 figures include £3.4 m of Distributed Generation connections and £2.6 m of Distributed Generation related income for the 2001-2003 period. No Distributed Generation assumptions have been included for the 2006-2010 period.

Forecast new connections expenditure is relatively flat. This leads to the conclusion that no issue appears to exist with this activity. UUE has advised that the capital contribution policy applied for the period 2006 to 2010 is consistent with that applied during DPCR3. In that regard net new capital expenditure is also regarded as acceptable. The £12m swing between DPCR3 and DPCR4 may be attributed in part to loss of Distributed Generation capital receipts. Unmetered activity appears fixed hence reduced capital receipts due to that activity is not applicable. UUE has identified that the early DPCR3 variation is attributed to scheme mix and large connections as well as changes to the contribution policy. On the basis that mid to late DPCR3 is consistent with that forecast for DPCR4 tends to support the view that capital contributions are not an issue.

UUE has provided High-Level Need Statements for a selection of primary schemes that fall to be replaced under P2/5 requirements. Comment on the Need Statements is, where necessary, detailed below:

- Wigan – Skelmersdale 33 kV reinforcement; P2/5 driven. This project is proposed in order for UUE to remain licence compliant through load growth on the network. The information reviewed is the Investment Needs Statement. The total cost profile is £1.1 m due to be incurred in 2004/05. Based on the detail provided this scheme would appear to have a high probability of proceeding.

- Ribble BSP reinforcement P2/5 driven. This project is proposed based on forecast load growth at Ribble BSP. The current substation is over firm capacity by 23 MVA based on a firm capacity of 216 MVA. The substation is due to be non compliant in 2007/08. No information has been provided with regard to load transfer capabilities. On the basis that the peak demand measured is at normal operating configuration then reinforcement would appear justified. The scheme is forecast at £1.9 m with phasing due over 20004/05 and 2005/06. It would appear that this scheme has already been deferred from DPCR3. No information has been provided that would allow a view to be formed as to the risk of the scheme not proceeding in DPCR4. The date and technical information suggest that this should be considered as having a high probability of proceeding, although issues detailed below may negate the requirement.

- Preston BSP reinforcement P2/5 driven. This scheme happens to be associated with the problems at Ribble BSP. The option proposed is to provide a new BSP at Preston that is intended to provide long-term load growth capacity and avoid P2/5 compliance issues in the surrounding network. The project is forecast at £16.7 m to be incurred in 2006. Based on the information presented with regard to timing then the need to proceed with the Ribble BSP reinforcement, appears initially to be unjustified. Further information provided by UUE has subsequently confirmed that the scheme to transfer load is required to support Ribble BSP before Preston can be commissioned. On that basis and given that the scheme is close-up to DPCR4 increases certainty that it will be expected to proceed.

A.6 Non-load related expenditure

The amount of non-load related expenditure projected by UUE for the Base Case Scenario is set out in Table A6.1.

Table A6.1: Non-load related expenditure

Expenditure Classes	Non-Load Related (£m)					
	2006	2007	2008	2009	2010	Total
Non Fault Replacement	54.9	55.0	54.3	54.0	53.7	**271.9**
Metering	3.7	3.9	3.8	4.0	3.5	**18.9**
Faults	21.3	21.3	21.3	21.3	21.3	**106.4**
Diversions	2.4	2.4	2.4	2.4	2.4	**12.0**
Health and Safety	2.3	2.3	2.3	2.3	2.3	**11.4**
Environmental	3.3	3.3	3.3	3.3	3.3	**16.4**
Total	**87.9**	**88.1**	**87.3**	**87.3**	**86.5**	**437.0**

UUE has provided a high-level reconciliation between DPCR4 and DPCR3. Which clarifies expenditure variation. This information is set out ion Table A6.2 below.

Table A6.2: Reconciliation of movement between DPCR3 to DPCR4 for non-load related expenditure[2]

All values in £m 02/03 prices	DPCR3	DPCR4	Variance	Variances					
				FRS15	Safety & Environment	Activity increase	Loss of market share	Cessation of QoS	Pension
Asset Replacement	221	260	39			23			16
Faults	84	107	23	16					7
Compliance		28	28		26				2
Diversions	11	12	1						1
Metering	38	19	-19				-20		1
Operational IT	10	12	2			1			1
QoS	13		-13					-13	
NLRE Sub-total	**377**	**438**	**61**	**16**	**26**	**24**	**-20**	**-13**	**28**

Table A6.2 indicates the underlying difference between DPCR3 and DPCR4 is £50 m or 13.2% of DPCR3 expenditure. Excluding ESQCR forecast expenditure results in an underlying positive variance to DPCR3 of £39.5 m or 10.5%.

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[2] The data set out in table A6.2 is based on UUE submitted data and does not include Ofgem adjustments.

A.7 Environment, health & safety expenditure

UUE has identified specific issues within the Base Case that in aggregate contribute in the order of £15 m to forecast environmental, health and safety expenditure. The single largest contributor is associated with ESQCR. This accounts for £10.4 m.

Table A7.1: Proposed activity related to ESQCR

	2005/06	2006/07	2007/08	2008/09	2009/10	Total
Stays (no)	1 010	1 010	1 010	1 010	1 010	**5 050**
Stays (£m)	0.3	0.3	0.3	0.3	0.3	**1.4**
Cut-outs (no)	6 250	6 250	6 250	6 250	6 250	**31 000**
Cut-outs (£m)	0.9	0.9	0.9	0.9	0.9	**4.6**
Clearances (£m)	0.9	0.9	0.9	0.9	0.9	**4.5**
Total capex (£m)	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**10.5**

UUE's interpretation of the DTI's requirements has made no allowance for avoidance of expenditure through appropriate network risk assessments. Within non-load related expenditure allowance has been made for replacement of overhead services and line. UUE appears to have made no allowance for possible savings that may be realised due to replacement of end-of-life assets that are also ESQCR non-compliant. Replacement of stay wires (£1.4 m) is another activity where opportunities for saving through the application of a co-ordinated approach addressing the needs of the forecast overhead line programme and ESQCR demands may result in capital expenditure savings.

At present the estimate of the impact attributable to ESQCR is based on a high-level assessment. Savings that may be delivered through a targeted replacement programme for both overhead lines and services are only likely to be identified following a more detailed assessment once an agreed programme of works is developed. It is acknowledged that ESQCR in most instances may not be the principle driver and therefore the ability to deliver a replacement programme coincident with avoidance of additional ESQCR expenditure may not always be possible.

It is possible that through a combination of risk-assessment and targeted replacement that the majority of the overhead line accessibility expenditure may be avoided.

Replacement of cut-outs is more definitive with regard to the obligation placed on the DNO. This is an activity that needs to be undertaken. UUE has advised that the estimate has been based on the current volumes being generated by the 20-year statutory meter change programme. UUE has indicated that it is in the process of developing risk assessments and that it considers the risk as low.

It is recognised that further discussion between DTI and Ofgem and individual DNOs is required in order to determine an agreed position across the industry on this issue.

Two relatively minor expenditure items have been identified. Together these account for £7.0 m during DPCR4.

- UUE has identified a further £3.0 m for civil works associated predominantly with cable bridges some £2.0 m and cable tunnels £1.0 m. Historical expenditure in this area, over a three-year period, has been reported as £0.5 m cables bridges with a further £1.3 m for cable tunnels. Condition reports have also been provided for review. On the basis of the information provided the forecast for this activity appears appropriate.

- Security enhancements are forecast as likely to result in an additional £4.0 m security enhancement expenditure. This is a relatively recent expenditure item with only a low historical expenditure being recorded. It is not clear if this is a blip or a sustained investment need. UUE has provided some information to support the forecast. However, the data could equally be interpreted as a transient issue. On that basis it appears that only a percentage of the forecast expenditure should be recognised.

A major expenditure item associated with Groundwater Regulations has been identified as driving a replacement need for fluid filled cables. UUE has identified in total £9.0 m for the replacement of fluid filled cables on environmental grounds. This includes replacement of 31 km of 33 kV cable and 8 km of 132 kV cable.

UUE has reported that it has undertaken full condition reports on the state of these assets and has discussed replacement with the Environmental Agency under Operating Code on 'Management of Fluid Filled Cables'. Table A7.2 below identifies the expenditure incurred in DPCR3.

Table A7.2: Fluid filled cable replacement in DPCR3

	2000/01	2001/02	2002/03*	2003/04	2004/05
Cable laid (km)		1.7	0.5	0.2	
Expenditure (£m)		3.8	2.1	1.0	

*Work in 2002/03 was 132 kV cable replacement. The remainder was 33 kV.

The forecast replacement during DPCR4 is around 5% of the fluid filled cable network.

A needs statement has been provided setting out the requirement to invest in underground cable replacement of fluid filled cables. UUE has also provided a list of the major fluid filled cables schemes that require investment. The activity listing is ranked in terms of priority and those that fall to be done in DPCR4 and DPCR5 have been identified and assessed as high risk. The expenditure profile for DPCR4 is set out in Table A7.3 below.

Table A7.3: Fluid filled cable expenditure profile

	2005/06	2006/07	2007/08	2008/09	2009/10	Total
Cable laid (km)	4 115	4 458	4 603	3 051	8 646	25
Expenditure (£m)	2.4	1.3	1.3	1.8	1.6	8.4

In total the proposals consist of 9.4 km of 132 kV and 15 km of 33 kV. This represents 3.6% of the total network assets for 132 kV. The percentage for 33 kV has not been possible to determine based on the information within the submission.

UUE has indicated that the option of replacing cable-joints no longer exists and that the replacement is based on cable replacement. It has not been possible to confirm this matter. The programme is front-end biased with the majority of the 132 kV being undertaken in years 1 and 2 of DPCR4. This phasing increases the probability of the scheme proceeding based on greater certainty of information.

No specific condition reports have been reviewed. However, the level of expenditure proposed in keeping with DPCR3 activity and in that regard may be considered as reflecting steady state replacement which given the percentage of the asset base affected does not appear unsupported.

A.8 Asset replacement

The following table sets out the expenditure included in the asset replacement category.

Table A8.1: Forecast capital expenditure associated with the asset replacement activity

Expenditure Classes	Non-Load Related (£m)					
	2006	2007	2008	2009	2010	Total
substations	27.1	27.1	27.1	27.1	27.1	**135.7**
overhead lines	17.7	17.7	17.7	17.7	17.7	**88.4**
underground cables	4.4	4.4	4.4	4.4	4.4	**22.2**
submarine cables	-	-	-	-	-	**-**
service lines and cables	2.7	2.7	2.7	2.7	2.7	**13.4**
meters	3.7	3.9	3.8	4.0	3.5	**18.9**
Tele-control / SCADA	3.0	3.0	2.3	2.1	1.8	**12.2**
Total	**58.6**	**58.9**	**58.1**	**58.0**	**57.2**	**290.8**

The programmes of work associated with overhead line and plant activity is set out below in Table A8.2 and Table A8.3.

Table A8.2: Overhead line and plant activity for DPCR4

DPCR4	2005/06	2006/07	2007/08	2008/09	2009/10	Total
Grid and Primary Circuits (km)	56	56	56	56	56	**280**
Grid and Primary Plant (no)	55	55	55	55	55	**275**
Secondary Network HV Circuits (km)	563	563	563	563	563	**2 815**
Secondary Network LV Circuits (km)	201	201	201	201	201	**1 005**
Secondary Network Plant (no)	583	583	583	583	583	**2 915**

Table A8.3: Overhead line and plant activity for DPCR3

DPCR3	2000/01	2001/02	2002/03	2003/04	2004/05	Total
Grid and Primary Circuits (km)	92	20	79	87	56	**334**
Grid and Primary Plant (no)	28	23	10	32	55	**148**
Secondary Network HV Circuits (km)	427	37	444	862	563	**2 333**
Secondary Network LV Circuits (km)	112	50	164	154	201	**681**
Secondary Network Plant (no)	1 148	818	2 283	2 898	583	**7 730**

Asset replacement associated with overhead lines is driven by CBRM as set out in UUE internal documents. The forecast of overhead line activity for DPCR4 is, post adjustment for 2002 Foot and Mouth Disease, broadly consistent with DPCR3 more so for HV line than LV line. This constant activity rate is as expected given that UUE operate on a fixed 15 year refurbishment cycle. This is broadly consistent with a total asset base of approximately 8 000 km HV and 5 200 km LV overhead line. On that basis the overhead line activity appears justified.

Secondary network plant replacement shows significant change between DPCR3 and 4. However, this volume count is slightly misleading given the different type of assets that may be included within the respective classifications. Grid and Primary network replacement is site specific and will be discussed later. Volume activity for DPCR3 compared to DPCR4 is set out in Table A8.4 below.

Table A8.4: Replacement volumes for DPCR3 compared to DPCR4

Units	DPCR3	DPCR4 FORECAST
132 kV Transformers	1	7
33 kV Transformers	21	38
HV Transformers	1 942	765
Transformer (no.)	1 964	810
132 kV Switchgear	28	50
33 kV Switchgear	67	85
EHV Switchgear	**95**	**135**
Switches	574	875
Ring Main Units	1 905	515
Circuit Breakers	420	730
A/Recloser & Section.	0	30
HV Switchgear	**2 899**	**2 150**
Pillars	796	220
Link Boxes	527	1 065
LV Switchgear	1 323	1 285
Total Switchgear (no.)	**4 317**	**3 570**
132 kV cables	9	7
33 kV cables	56	35
HV cables	320	190
LV cables	271	150
Under-ground Cable (km)	**656**	**382**
132 kV OHL	151	121
33 kV OHL	124	159
HV OHL	2 536	2 628
LV OHL	268	855
Overhead line (km)	**3 079**	**3 763**

Replacement volume forecasts between DPCR3 and DPCR4 overall tend to indicate a similar level of activity. With the exception of certain specific assets types:

- Link boxes;
- Ring Main Units;
- Circuit breakers;
- HV Transformers.

Changes in forecast volume for link boxes is explainable through UUE approach to forecasting end-of-life and probability of failure. This particular asset type has been subject to UUE's CBRM assessment. The forecast volume is therefore based on the revised forecasting methodology. Although the volume for this asset has increased the rational proposed appears robust.

The volume of Ring Main Units has reduced compared to DPCR3. UUE has indicated that this reduction is as a result of previous DPCR3 activity that focused on specific type replacement with operational issues, this accounted for 1506 units. That replacement need has now ceased.   On an equivalent basis, net of the safety driven replacement, the volume forecast to be replaced in DPCR4 increases by 116 units.

Overall the volumes forecast by UUE are less than those undertaken during DPCR3. This is driven by the outputs from UUE CBRM process. This will be discussed elsewhere in the report. However, while certain asset types may indicate an increase in activity this appears to be a consequence of a more focused and considered approach to asset management. Therefore, in total the secondary non-load related expenditure forecast appears from a volume perspective to be appropriate.

Table A8.5 below identifies the level of asset replacement expenditure forecast for the secondary network.

Table A8.5: Secondary network expenditure (excluding overhead lines) DPCR4

DPCR4	2005/06	2006/07	2007/08	2008/09	2009/10	Total
HV	(£m)	(£m)	(£m)	(£m)	(£m)	
Cable	2.2	2.2	2.2	2.2	2.2	**11**
Switchgear	8.4	8.4	8.4	8.4	8.4	**42**
Transformers	1.8	1.8	1.9	1.8	1.9	**9**
LV						
Cable	4.4	4.4	4.4	4.4	4.4	**22**
Switchgear	5.6	5.6	5.6	5.6	5.6	**28**
Total	**22.4**	**22.4**	**22.5**	**22.4**	**22.5**	**112**

DPCR3	2000/01	2001/02	2002/03	2003/04	2004/05	Total
HV	(£m)	(£m)	(£m)	(£m)	(£m)	
Cable	2.2	1	1.2	1.1	2.3	**8**
Switchgear	5.8	4.3	3.9	7.9	5.8	**28**
Transformers	3.4	1.8	1.4	1.3	1.3	**9**
LV						
Cable	9.8	3.1	5.9	1.8	2.5	**23**
Switchgear	4.2	7.8	6.7	9.1	5.2	**33**
Total	**25.4**	**18**	**19.1**	**21.2**	**17.1**	**101**

UUE has reported that cable replacement will be on a reactive basis. In terms of EHV and HV the replacement rate in the DPCR4 will reflect that undertaken in DPCR3. However, a reduction in HV cable replacement of 130 km can be observed from Table A8.5 above. This equates to a reduction in forecast expenditure of approximately £12 m within an overall increasing non-load related capital expenditure forecast.

LV cables have similarly been forecast based on DPCR3 replacement rate and fault trend. The level of replacement is forecast to be at a rate that maintains a constant fault level. This has resulted in a forecast of 120 km less in DPCR4 compared to DPCR3, this approximates to forecast reduction in capital expenditure for this item in the order of £7 m during DPC4. Consac replacement is assumed to represent the majority of the £1.7 m per annum expenditure. This appears consistent with information provided as part of the HBPQ.

No allowance for Lane Rental cost has been made within either non-load or load related. However it has indicated that it would expect Ofgem to recognise this position if Lane Rental charges were to be imposed.

The approach to cable replacement of reactive based on DPCR3 activity and fault rate is appropriate and hence supported. The volume forecast by UUE has been accepted as that needed to achieve that aim. As a consequence 250 km less of HV and LV cable will be replaced delivering a potential saving in DPCR4 in the order of £19 m.

The variation between DPCR3 and DPCR4 cable volumes has been reconciled with the volume installed and accounted under diversion activity; Whereas, DPCR3 includes diversion activity DPCR4 is purely replacement. In addition DPCR3 included a greater degree of under-grounding associated with overhead line programme than is allowed for in DPCR4. The issue of diversion related activity requires confirmation, as does the volume associated with overhead line under-grounding.

Disaggregation of the secondary expenditure by cable, switchgear and transformer indicated in Table A8.5 above provides transparency associated with the main asset classes. The main contributor to DPCR4 has arisen as a consequence of HV switchgear. Reference to Table A8.4 above ‘Replacement volumes DPCR3 – DPCR4’ indicates that an additional £12m is forecast to arise as a consequence of additional activity associated with switches, circuit breakers and ring main units. Based on the forecast volume variance multiplied by an average unit cost tends to support the level of increase observed. On that basis the level of forecast expenditure for this activity appears justified.

UUE has not split secondary and primary expenditure in its submission. It has however identified separately that primary expenditure contributes a £2.0m positive variance compared to DPCR3. Table A8.6 identifies the main asset classes that contribute to that increase. Cable replacement expenditure in Table A8.6 in total during DPCR3 is reported at £16m. In DPCR4 this is forecast to be £4m. A further £9m is reported as needing replacement in order to comply with environmental requirements, discussed earlier. In total the level of expenditure required for provision of primary cable is slightly less in DPCR4 when compared to that projected for DPCr3. The main driver for the forecast cable expenditure is environmental compliance. Comments have already been made on this issue and in general supported the need for replacement. The model output for this specific element is broadly in keeping with the total primary cable expenditure level submitted by UUE.

Table A8.6: Primary network expenditure (excluding overhead lines) DPCR4

	2000/01	2001/02	2002/03	2003/04	2004/05	Total
132kV						
Cable	1.1	1.4	0.6	1.9	0.9	**5.9**
Switchgear	3.7	3.3	2.4	5.4	4.5	**19.3**
Transformers	1.2	0.8	0.9	1	0.8	**4.7**
33kV						
Cable	2.1	1.9	1.6	2.7	1.8	**10.1**
Switchgear	0.6	0.4	0.7	0.5	2.4	**4.6**
Transformers	2.2	0.9	1.4	0.8	1.9	**7.2**
Total	**10.9**	**8.7**	**7.6**	**12.3**	**12.3**	**51.8**

	2005/06	2006/07	2007/08	2008/09	2009/10	Total
132kV						
Cable	0.4	0.4	0.4	0.4	0.4	**2**
Switchgear	4.8	4.8	4.8	4.8	4.8	**24**
Transformers	1	1	1	1	1	**5**
33kV						
Cable	0.4	0.4	0.4	0.4	0.4	**2**
Switchgear	1.5	1.5	1.5	1.5	1.5	**7.5**
Transformers	2.6	2.7	2.6	2.7	2.6	**13.2**
Total	**10.7**	**10.8**	**10.7**	**10.8**	**10.7**	**53.7**

A.9 Review of scheme papers

A review of non-load related expenditure scheme papers has been undertaken. The papers reviewed were randomly selected from a list of schemes provided by UUE. The outcome of that review is detailed below:

- Westlington – Spadeadam 33kV Line: This line was inspected in 1996 with recommendation to review in 2007. The line is classed as 'at-risk' and is regarded as high priority. Although the condition report has not been provided summary information has. From that information the decision to review in 2007 appears appropriate. However, there is no certainty that this will identify a replacement need. On balance based on the detail provide and it's the next inspection date suggests that this scheme has a medium probability of proceeding in this review. There is justification to conclude that if the scheme does not proceed in DPCR4 that investment will be required in DPCR5.

- Padiham switchgear replacement: A summary condition assessment report has been provided. This project is tied to NGT replacement at that site. UUE have reported that NGT are proposing outages towards the end period of DPCR4. Based on the detail provided and the timing of this replacement activity raises concern that it may not be undertaken in

DPCR4. On that basis this is regarded as having a medium probability of proceeding.

- Harker 132kV Substation Replacement. Insufficient information provided upon which to base an opinion.

- Queens Park substation transformer replacement: Insufficient information provided upon which to base an opinion.

- Bolton substation transformer replacement: Insufficient information provided upon which to base an opinion. The general wording tends to suggest that replacement is not justified.

- Griffen substation circuit breaker replacement: This activity is part of as broader replacement programme associated with Reyrolle L42T 33kV circuit Breakers. This programme is reported as £8.2m in total. These units are performing poorly and this view tends to accord with our own. This expenditure appears to have a high probability of proceeding.

Concern exists following this scheme review exercise. The scheme papers were chosen at random and varied in terms of forecast replacement timescale and value. The information provided contained only limited information. If the asset replacement proposed by UUE had been substantially different to that undertaken during DPCR3 or had the submission not been as transparent in identifying the need and level of investment required or had the meetings and subsequent data requests not bolstered confidence that the company has assessed, understood and compiled a credible submission then it would be difficult to support the forecast level of non-load replacement capital expenditure. However this is not the case. It is appreciated, that given the value of some schemes chosen as well as the planning time horizon that the level of uncertainty that may exist is high. Such uncertainty being driven by the many variables that exist that may well result in a change in project scope and final delivery.. Non-load metering expenditure forecast by UUE is significantly less than other DNOs of a comparable size. The reason for this reduction is based on UUE perceived loss of market share to Meter Operators already established in the UUE licensed area. This has resulted in a relatively high average unit cost associated with statutory meter changes. UUE has advised that the average unit cost is relatively high given the stranded costs associated operating a metering business on a low volume of activity.

A.10 Forecasting methodology

UUE are differentiated from other industry players in this activity. Where as most other DNOs adopt asset replacement profiling, to varying degrees, to inform long-term forecasting supported by condition assessment for short-term programmes UUE has moved towards a forecasting methodology based on Health Indexing. This approach is built on condition reports reconciled to end-of-life assessments and fault trends. As a consequence of this approach forecast replacement volumes are, for some asset classes, at variance to those in DPCR3 or those that may be derived from replacement profiles. The health Indexing methodology is, in the UK, a relatively new concept and to that end UUE is at the forefront with regard to its acceptance and implementation. Other DNOs are reviewing the process and are some are adopting the approach. Health Indexing is reliant on data and the extent to which end-of-life or probability to failure can be accurately predicted. The extent to which data sensitivities and end-of-life classification impact on forecast volumes requires further assessment.

However, it is our view, based on the information provided, that the process is rigorous and provides a mechanism to reconcile short-term and long-term forecasting to actual activity and change in perceived risk profile. At present, a concern does exist with regard to sensitivity of the output and robustness of probability-of-failure mathematical functions.

UUE has undertaken CBRM on the majority of its asset base and has provided information to identify those assets considered.

The issue of overlap between non-load related and load-related expenditure has been reviewed. We are satisfied that for site specific primary schemes that such overlap can easily be avoided given the visibility of site-specific schemes. In terms of secondary expenditure visibility between asset replacement for condition or reinforcement reasons is not so transparent. However, UUE has identified that adjustment to the non-load related forecast is undertaken and has identified that degree of adjustment. While it has not been possible to verify in detail the derivation of such an adjustment, nor have we verified its application, we are of the opinion that the adjustment appears an appropriate allowance.

A.11 Work programmes

UUE has not provided a detailed work programme but has identified that the programme of works is forecast for secondary assets on a relatively flat basis through DPCR4. Grid and primary expenditure is forecast on a site-specific basis. A schedule of the site-specific schemes relating to asset replacement s set out in table A11.1.

Table A11.1: Grid and primary expenditure during DPCR4

			2005/6	**2006/7**	**2007/8**	**2008/9**	**2009/10**	**Total**
Voltage Group	**Expenditure Category**	**Asset Investment Category**	(£k)	(£k)	(£k)	(£k)	(£k)	(£k)
Primary		Circuits (Cable)	364	364	364	364	364	1820
Grid		Circuits (Cable)	364	364	364	364	364	1820
		Circuits (Cable)	**728**	**728**	**728**	**728**	**728**	**3640**
Primary		Circuits (OH)	420	1355	712	645	353	3485
Grid		Circuits (OH)	4234	6812	6849	7112	6588	31565
		Circuits (OH)	**4654**	**8167**	**7561**	**7757**	**6941**	**35050**
Primary		Plant (Switchgear)	47	3208	1853	2347	1109	8564
Grid		Plant (Switchgear)	6000	3916	4421	4939	3592	22868
		Plant (Switchgear)	**6047**	**7124**	**6274**	**7286**	**4701**	**31432**
Primary		Plant (Transformers)	150	4772	4046	2331	713	12012
Grid		Plant (Transformers)	1390	1960	2070	500	500	6420
		Plant (Transformers)	**1540**	**6732**	**6116**	**2831**	**1213**	**18432**
		TOTAL	**12969**	**22751**	**20679**	**18602**	**13583**	**88554**

APPENDIX B

QUALITY OF SUPPLY SCENARIOS

APPENDIX B – QUALITY OF SUPPLY SCENARIOS

B.1 Network performance improvements

UUE's approach to the modelling of QoS initiatives is robust and well supported in terms of data and systems.

UUE has proposed a programme for improvement in quality of supply of some £17.2 m. This is mainly associated with further remote control and automation, fitting of protection and retrofit of asset control mechanisms. These two initiatives, as shown in table B.1, account for £13.6 m of the overall expenditure forecast. Installation of remote control and automation devices will result in a degree of network reconfiguration in terms of ability to increase network sectionalisation. UUE's approach has been to assess and rank options in terms of optimum cost-benefit delivery.

Table B.1: QoS initiatives

Quality of Supply Initiative	**Cost (£m)**
38 HV Primary CB Hand charged spring replacements	0.2
Remote Control and Automation (RC&A) of Normal Open Points (NOPs) at 13 Single Transformer Primary S/Ss	0.5
RC&A of 130 worst performing HV circuits	9.1
29 33kV Delayed Auto-Reclose schemes	1.4
Replacement of Hand Reset Relays and modifications to Standby EF Relays at 300 sites	4.5
RC&A of 22 HV circuits with > 2500 customers	1.5
TOTAL	**17.2**

UUE has identified that an additional 130 circuits over the 350 circuits forecast to be installed in DPCR3 will be undertaken. Each circuit is ranked in terms of its cost: benefit value.

UUE has approached the +/-2% scenario based principally on increment or decrement of the initiatives identified in the main QoS improvement scenario. The additional cost for a +2% improvement in CI is forecast to be an additional £7.6 m. This is delivered primarily through remote control and automation. This is reported to provide 2.1% improvement to CML and appears an appropriate initiative to consider.

The 5% improvement in CML is delivered through additional remote control and automation building on the base QoS initiative. The additional cost is £34.2 m. While this is a relatively low cost option the decrease in cost: benefit ratio suggests that the initiative may be reaching its limit in terms of application. However, overall the initiative does provide substantial customer benefit with both increases in CML and CI. The CI increase is forecast to be 5.6%.

UUE has forecast a reduction in forecast capital expenditure associated with a 2% CI deterioration of £5.6 m with an associated 1.6% CML loss. A 5% CML deterioration results in a saving of £13.5 m. This saving is delivered by reducing the activity associated with remote control and automation as well as reduction in the Hand Reset Relays and modifications to protection devices. The 5% CML deterioration also results in a 10% CI reduction. Whilst this does deliver the CML reduction specified it also impacts on CI performance.

The main initiative across all scenarios is mainly that of remote control and automation. The approach taken by UUE to assessing and ranking of these initiative and constituent projects, as well as the flexibility of the main initiative, has resulted in a simple but accurate means of forecasting delivery CI and CML parameters. While no detailed assessment of cost or performance has been considered the basis upon which UUE undertake its analysis supports the forecast. In that regard, the forecast appears, based on the information and depth of analysis undertaken, to be reasonable.

B.2 Resilience undergrounding

UUE has identified two options associated with accelerated overhead-line upgrade. Option 1 is forecast at £274.5 m. Option 2 is reported at £52.6 m. Both of these options involve increase network resilience through application of EATS 43-40 design standards. The variation between the two options relates to the delivery date for completion of the proposal. The unit costs provided are those in Base Case submission. The level of the unit cost requires further consideration.

In terms of volume UUE has identified 7 407 km of HV line and 663 km of 33 kV. UUE has assumed a linear installation profile for both HV and EHV. Until more detail becomes available this appears a pragmatic view. Given the current refurbishment policy is based on a standard run rate per annum then line upgrade would be expected to follow a similar trend. In terms of cost then while UUE has used the Base Case unit costs consideration may need to be given to access of overhead line service providers. This supply and demand issue may well increase the unit cost for delivery. This factor has been identified by UUE and appears a valid statement. However, extent of the increase may require further consideration. UUE does undertake a small percentage of EATS 43 - 40 through its normal refurbishment policy. This double-count has been considered in this scenario. UUE has identified the risk to existing overhead line consent of pursuing a delivery date of 2010. As such, it does not believe that this is a credible proposal, based on the information provide and volume forecast this comment appears appropriate.

In terms of quality of supply improvements UUE has estimated the CI and CML saving. No comment is made on the numbers reported.

Improved network resilience through under-grounding has been modelled based on 2% of all voltages; Option 1, or only 2% of total overhead network targeted at HV overhead line, that is 3.44% of the HV system; Option 2. The expenditure forecast is 74.2 m or 3.9 m respectively. The unit costs provided are those in the Base Case submission uplifted by 210% to compensate for routes and ground-mounted switchgear. UUE has indicated that since such a programme would most likely be targeted at HV overhead lines that are non 43-40 compliant then Option 2 is most likely. This view appears to be appropriate..

In terms of quality of supply improvements UUE has estimated the CI and CML saving. No comment is made on the numbers reported.

UUE has identified the volume of overhead line within AONB or National Parks. This volume is set out in Table B.2 below:

Table B.2: Overhead line by voltage within AONB or National Park areas

	132kV circuit	132kV route	33kV	11kV	6.6kV	415V	240V	Total
National Parks								
Lake District	115	61	113	1127		111	125	**1536**
Yorkshire Dales			16	246		20	22	**303**
Northumberland				9		1	0	**10**
Peak District			6	213		38	23	**280**
AONBs								
Northern Pennines			15	191		14	29	**249**
Arnside and Silverdale			9	48		16	14	**88**
Solway Coast			5	71		8	8	**92**
Forest of Bowland			34	458	64	39	72	**667**
Total	**115**	**61**	**198**	**2363**	**64**	**246**	**293**	**3224**

Under grounding for amenity value is forecast by UUE as likely to require investment in the order of £1.1 bn. This is based upon under-grounding across all voltage levels as set out in Table B2. Given the type of area and ground condition the unit cost provided in UUE's Base Case has been uplifted by 410% for National Park areas and 210% for non-National Park or AONB areas. While it is recognised that any costs increase due to routes, switchgear replacement and additional wayleaves may exist no exercise has been undertaken to verify the assumptions made by UUE.

In terms of quality of supply improvements UUE has estimated the CI and CML saving. No comment is made on the numbers reported.

APPENDIX C

DNO ALTERNATIVE SCENARIO

APPENDIX C – DNO ALTERNATIVE SCENARIO

C.1 DNO alternative case

The DNO scenario includes £106 m gross or £62m net for expenditure as a consequence of Distributed Generation. This is reported to be driven by the need to replace certain switchgear due to over stressing. Switchgear driven through additional fault in-feed and voltage control problems are identifiable issues associated with a high penetration of distributed generation, along with amendments to existing SCADA and network control. No exercise has been taken to investigate further the information presented by UUE in this area.

APPENDIX D

LOAD RELATED EXPENDITURE MODELLING

APPENDIX D – LOAD RELATED EXPENDITURE MODELLING

The methodology used in the modelling of the companies forecast for load related expenditure is based on 3 discreet steps:

- a review of the main investment drivers, growth in customer numbers and units distributed (GWh) over the period to be reviewed;
- a comparison of LRE outturns and projections using Modern Equivalent Asset (MEA) values of the companies total network assets and, finally,
- a benchmarking of the relative evolution of each company's LRE against the those of the rest of the companies which included a representation of relative efficiencies and provides an implicit 'Industry view' on the evolution of LRE.

These issues are further discussed below and consideration is given to the period over which the analysis was carried out. Flow charts for the process showing the derivation and combination of the MEAV/Customer and MEAV/GWh factors are included in the Appendix.

D.1.1 Stage 1: Review of growth in customer numbers and Units distributed (GWh)

Load related expenditure is affected by two main drivers, customer connections and demand growth, which underpin the majority of the companies' expenditure forecast associated with the New Business and Reinforcement categories respectively. The importance of these variables on the LRE has been reflected by the companies, many of which receive regular specialist advice for forecasting main economic trends in their distribution area. These forecasts have been presented as supporting evidence for the companies' own projections. The companies have assessed the impact of the overall trends and other external factors beyond their control upon customer connections and demand growth in their elaboration of the projected LRE for DPCR4.

The first stage of the review process was therefore to examine the historical evolution of customer and demand growth and its comparison with the company expenditure projections for the next control period and to make adjustments for modelling purposes as necessary.

D.1.1.1 Analysis of demand growth

The companies were asked to submit outturns and forecasts for regulated distributed units at different voltage levels and peak demand including weather corrected (Average Cold Spell, ACS) peak system demand.

Demand growth can be used as a proxy for the overall level of economic activity, which drives new business spend, and is also an indicator of the need to reinforce the system. The data regarding energy growth is comprehensive since it is associated with the Ofgem formula set for the calculation of the regulated revenue of the companies at the start of the present control. Units distributed are generally considered to be a more robust indicator of growth than Maximum Demand.

EHV units are associated with a small number of large customers and are therefore subject to the volatility associated with the activity of a small number of users that, in turn, may have a distorting effect on the observed variability of the company total distributed units. In order to enable a more consistent comparison, the demand growth of HV/LV units only was adopted as an indicator of demand growth.

In order to form an independent view of future demand growth, a review of the comparability between units distributed and a macro-economic indicator (gross value added, GVA) was carried out for each DNO. This analysis is described fully in Appendix E.

Where trend analysis and the independent GVA based view of forecast growth both showed that DNO forecast GWh growth was either higher or lower than anticipated, then the forecast was adjusted by the minimum necessary to match either the trend analysis or the GVA based forecast.

D.1.1.2 Analysis of new customers

There are large fluctuations in reported customer numbers due largely to changes in reporting following the opening of the retail market (and introduction of Meter Point Administration Numbers in about 1998) and the improvements in customer connectivity reporting under the Information and Incentives Project (IIP) in about 2002. The net effect of these fluctuations is to cause a step increase or decrease in the total number of customers connected to the network. For modelling purposes, we consider it necessary to remove such step changes to reflect the true growth in customer numbers. Profiling the customer numbers before and after the fluctuations and shifting the pre-fluctuation profile to align with the post fluctuation profile achieved this.

Where trend analysis showed that the forecast growth in customer numbers was out of step with historic growth, customer numbers were adjusted accordingly. This was considered particularly appropriate for load related modelling since investment normally lags growth by two to three years and any change in growth in the later years of the review period should not influence the investment required in the period.

D.1.2 Stage 2: Benchmarking of LRE using MEA network values

The companies' networks are a reflection of the particular circumstances affecting their areas of supply. These circumstances include not only physical factors, such as geographical location, customer density etc., but also other effects such as company historical design policies, operating practices etc. All these have been historically been built into the existing network and amount to an average network cost per customer which is then specific to each company. As new customers are connected, it can be expected that the additional cost per new customer, over a reasonable period, should approximate to the Modern Equivalent Asset Value (MEA) of the entire network per existing customer. In so doing, the effects of load density or high location-related costs such as underground networks in congested areas are taken into account.

The proposed MEA method is also robust regarding network design policy since all companies work against a common security standard with variations in LPN and SHEPD for network reinforcement. The companies' submissions indicate that the network design does not vary significantly from the requirements embodied in the Licence Security Standard and hence network MEA provides a consistent basis for comparison of the companies.

The procedure followed in the calculation of MEA builds on the information used in the analysis of Non-Load Related expenditure. As part of the Non-Load Related submission the companies were asked to provide age profiles of all the main network assets and a cost database for all the main categories of equipment. The cost data submitted by all the companies was used to inform our own "PBP Cost Database' in order to arrive at an aggregate DNO view of cost levels. Modern Equivalent Asset (MEA) value of the companies' networks was then obtained by cross-multiplying the cost database and the assets database. The results so obtained for the analyses of the LRE are therefore consistent with the figures used in the analysis of NLRE. In order to eliminate distorting variables from the analysis, Generation expenditure is removed from the analysis.

Future expenditure is therefore assessed on a cost per new customer and GWh added compared to MEAV per existing customer and GWh distributed (referred to as the 'Combined Model'); this not only assesses future expenditure compared to past expenditure on a DNO basis but it allows comparisons between companies to be made.

D.1.3 Stage 3: Inter-companies benchmarking of LRE projections

The companies forecast of LRE weighted by their relative MEA per customer as indicated above can be benchmarked among the companies using the "prevalent" industry trend. In the analysis undertaken, the prevalent industry trend has been represented by using the median figure in order to arrive at appropriate factors for all the companies. This benchmarking approach is also consistent with the method adopted in the analysis of NLRE.

The overall trend resulted in MEA value per customer below unity. This indicates than on the whole the companies expect to spend on average during the next control period below what they would have spent historically and is justified on the efficiencies already achieved and forecast into the next period. The lower than unity MEA value per customer also tends to indicate the marginal costs of extending an already mature network. These efficiencies are expected to come from procurement, design and better asset utilisation via greater use of network knowledge relating to demand distribution variations over time, plant loading and system risks. Some companies have planned on reductions in their New Business spend through the loss of a significant proportion of new connections business over the next period which has been duly accounted for in the models in respect of forecast expenditure.

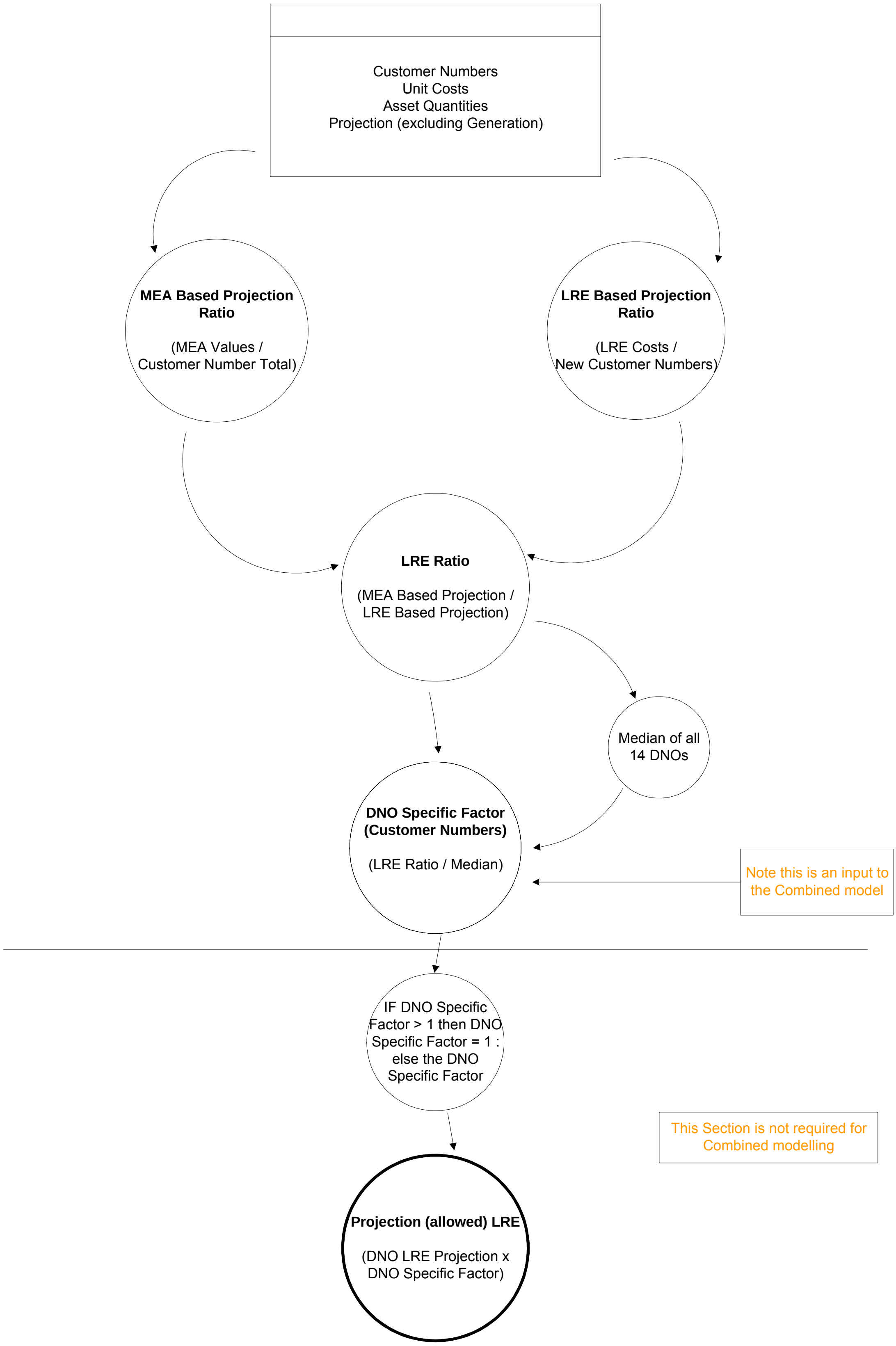
Being benchmarked on a median rather than on an average implies that extremes do not affect the adopted benchmarking position. It also means that the LRE of each company is compared relative to its cost base against the Industry Trend and not in absolute cost terms. This approach recognises therefore the historic cost of distribution within the area of influence of each company and, at the same time, requires the company to drive their costs down in accordance with the prevalent industry trend. In this respect and similarly to the case of Non-Load related expenditure PB Power's view is impartial in that it is the Industry that ultimately sets the trend by which all the companies are measured.

D.1.4 Period of analysis

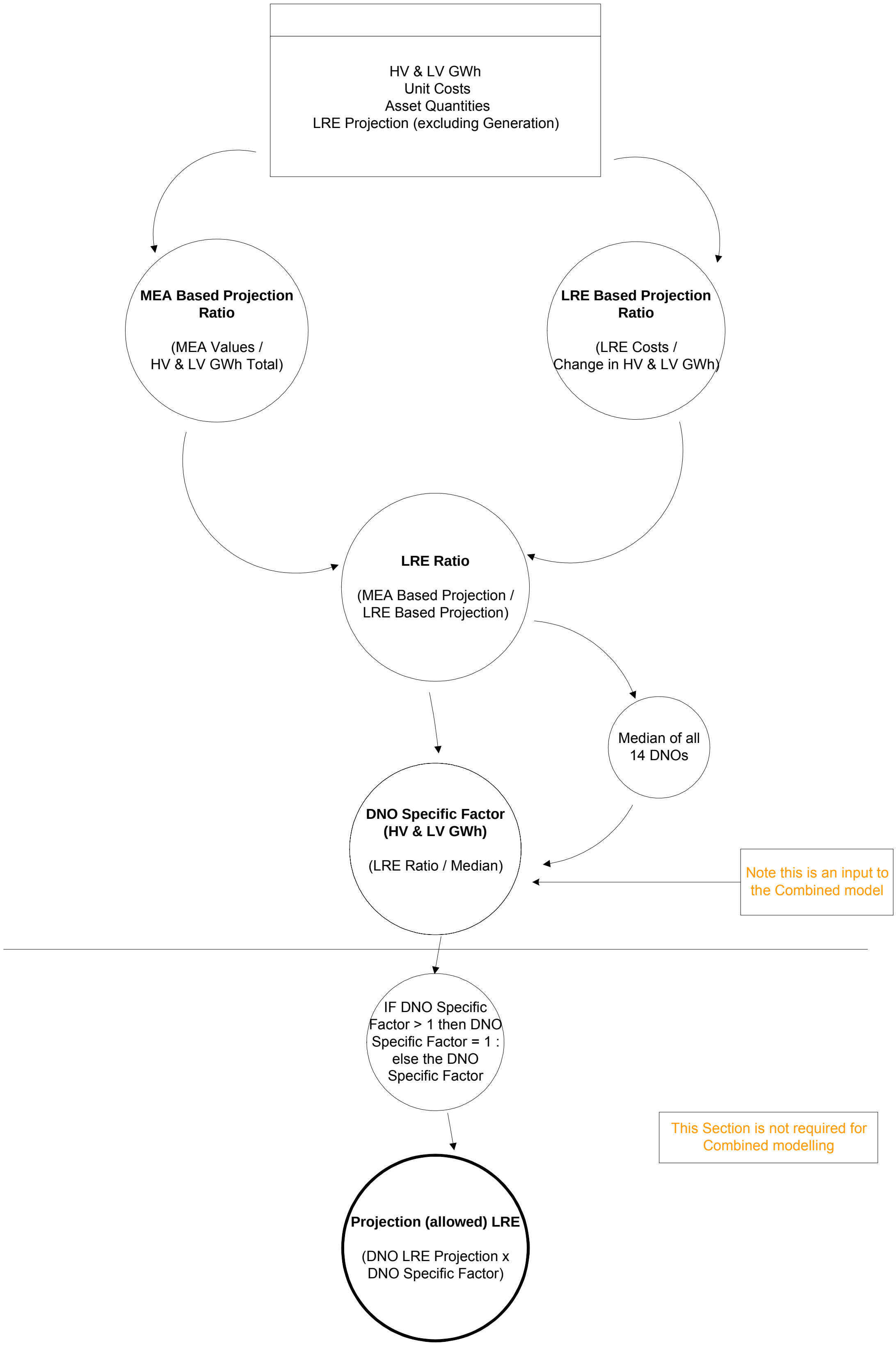
Although each DNO's network is comprised of a large number of smaller networks and that it would be expected that these would have a range of spare capacities depending on local load growth and when individual networks were last reinforced, it is possible that a larger number of the smaller networks would require reinforcement within one regulatory period and fewer in a subsequent period and hence cause a peak in expenditure in one period rather than another.

This issue can be addressed by modelling the expenditure required over a number of review periods and assessing future expenditure requirements by taking into consideration the expenditure already incurred in previous review periods. The modelling carried out in the current review therefore looked at growth and expenditure over DPCR2 and DPCR3 in addition to the forecast growth and expenditure for DPCR4.

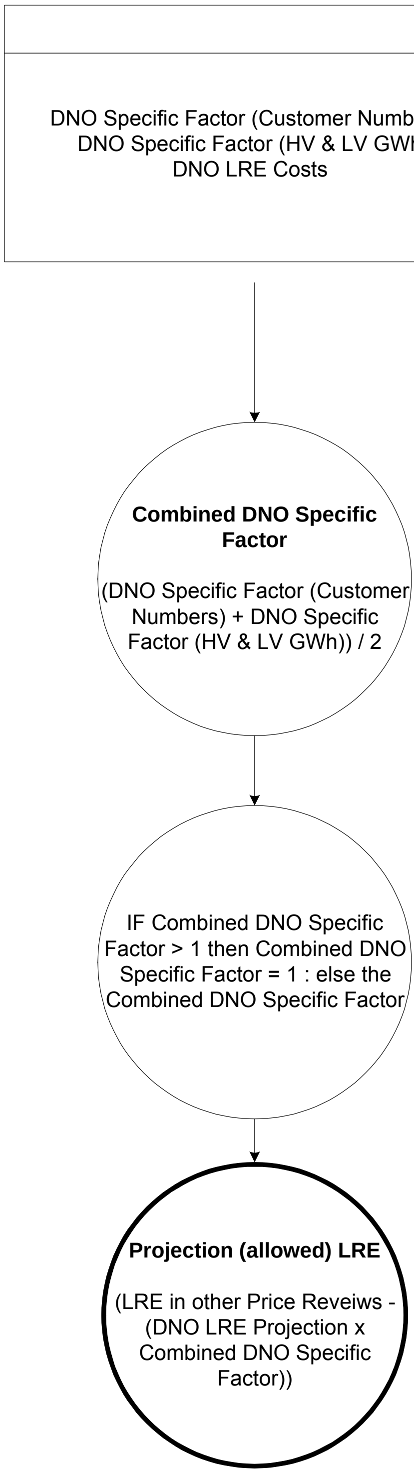
Combined Load Related Expenditure Modelling (Phase 1A Customer Numbers)



Combined Load Related Expenditure Modelling (Phase 1B Load Forecast HV & LV GWh)



Combined Load Related Expenditure Modeling (Phase 2 Customer Numbers & Load Forecast)



APPENDIX E

DEMAND GROWTH ANALYSIS

APPENDIX E - DEMAND GROWTH ANALYSIS

E.1 Introduction

The purpose of the review of the load forecasts provided by the DNOs in their HBPQ and FBPQ submissions is to review the consistency of the load forecasts as a comparator for load-related modelling. Three candidate data sets for comparison purposes were provided as part of the key performance indicators (KPIs), namely customer numbers (by voltage), energy or units distributed (GWh, by voltage) and system power demand (MW). A review was subsequently made of the comparability between units distributed and a macro-economic indicator (gross value added, GVA). Only HV and LV units distributed were considered as the trend in EHV units exhibited volatility, often due to changes (reductions) in manufacturing output.

Although strictly power demand should be the direct capacity driver, energy trends are generally considered to provide a more consistent long-term indicator of load growth. System maximum power demand occurs at a single instant and may vary year on year, although maximum demand data is corrected for weather (average cold spell – ACS correction). Energy is however integrated over time and less prone to instantaneous influences. In this case a simple check was also carried out to show that the change in load factor was not a significant issue.

Customer numbers were declared by voltage level, but not by sector (domestic, commercial and industrial) and some of the DNOs stated that since the separation of distribution and supply businesses such (traditional) disaggregation of load data is no longer available to them. (A similar comment has been made by NGC in the 2002 and 2003 editions of its Seven Year Statement.) Consequently a comparison between, say, new housing starts and net increase in LV customer numbers was not possible without disproportionate effort in this instance.

Furthermore discontinuities were found in DNOs' declarations of customer numbers due to changes in reporting following the opening of the retail market (and introduction of MPAN numbers in about 1998) and the improvements in customer connectivity reporting under the Information and Incentives Project (IIP) in about 2002. These discontinuities particularly affected the calculation of net increases in customer numbers. (For analysis purposes a method of deriving a smoothed projection was subsequently derived and is described in the main text of this report.)

As GVA data was more readily available in a form that could be analysed and as units distributed were viewed as a more consistent comparator than customer numbers, the review of load forecasts was confined to a comparison of increases in units distributed with GVA.

E.2 Gross value added (GVA)

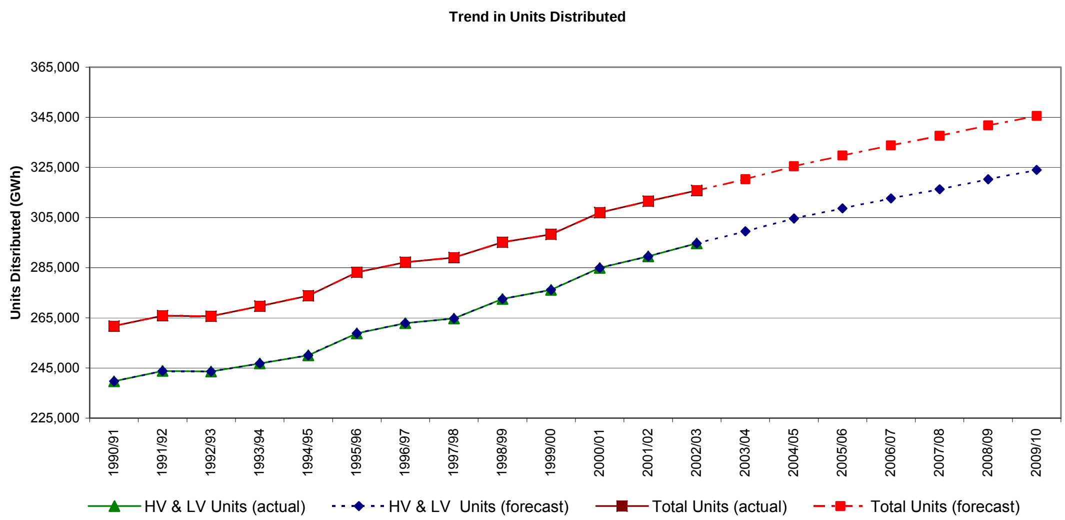
For the purposes of this review, GVA is treated as being synonymous with gross domestic product (GDP). Furthermore Regional Accounts are currently published in terms of GVA[1] only. Statistics are published by geographical region in accordance with the Nomenclature of Units for Territorial Statistics (NUTS) classification. NUTS1 covers regions, NUTS2 covers sub-regions and NUTS3 covers unitary authorities or districts. At present NUTS2 data is available for the years 1995 to 2001 and NUTS3 data for 1993 to 1998 only.

In the review NUTS2 headline GVA data on a sub-regional basis was reconfigured to reflect the corresponding GVA per DNO service area. For example the NEDL area GVA was derived as comprising the North East Region and North Yorkshire (part of the Yorkshire and the Humber Region). In other instances where a more detailed disaggregation was required, NUTS3 data was used to indicate the proportioning of GVA by district (for example the disaggregation of Welsh GVA into SP Manweb and WPD South Wales distribution service areas).

As GVAs are published at current basic prices, the GVAs were brought onto a common 2002/03 price basis using the indices in the RP02 "All Items" index.

E.3 Trend of energy distributed against time

The trend of energy distributed against time is presented in the chart below.



The total regulated units are HV and LV units and the total regulated units include EHV units. Up to and including 2003/03, the units distributed are actual units whereas from 2003/04 onwards these are forecast.

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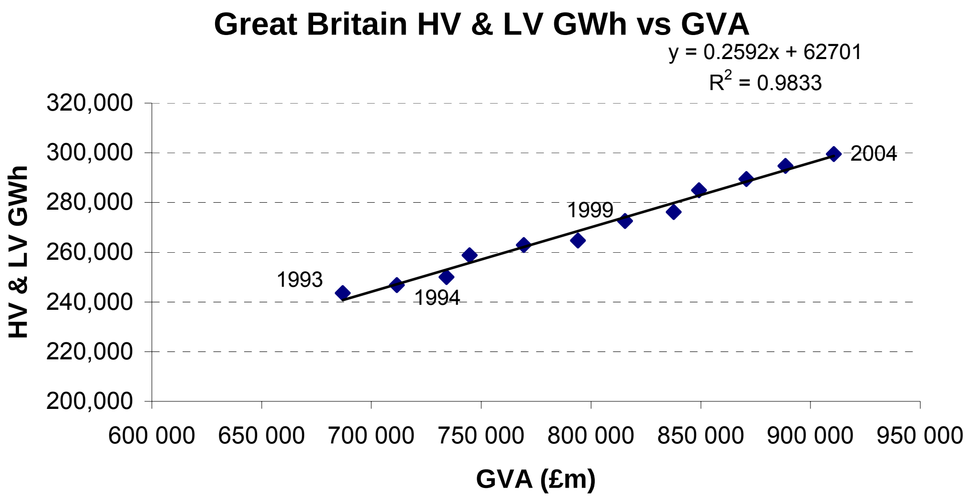
[1] Office of National Statistics: Local area and sub-regional gross domestic product, 26 April 2001, www.statistics.gov.uk

The average annual load growth of both total and combined HV and LV units from 2004/5 to 2009/10 is about 1.2 per cent nationally.

E.4 Historic trend of units distributed against GVA

The trend of HV and LV units distributed against GVA in Great Britain is presented in the chart below and shows a good correlation[2].



A comparison was also made between the percentage increases in units distributed (%ΔGWh) and (%ΔGVA). The national (Great Britain) average of %ΔGWh/%ΔGVA covering the years 1995/96 to 2001/02 (years of NUTS2 data availability) is about 0.7. Typical corresponding values for DNOs were calculated to be in the range of about 0.5 to 0.9.

E.5 GVA growth rates

Growth rates for GVA nationally for the years 2002/03 to and 2003/04 were obtained from ONS GDP statistics. By region a variety of published sources was used, including regional assemblies, regional development agencies and prominent econometric consultants.

For the years 2004/05 onwards, the HM Treasury “Forecasts for the UK Economy” dated February 2004[3] was used as the forecast for national growth. In a number of cases and, depending on the availability of published data, regional growth trends were estimated from the national trend but with a difference applied depending on the relative positions in 2003/2004.

[2] To align GVA and GWh data, ONS data for 2001 was treated as corresponding to the review year 2001/02 and so on.

[3] www.hm-treasury.gov.uk/media//E7910/ACF11CB.pdf, "Forecasts for the UK Economy", February 2004.

FORECAST UK ANNUAL CHANGE IN GDP (GVA)
(%)

2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
1.7	2.1	2.8	2.6	2.5	2.5	2.3	2.3

As might be expected the highest forecast growth rates are in London and the South East. The lowest are in the North East of England and in Scotland. The underlying driver in the forecast growth is the service industry.

E.6 Derivation of GVA-based load forecasts

Forecasts of GVAs up to 2009/10 for each DNO service area were obtained by applying the forecast growth rates to the 2001/02 GVA data derived from the NUTS2 sub-regional GVA data referred to earlier.

For each of the years 1995 to 2001 and for each DNO, a plot was made of HV and LV units distributed against corresponding GVA and a linear “least squares fit” regression line applied. For 12 of the DNOs a good correlation (R-squared value > 0.8) was obtained. The remaining two DNOs showed R-squared values of about 0.6 and 0.7 respectively, reflecting year-on-year variations in units distributed.

The regression formulae for GWh versus GVA were applied to the forecast GVAs in order to obtain GVA-based forecasts of units distributed for each DNO. The individual forecasts for DPCR4 were adjusted pro rata so that the overall increase nationally was equal to that forecast by the DNOs.

APPENDIX F

NON-LOAD RELATED CAPEX MODELLING

APPENDIX F – NON-LOAD RELATED CAPEX MODELLING

F.1 NLRE Asset Replacement Modelling for DPCR4

The NLRE that is modelled is that concerned with asset replacement and refurbishment, as charged against capital expenditure. The asset replacement modelling procedure and associated assumptions adopted for DPCR4 are described in this Appendix and are consistent with those discussed with DNOs during the course of the review. The input data used is, in the main, based on that provided by DNOs as part of the DPCR4 FBPQ process. Where PB Power has had need to supplement the DNO input data, such as the process of deriving a industry weighted average replacement profiles or use of PB Power's own replacement unit costs, then such actions have been highlighted.

F.1.1.1 Age-based replacement

A modelling technique has been employed for all switchgear, transformer, underground cable, submarine cable and overhead line asset types, with detailed variations as appropriate. This technique is equivalent to the "survivor" type analysis that formed the main input into DPCR3 non-load replacement modelling.

Fundamentally the model requires three input data items for each defined asset category, viz:

i. age profile

ii. retirement profile and

iii. unit cost.

The age profile defines the number of assets still in service and the current age of those assets.

The retirement profile represents the ages at which assets are retired from the system. These profiles are generally expressed as the fraction of assets that would be expected to be retired in each year over a given number of years of operation. For DPCR4 the retirement profiles have been based on Gaussian distributions defined according to the standard deviation and mean life of the asset types represented. As part of the modelling process we have derived industry weighted average replacement profiles for each asset type. These are normal distributions with mean asset lives obtained by weighting each DNO's expected useful life for the asset by the corresponding DNO asset population.

The unit costs are the replacement costs for items new plant and equipment on a per unit basis namely per transformer, per switchgear bay and per kilometre of underground cable. The schedule of PB Power's unit costs is presented in Appendix G.

The asset replacement calculation involves the cross-multiplication of the estimated original population of the assets of a given age with the assumed retirement fraction for assets of the same age. This process is carried out for assets of all ages such that the output of the model represents the total volume of assets to be replaced. The asset volume is then multiplied by the appropriate unit replacement cost to give an estimate of the replacement expenditure for that asset type.

Our modelling of asset replacement and refurbishment concerns non-fault replacement and refurbishment; DNOs have been required to segregate fault and non-fault expenditure and the former may be considered as operating expenditure. Discussion with DNOs has been held on the issue of overlap between assets replaced due to fault and those replaced as a consequence of other asset management drivers. Given that these areas are modelled separately it is important that the risk of double counting is reduced. In terms of transformer replacement it has been decided that, in general, replacement of pole-mounted transformers occur mainly as a result of a fault. Therefore, no pole-mounted transformers have been included in the modelled output of (non-fault) expenditure. The majority of cable replacement tends to be undertaken due to fault. Nevertheless DNOs have classified a certain volume of cable replacement as non-fault replacement . It is this non-fault replacement activity that is considered and hence included in the modelled output

F.1.1.2 Cyclic refurbishment / replacement

We investigated the direct modelling of refurbishment and replacement of overhead lines on a cyclic basis and found that it was not sufficiently robust in volumetric terms to reflect the refurbishment activity over a five-year period (DPCR4). Instead we found that replacement profile approach using an adjusted replacement profile provided an effective modelling approach, particularly in the case of HV and 33kV overhead line assets.

For these lines, in contrast to the single replacement unit cost required for the age-based replacement expenditure projection, the ‘adjusted’ refurbishment / replacement based model requires a blended unit cost based on an weighted average industry view taking account of the proportions of activity associated with refurbishment and replacement.

F.1.1.3 Assumptions

In order to complete our modelling of asset replacement we have found it necessary to make a number of assumptions. These are outlined below:

F.1.1.3.1 Overhead lines

LV mains and services. We compared the volumes forecast by the model for the five years of DPCR4 with those in the DNO submission and found that there was little difference between the two forecasts. Accordingly our modelling has used the industry weighted replacement profiles and our unit costs.

HV and 33kV overhead lines. The replacement/refurbishment of these lines has been modelled using ‘adjusted’ weighted industry average replacement profiles, obtained by “back-fitting” the replacement profile in order to match the volumes forecast by the model for the five years of DPCR4 with those in the DNO submission. The back-fitting resulted in adjustments to the mean asset lives, some increasing and others decreasing. The volumes derived from these profiles have been applied to a blended unit cost based on industry refurbishment and replacement activity.

For all assets with a rated voltage of 66 kV and greater (i.e. age-based asset replacement expenditure calculation) the mean life has been assumed to be 70 years. In PB Power's view the industry weighted average calculated for these asset types was considered too low.

The 12-year mean expected asset life declared in the FBPQ submission of one DNO for a number of asset types was considered to be a misinterpretation of the FPBQ as the 12 year life reflects the cyclic refurbishment period and not the mean asset life. That particular DNO's data has therefore been excluded from the industry weighted average replacement profile calculation. The asset types affected include LV mains and services, 6.6 & 11 kV bare and covered conductor, and 33 kV single and double circuit conductor overhead lines.

F.1.1.3.2 Underground cables

In general, the approach taken by the industry with regard to cable replacement is based largely on a reactive policy of undertaking fault repairs and of replacing lengths of cable only when such cable exhibits poor condition. In order to avoid possible over-forecasting of cable replacement volumes and to reflect the non-fault replacement volumes forecast by the DNOs, we have therefore adjusted the industry weighted average replacement profile of each main cable type before proceeding with age-based modelling. In general the resulting average asset lives have been increased. At LV, Consac cable has been modelled separately from the other LV cable types (PILC and Waveform have been combined) with the Consac replacement profile based on a much shorter average asset life than other types. One particular DNO's data on expected useful asset lives of LV, HV and 33kV cables was found to be inconsistent with that of other DNOs and has been excluded from the calculation of the industry average weighted replacement profiles.

F.1.1.3.3 Submarine cable

A 50-year mean life has been assumed for all asset types. One DNO has declared a 15 year mean life. As the DNO concerned has a relatively high forecast of submarine cable replacement its data would have had a significant impact on the industry weighted average asset life. Furthermore, 15 years is not in PB Power's view considered representative of the mean expected life of this asset type.

F.1.1.3.4 Benchmarking of DNO forecasts

Benchmarking of individual DNO submissions against corresponding outputs of the asset replacement model has been undertaken. This process has enabled the forecasts of individual companies to be compared thereby providing greater transparency with regard to asset class activity and highlighting any activity that may be atypical compared with industry norm performance levels. In the benchmarking process assets have been grouped under overhead lines and services, underground cables and services and substations (transformers, switchgear and substation other) enabling the forecast expenditure for each group to be benchmarked against corresponding model output. The output for each DNO by the asset classes of lines and services, cables and services and substations has been benchmarked against a median industry performer.

The approach to benchmarking has considered the DNO submission for asset replacement to include all asset replacement irrespective of the primary classification of causation such as: health and safety, environment or non-fault replacement. Expenditure associated with ESQCR has not been considered in this assessment and instead is expected to be the subject of a separate consideration by Ofgem. Combining the various asset replacement drivers into a single element overcomes differences in allocations between individual DNOs and hence avoids unduly penalising a particular company for internal allocation issues.

Certain asset classes have been combined for each DNO prior to any benchmarking assessment. This has been undertaken where the opportunity for imprecise asset replacement definition, common elements within unit cost and or related work may exist. For instance, certain expenditure items submitted as part of the DNO submission are referenced to substations with no clear attribution to either switchgear or transformer replacement. In order to avoid the risk of unjustified scaling back of companies through lack of a clear definition a generic class of substations has been created. This particular example is defined as all expenditure allocated to switchgear, transformer and other, including protection and civil works. Similarly, overhead line replacement has been combined with overhead service replacement given the likelihood that both activities will be undertaken within the same programme of work.

Certain adjustments to individual DNO submissions to compensate for pension deficit funding, lane rentals, inter-company margin and capitalised overheads have been made by Ofgem and these adjustments are taken into account. In order to determine a disaggregated forecast of capital expenditure that reconciles back to an Ofgem ‘adjusted’ submission it has been necessary to calculate a ratio between the company’s initial submission and the ‘adjusted’ submission. That ratio has been applied equally to each main asset class. These adjusted and combined generic-asset-classes form the basis from which a comparison to an equivalent asset replacement model output is drawn.

The model output is based on DNO data with regard to asset age profiles and replacement profiles from which industry average weighted replacement profiles have been derived. In that regard, the output from the model is industry-driven in terms of its input parameters. The only information that has been derived directly by PB Power has been asset replacement unit costs. A comparison of MEAVs for all 14 DNOs calculated using (new build) DNO unit costs and PB Power unit costs showed that these MEAVs were within 2 per cent of each other. A disaggregation of corresponding MEAVs by DNO in percentage terms by main asset groups and voltage levels is presented in Appendix G.

In the benchmarking process a comparison is made between the adjusted DNO submission and the corresponding model output for each of the three main asset groups:

- lines and services
- cables and services and
- substations

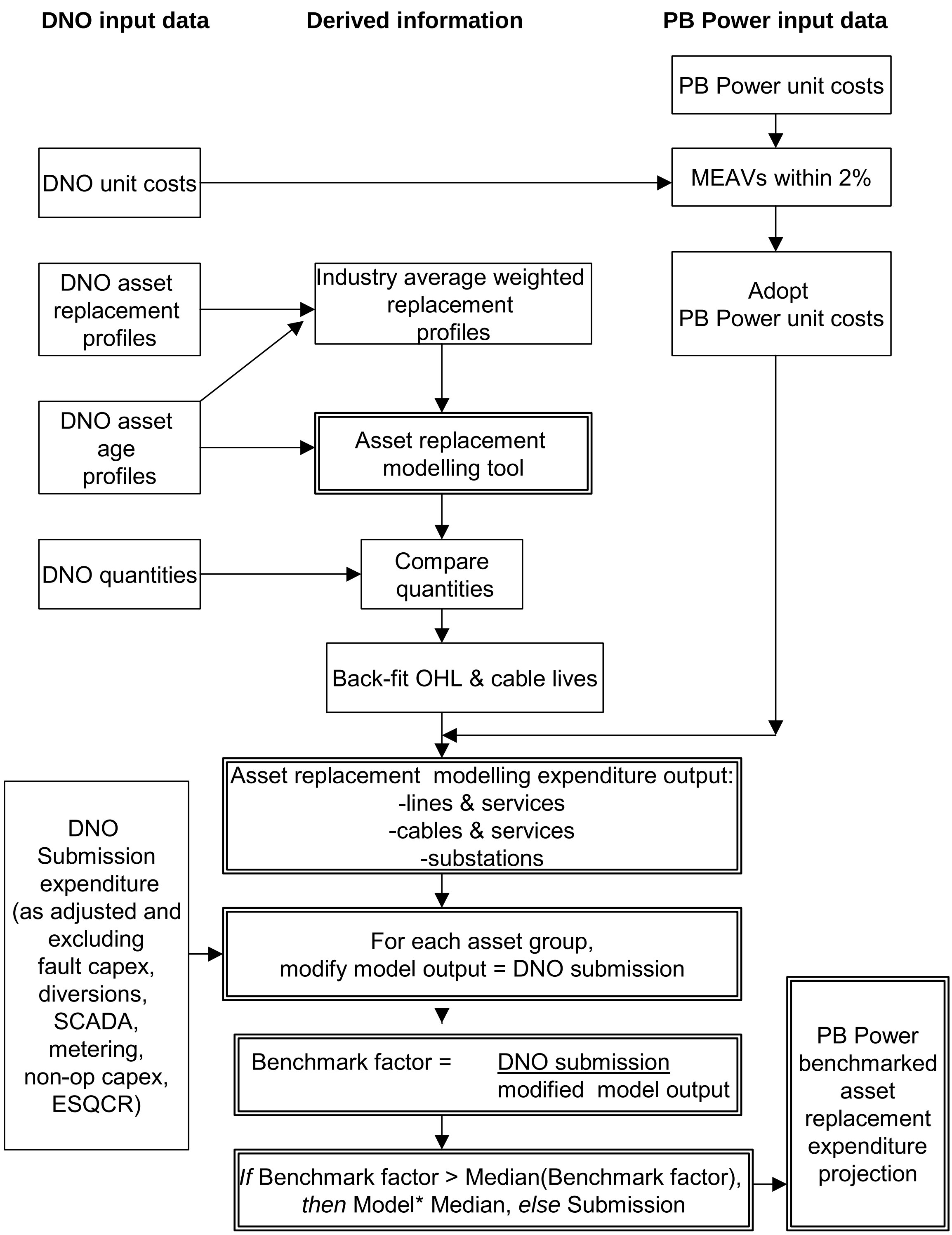
The model output is initially modified so that for each of the asset groups the overall industry (14 DNOs') expenditure predicted by the model is the same as that forecast by the DNOs. (The differences had in any case been small.) For each asset group, benchmark factors of DNO submission/model output are calculated and medians (about unity) obtained. Where the benchmark factor exceeds the median (submission exceeds model output), the resulting benchmarked output is the model output multiplied by the median. Otherwise the benchmarked output is the submission itself. Minor miscellaneous amounts not specifically included within asset groups in the FBPQ submission have been treated as pass-through with minor adjustments.

PB POWER INDUSTRY AVERAGE WEIGHTED REPLACEMENT PROFILES	MEAN LIFE (years)	STANDARD DEVIATION (years)
Overhead lines		
LV lines		
- LV mains Bare conductor	52	13
- LV mains Covered conductor	55	11
- LV services Bare conductor	51	12
- LV services Covered conductor	51	8
HV lines		
- 6.6 & 11 kV Bare conductor	45	11
- 6.6 & 11 kV Covered conductor	33	11
- 20kV Single circuit	51	11
EHV Lines		
- 33kV Single Circuit length	46	11
- 33kV Double Circuit length	69	8
- 66kV Single Circuit length - Towers	46	8
- 66kV Single Circuit length - Poles	55	8
- 66kV Double Circuit length	13	8
132kV		
- 132kV Single Circuit length	66	9
- 132kV Double Circuit length	67	12
Underground cables		
LV cables		
- LV mains (Consac)	54	14
- LV mains (PILC)	103	13
- LV mains (Plastic Waveform)	103	13
- LV services (PILC)	100	10
- LV services (Plastic Concentric)	100	10
HV cables		
- 6.6 & 11kV	85	12
- 20kV	103	16
EHV cables		
- 33kV	76	10
- 66kV	77	11
- 132kV	61	9

PB POWER INDUSTRY AVERAGE WEIGHTED REPLACEMENT PROFILES	MEAN LIFE (years)	STANDARD DEVIATION (years)
Submarine cables		
HV cables		
- 6.6 & 11kV	50	5
EHV cables		
- 33kV	50	5
- 132kV	50	6
Switchgear		
LV network		
- LV pillar	56	11
- LV Link box	90	12
HV network		
- 6.6 & 11kV switches (excluding RMU & CB)	47	8
- 6.6 & 11kV RMU	46	8
- 6.6 & 11kV CB	52	7
- 6.6 & 11kV A/RC & Sect, urban automation	42	8
EHV network		
- 33kV CB (I/D)	53	7
- 33kV CB (O/D)	52	10
- 33kV Isol (I/D)	59	8
- 33kV Isol (O/D)	53	10
- 66kV CB (GIS) (I/D)	53	10
- 66kV CB (GIS) (O/D)	50	6
- 66kV CB - other (I/D)	52	9
- 66kV CB - other (O/D)	49	7
- 66kV Isol (I/D)	55	12
- 66kV Isol (O/D)	58	10
- 132kV CB (GIS) (I/D)	56	6
- 132kV CB (GIS) (O/D)	50	8
- 132kV CB - other (I/D)	48	9
- 132kV CB - other (O/D)	49	10
- 132kV Isol (I/D)	50	7
- 132kV Isol (O/D)	48	9

PB POWER INDUSTRY AVERAGE WEIGHTED REPLACEMENT PROFILES	MEAN LIFE (years)	STANDARD DEVIATION (years)
Transformers		
HV network		
- 6.6kV PMT	55	15
- 6.6kV GMT	54	14
- 11kV PMT	56	10
- 11kV GMT	58	11
- 20kV PMT	60	9
- 20kV GMT	50	10
EHV network		
- 33kV PMT	55	12
- 33kV GMT	60	10
- 66kV	53	9
- 132kV	55	11

ASSET REPLACEMENT BENCHMARKING FLOWCHART



APPENDIX G

UNIT COSTS AND MODERN EQUIVALENT ASSET VALUE

APPENDIX G – UNIT COSTS AND MODERN EQUIVALENT ASSET VALUE

PB POWER – SCHEDULE OF UNIT COSTS

PB POWER – SCHEDULE OF UNIT COSTS		LRE	NLRE
NB. Unit costs of OHL circuit lengths include costs of supports (poles/towers), except for 66kV and 132kV replacement/refurbishment costs which exclude supports.	Unit	(new build)	(replacement/ refurbishment)
(2002/03 price levels)		(£ 000s)	(£ 000s)
Overhead lines			
LV lines			
- LV mains Bare conductor	km	25.5	25.5
- LV mains Covered conductor	km	27.5	27.5
- LV services Bare conductor	km	20.7	20.7
- LV services Covered conductor	km	23.6	23.6
HV lines			
- 6.6 & 11 kV Bare conductor	km	33.1	20.0
- 6.6 & 11 kV Covered conductor	km	43.2	26.0
- 20kV Single circuit	km	34.9	34.9
EHV Lines			
- 33kV Single Circuit length	km	38.2	38.2
- 33kV Double Circuit length	route km	60.0	60.0
- 66kV Single Circuit length - Towers	km	130.4	71.7
- 66kV Single Circuit length - Poles	km	85.1	46.8
- 66kV Double Circuit length	km	204.9	112.7
132kV			
- 132kV Single Circuit length	route km	168.4	92.6
- 132kV Double Circuit length	route km	332.8	183.1

PB POWER – SCHEDULE OF UNIT COSTS		LRE	NLRE
Underground cables			
LV cables			
- LV mains (Consac)	km	58.8	58.8
- LV mains (PILC)	km	58.8	58.8
- LV mains (Plastic Waveform)	km	58.8	58.8
- LV services (PILC)	km	35.6	35.6
- LV services (Plastic Concentric)	km	35.6	35.6
HV cables			
- 6.6 & 11kV	km	88.7	88.7
- 20kV	km	127.6	127.6
EHV cables			
- 33kV	km	195.8	195.8
- 66kV	km	826.9	826.9
- 132kV	km	1,012.5	1012.5

PB POWER - DATABASE OF UNIT COSTS (continued)		**LRE**	**NLRE**
(2002/03 price levels)	**Unit**	(new build) (£ 000s)	(replacement/ refurbishment) (£ 000s)
Submarine cables (km)			
HV cables			
- 6.6 & 11kV	km	105.8	105.8
EHV cables			
- 33kV	km	496.1	496.1
- 132kV	km	1,277.6	1277.6
Switchgear (units)			
LV network			
- LV pillar	each	4.3	4.3
- LV Link box	each	1.1	1.1
HV network			
- 6.6 & 11kV switches (excluding RMU & CB)	each	7.3	7.3
- 6.6 & 11kV RMU	each	11.3	11.3
- 6.6 & 11kV CB	each	27.8	27.8
- 6.6 & 11kV A/RC & Sect, urban automation	each	11.0	11.0
EHV network			
- 33kV CB (I/D)	each	76.8	76.8
- 33kV CB (O/D)	each	54.0	54.0
- 33kV Isol (I/D)	each	7.6	7.6
- 33kV Isol (O/D)	each	7.6	7.6
- 66kV CB (GIS) (I/D)	each	311.7	311.7

PB POWER - DATABASE OF UNIT COSTS (continued)		**LRE**	**NLRE**
- 66kV CB (GIS) (O/D)	each	311.7	311.7
- 66kV CB - other (I/D)	each	311.7	311.7
- 66kV CB - other (O/D)	each	311.7	311.7
- 66kV Isol (I/D)	each	8.0	8.0
- 66kV Isol (O/D)	each	8.0	8.0
- 132kV CB (GIS) (I/D)	each	1,012.5	1012.5
- 132kV CB (GIS) (O/D)	each	519.6	519.6
- 132kV CB - other (I/D)	each	519.6	519.6
- 132kV CB - other (O/D)	each	519.6	519.6
- 132kV Isol (I/D)	each	13.5	13.5
- 132kV Isol (O/D)	each	13.5	13.5

PB POWER - DATABASE OF UNIT COSTS (continued)		**LRE**	**NLRE**
(2002/03 price levels)	**Unit**	(new build) (£ 000s)	(replacement/ refurbishment) (£ 000s)
Transformers (units) - including tap changes and reactors			
HV network			
- 6.6kV PMT	each	3.0	3.0
- 6.6kV GMT	each	10.5	10.5
- 11kV PMT	each	3.0	3.0
- 11kV GMT	each	10.5	10.5
- 20kV PMT	each	3.7	3.7
- 20kV GMT	each	15.7	15.7
EHV network			
- 33kV PMT	each	4.3	4.3
- 33kV GMT	each	317.5	317.5
- 66kV	each	337.8	337.8
- 132kV	each	929.8	929.8

Modern equivalent asset value (MEAV)

On the following page a disaggregation of the MEAVs of the DNOs is presented, from asset quantities declared by the DNOs and from PB Power's unit costs. The total MEAV of all the 14 DNOs is calculated at some £86.6 billion.

MEA SUMMARY		Calculated using PB Power's Unit Costs					
		Trans-formers	**Switchgear**	**Overhead Line**	**Under-ground Cable**	**Services**	**Total**
1	**EHV**	52%	34%	32%	17%	0%	23%
	HV	48%	52%	53%	36%	0%	35%
	LV	0%	14%	14%	47%	100%	42%
	Total	11%	10%	23%	34%	22%	100%
2	**EHV**	63%	51%	39%	28%	0%	34%
	HV	37%	45%	45%	26%	0%	31%
	LV	0%	4%	16%	46%	100%	34%
	Total	11%	14%	19%	45%	10%	100%
3	**EHV**	60%	26%	53%	14%	0%	22%
	HV	40%	60%	36%	32%	0%	29%
	LV	0%	15%	11%	54%	100%	49%
	Total	8%	10%	15%	44%	22%	100%
4	**EHV**	54%	25%	60%	20%	0%	23%
	HV	46%	57%	25%	33%	0%	28%
	LV	0%	18%	15%	47%	100%	49%
	Total	8%	10%	12%	46%	23%	100%
5	**EHV**	54%	23%	51%	17%	0%	26%
	HV	46%	64%	35%	35%	0%	34%
	LV	0%	13%	13%	48%	100%	40%
	Total	10%	9%	20%	49%	12%	100%
6	**EHV**	56%	28%	47%	14%	0%	22%
	HV	44%	62%	40%	36%	0%	33%
	LV	0%	10%	13%	50%	100%	45%
	Total	8%	13%	18%	39%	22%	100%
7	**EHV**	51%	30%	100%	29%	0%	26%
	HV	49%	51%	0%	26%	0%	26%
	LV	0%	19%	0%	44%	100%	48%
	Total	6%	9%	0%	71%	15%	100%
8	**EHV**	55%	31%	50%	24%	0%	28%
	HV	45%	66%	41%	33%	0%	33%
	LV	0%	3%	9%	44%	100%	39%
	Total	7%	12%	18%	47%	17%	100%
9	**EHV**	62%	28%	58%	17%	0%	26%
	HV	38%	68%	33%	30%	0%	32%
	LV	0%	4%	10%	53%	100%	42%
	Total	9%	13%	13%	54%	11%	100%
10	**EHV**	62%	28%	63%	27%	0%	31%
	HV	38%	70%	32%	27%	0%	31%
	LV	0%	3%	5%	46%	100%	38%
	Total	8%	14%	14%	49%	14%	100%
11	**EHV**	54%	45%	36%	14%	0%	24%
	HV	46%	43%	55%	38%	0%	35%
	LV	0%	12%	8%	49%	100%	41%
	Total	11%	12%	21%	34%	21%	100%
12	**EHV**	51%	12%	15%	16%	0%	16%
	HV	49%	73%	68%	35%	0%	40%
	LV	0%	15%	17%	50%	100%	45%
	Total	9%	13%	12%	51%	15%	100%
13	**EHV**	47%	16%	25%	22%	0%	23%
	HV	53%	68%	65%	39%	0%	48%
	LV	0%	16%	10%	39%	100%	29%
	Total	11%	10%	33%	35%	11%	100%
14	**EHV**	56%	23%	57%	25%	0%	31%
	HV	44%	64%	29%	32%	0%	33%
	LV	0%	13%	14%	43%	100%	36%
	Total	10%	14%	19%	46%	11%	100%
All 14 DNOs	**EHV**	56%	28%	46%	21%	0%	26%
	HV	44%	61%	41%	32%	0%	33%
	LV	0%	11%	12%	47%	100%	58%
	Total	9%	12%	16%	48%	16%	100%