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SEPD

DPCR4 – FBPQ ANALYSIS AND CAPEX PROJECTIONS

OCTOBER 2004

LIST OF REVISIONS

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Final	18/06/04	All	Adjustment following submission of final capital expenditure numbers.			
Final	23/10/04	All	Revision of model and allowance levels following DNO meetings with Ofgem and Ofgem September paper.			

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APPENDICES:

LIST OF ABBREVIATIONS

ACS	Average Cold Spell
Capex	Capital expenditure
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
LRE	Load-related expenditure
LV	Low voltage (i.e. less than 1kV and here 230/400V)
m	Million
MEAV	Modern Equivalent Asset Value
MPAN	Meter Point Administration Number
MPRS	Meter Point Registration System
MW	Megawatt (a unit of power)
NGC	National Grid Company
NLRE	Non-load related expenditure
NUTS	Nomenclature of Units for Territorial Statistics
OHL	Overhead line
ONS	Office of National Statistics
PB	Parsons Brinckerhoff

QoS	Quality of supply (reliability/interruption performance)
SEPD	Southern Electric Power Distribution plc
SHEPD	Scottish Hydro-Electric Power Distribution Ltd
SSAP	Standard accountancy practice
SSE	Scottish and Southern Energy plc

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 SEPD's adjusted DPCR3 projection, adjusted DPCR4 forecast (submission), PB Power's modelling results and view of proposed expenditure.

Expenditure Category (£m)	**Adjusted DPCR3 Projection (£m)**	**Adjusted DPCR4 Forecast (£m)**	**Model Output (£m)**	**PB Power Opinion (£m)**	**PB Power Comments**
Load Related Expenditure - Gross	317	357.1	347.4	357.1	The model was run with the forecast LRE uplifted for competition in connections. The reduction indicated by the model (£ 9.5m) is due to the expenditures in DPCR2, DPCR3 and DPCR4 being marginally higher than the benchmark for these three price controls. As SEPD has however two major 132kV reinforcement schemes in its budget, supported by scheme papers, we would consider the submission to be reasonable.
Customer Contributions	(152)	(154.8)	-	(154.8)	The customer contributions figure is an estimate (by SEPD) as SEPD has not provided for new connections or customer contributions in its submission.
LRE Net	**165.0**	**202.3**	**-**	**202.3**	
Asset Replacement	208.7	308.8	302.6	302.2	Although the asset replacement model predicts higher expenditures on substations and cables than in the SEPD forecast, the benchmarked outputs nevertheless reflect the forecast.
Other	86.5	72.6		72.6	£72.6m comprises SCADA (£6.3m), meters (£25.8m) and fault replacement (£40.5m), but excludes ESQCR.
NLRE Total	**295.2**	**381.3**	**-**	**374.8**	
Non Operational	2.1	5.0	-	5.0	Not reviewed.
DNO Total	**462.3**	**588.6**	**-**	**582.1**	
DNO Total				*510.8*	*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.

The SEPD forecasts have been reduced by £16m in respect of the funding of the pension deficit and by £14m for capitalised overheads.

Load related expenditure

- SEPD's forecast load-related expenditure (£357.1m gross, £202.3m net) is higher than the DPCR3 projections (£317.0m gross, £165.0m net) and higher than the DPCR3 allowances (£247m gross, £163.2m net)
- The figure of £357.1m gross for the adjusted DPCR4 forecast was calculated by PB Power from an estimate of gross capital costs in providing connections of £154.8m, based on an estimate provided by SEPD.

Non-load related expenditure

- For DPCR4 SEPD forecasts asset replacement expenditure of £308.8m, being some £100m higher than the DPCR3 projection. The main reason for the increase is increased expenditure on replacement of substations, overhead lines and underground cables.

- The increase in expenditure on substations results from an increase in the replacement rate of transformers and switchgear. For example the annual replacement rate of 11 kV RMUs has increased from 0.9% in DPCR3 to 1.6% in DPCR4 (£7m over DPCR4) and the annual replacement rate of 11 kV GMTs has increased from 0.4% in DPCR3 to 0.8% in DPCR4 (£4.7m over DPCR4). The underlying reasons for the increase in replacement rates across all substation assets should be discussed further with SEPD[1].

- To address marginally increasing fault rates and to improve resilience SEPD plan to rebuild/reconductor some 550km of HV overhead line with BLX covered conductor (£21.5m), which has a higher unit cost than bare conductor. The SEPD proposal represents an improvement in the resilience of the network as well as asset replacement. Around £6m of the £21.5m could be therefore moved into the Quality of Supply case or the DNO case as this represents the difference between open wire construction and BLX.

[1] Where detailed cost items are cited, these are before the application of adjustments described earlier and therefore are directly identifiable from SEPD's submission.

- SEPD also plans to rebuild some 950km of LV overhead line with ABC at a cost of £24.7m, again offering a more resilient performance. The SEPD proposal represents a significant increase in ABC replacement rate in DPCR4 compared to DPCR3 (141km in total in DPCR3 to 715km in DPCR4). The underlying reasons for the increase in replacement rate should be discussed further with SEPD.

- To address increasing fault rates on EHV, HV and LV cables SEPD plans cable replacement in DPCR4 in excess of DPCR3 replacement by £17m. The underlying reasons for the increase in fault rates and replacement rates should be discussed further with SEPD.

- SEPD has extended asset lives and inspection intervals to levels more than other DNOs. As SEPD appears to be extending the envelope of asset lives there may be an issue of stewardship in the long term, we suggest that consideration be given to reviewing the reporting and audit of the condition of assets following the ARM survey report.

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[2], which is not separately identified in the DPCR3 projections and is not included in the Base Case DPCR4 forecast.

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

Quality of supply scenarios

- SEPD has identified seven improvement measures, (BLX rebuilds, undergrounding 11kV lines, feeder splitting, rural automation, LV consac overlay and underground distribution boxes) to produce the 2009/2010 quality of supply improvements. The SEPD proposals would incur a cost of £141.4m.

- The QoS and sensitivities and accelerated line upgrade analysis has been undertaken at a detailed level using the standard SEPD risk analysis and decision making tools and therefore the results and expenditure may be expected to have a high degree of dependability.

- The resilience and amenity undergrounding analysis has been undertaken at a high level.

DNO alternative case

- The total additional cost of the SEPD alternative scenario over the Base Case is £54m, an increase of 9 per cent and £653.5m in total, and is related principally to the network resilience and performance areas. Modest improvements in reliability performance are claimed.

PB POWER VIEW ON LOAD RELATED AND NON LOAD RELATED ALLOWANCES

Load related expenditure

- In our modelling we made reductions to forecast customer numbers and units distributed, both of which were considered to be high.
- The model indicates a gross load-related expenditure level of £347.5m, being a reduction of £9.7m on the DNO submission. This reduction reflects the expenditures in DPCR2, DPCR3 and DPCR4 being marginally higher than the benchmark for these three price controls. As SEPD has however two major 132kV reinforcement schemes in its budget, supported by scheme papers, we would consider the submission to be reasonable.

Non-load related expenditure

- Although the asset replacement model predicts higher expenditures on substations and cables than in the SEPD forecast, the benchmarked outputs nevertheless reflect the forecast.
- In PB Power's opinion the allowed asset replacement expenditure should be £302.2m. With the inclusion of SCADA, meters and fault replacement, the corresponding overall non-load related expenditure would be £374.8m. ESQCR related expenditure is excluded as this matter is being considered separately by Ofgem.

Quality of supply scenarios

- We would consider the headline cost of about £260 per annual customer hour saved for the central scenario as being on the high side, but not necessarily untypical.
- The response to the resilience undergrounding scenario however raises the question as to how resilience improvements, particularly to occasional severe weather, should be evaluated.

Conclusion

Subject to the above observations, the above considerations would reduce the SEPD submission by £6.5m and would generate an allowance of £582.1m.

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.

Ofgem published the Forecast Business Plan Questionnaire (FBPQ) in October 2003, prior to appointing PB Power. 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% on customer interruptions and ± 5% on customer minutes lost 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 was 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 non-load related expenditure, a comparison of the DNO forecast with the output of a PB Power model using industry average weighted asset replacement profiles and PB Power's unit costs.

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

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.

2 DNO SUBMISSIONS

2.1 Base case

2.1.1 General

SEPD's approach to forecasting the Capex projections in the Base Case has been to:

- include non load related expenditure to offset network deterioration and keep quality of supply broadly constant
- include load related expenditure to provide for:
    - Compliance with Licence Condition ER P2/5 – Security of Supply.
    - Overloaded circuits, plant and equipment.
    - Reinforcement due to fault level limitations.
    - New Business – 25% rule.
    - Voltage outside statutory limits.

The SEPD philosophy with regard to forecasting load and non-load expenditure is covered in the following SEPD policy documents.

- Underground cable replacement
- Rising mains refurbishment
- Load related reinforcement (Major Projects at Primary level and above)
- Non Load related reinforcement (Major Projects at Primary level and above)
- HV Ground mounted substation refurbishment
- EHV/HV Overhead Line refurbishment strategy
- Embedded Diesel Generating Plant

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	**247.0**	**317.0**	**364.5**	**8.0**	**372.5**
Non Load Related	**403.5**	**295.2**	**387.9**	**8.0**	**395.9**
Gross Capex less Non Op Capex	***650.5***	**612.2**	***752.4***	***16.0***	***768.4***
Non Op Capex (Not Assessed)	16.8	2.1	5.0	0.0	5.0
Total Gross Capex	**667.3**	**614.2**	**757.4**	**16.0**	**773.4**
Contributions	-83.8	-152.0	-158.0	-3.5	-161.5
Net Load Related	**163.2**	**165.0**	**206.5**	**4.5**	**211.0**
Total Net Capex	**583.5**	**462.3**	**599.4**	**12.5**	**611.9**
Non Load Related Summary					
Replacement	348.7		300.0	6.6	306.6
ESQCR			6.7	0.1	6.8
Heath & Safety			0.0	0.0	0.0
Environment			8.5	0.2	8.7
Sub Total - Model Comparison	**348.7**	**208.7**	**315.2**	**6.9**	**322.1**
Diversions	24.6	0.0	0.0	0.0	0.0
SCADA		1.3	6.5	0.1	6.6
Sub Total	***373.3***	***210.0***	***321.6***	***7.1***	***328.7***
Metering (Not Assessed)	30.2	47.7	25.8	0.0	25.8
Sub Total	***403.5***	**257.7**	***347.4***	***7.1***	***354.5***
Fault Capex (Not Assessed)		37.5	40.5	0.09	41.4
Non Load Related Total	**403.5**	**295.2**	**387.9**	**8.0**	**395.9**

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	-8.0	-7.4	0.0	0.0	**357.1**
Non Load Related		-8.0	-6.6	0.0	0.0	**381.3**
Gross Capex less Non Op Capex	***0.0***	***-16.0***	***-14.0***	***0.0***	***0.0***	**738.4**
Non Op Capex (Not Assessed)						**5.0**
Total Gross Capex	**0.0**	**-16.0**	**-14.0**	**0.0**	**0.0**	**743.4**
Contributions	0.0	3.5	3.2	0.0	0.0	-154.8
Net Load Related	**0.0**	**-4.5**	**-4.2**	**0.0**	**0.0**	**202.3**
Total Net Capex	**0.0**	**-12.5**	**-10.8**	**0.0**	**0.0**	**588.6**
Non Load Related Summary						
Replacement		-6.6	-6.1	0.0	0.0	293.9
ESQCR		-0.1	-0.1	0.0	0.0	6.6
Heath & Safety		0.0	0.0	0.0	0.0	-
Environment		-0.2	-0.2	0.0	0.0	8.3
Sub Total - Model Comparison		**-6.9**	**-6.4**	**0.0**	**0.0**	**308.8**
Diversions		0.0	0.0	0.0	0.0	-
SCADA		-0.1	-0.1	0.0	0.0	6.3
Sub Total		***-7.0***	***-6.6***	***0.0***	***0.0***	***315.1***
Metering (Not Assessed)		-0.0	-0.0	0.0	0.0	25.8
Sub Total		***-7.0***	***-6.6***	***0.0***	***0.0***	***340.9***
Fault Capex (Not Assessed)		-0.9	-0.0	0.0	0.0	40.5
Non Load Related Total		**-7.9**	**-6.6**	**0.0**	**0.0**	**381.3**
Total Adjustments	**0.0**	**-16.0**	**-14.0**	**0.0**	**0.0**	**-30.0**

2.1.2 Load related capex

2.1.2.1 Network reinforcement

To produce future demand forecasts SEPD uses 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 average cold spell corrected maximum demand. The forecast obtained is compared with the forecast from the previous year to identify any step changes in demand. Any such step changes are rationalised to produce a credible future forecast.

To derive a forecast at the 132/33 kV substation level SEPD aggregates the maximum demand of all primary substations associated with a bulk supply point (BSP). The aggregated maximum demand of the current year is also compared with the actual maximum demand obtained via SCADA at the BSP. The ratio of actual maximum demand to aggregated maximum demand provides a diversity factor that is used to convert aggregated maximum demand to simultaneous maximum demand (SMD). The SMD is used to determine compliance with ER P2/5 – Security of supply.

SEPD has identified two major 132kV reinforcement schemes planned to be undertaken during DPCR4, namely reinforcement of the:

- Fleet – Basingstoke – Reading 132kV system at an estimated cost of about £20.1m in DPCR4 and
- Mannington – Poole – Shaftesbury – Salisbury 132kV system at an estimated cost of about £13.5m.

In the SEPD area there are some 80 bulk supply substations. SEPD states that, according to the demand forecast carried out in 2002/03, at 15 of these substations the security of supply criterion for group demand would be non compliant under first and/or second circuit outages for the period 2005/06 to 2009/10. Furthermore there are over 500 primary substations and the 2002/03 demand forecast shows that during DPCR4 some 40 substations will exceed their firm capacity and will require reinforcement. Details of these are provided in Section 0 of Appendix A.

As the demand on plant and equipment normally increases each year SEPD undertakes a high-level system analysis to identify overloaded plant, equipment and circuits. Based on the 2002/03 demand forecast and power system analysis under N-1 and N-2 (as appropriate) SEPD estimates that, in addition to the 132kV systems, BSPs and primary substations already mentioned, some twenty eight 33 kV circuits and two 33/11 kV transformers will become overloaded during DPCR4. Details of these are provided in Section 0 of Appendix A.

SEPD has also identified three 33kV sites and thirteen 11kV sites where switchgear will require replacement due to fault levels.

2.1.2.2 New connections forecast expenditure

At the start of DPCR3 SEPD changed the set up of its new connection business to a 'ring fenced' business within SEPD. The business is incentivised to increase profit through efficiency gains and hence minimise the amount of capital required from the 'wires' business. The connections business has been combined into one managed unit within the SSE Group (Scottish Hydro-Electric and Southern Electric). The result of this is that SEPD have not included new connections or customer contributions in their submission. (SSE did subsequently provide figures for the gross capital costs and connection contributions in providing connections for 2002/03).

2.1.2.3 Comments and issues associated with the load related expenditure forecast

The SEPD load related capex submission (£ 202.3m – (after adjustments)) is higher than the actual and forecast level for DPCR3 (£165.0m). These expenditures are net of customer contributions due to the change in policy for charging new business. SEPD plans to apply full costs to new business connections during DPCR4 and have therefore not included any allowances in its forecasts other than those for final connections and a sum to cover allowances for schemes quoted pre 2005 but which continue into DPCR4.

We consider the basis of the load related expenditure forecast to be sound as it relies on well established demand forecasting techniques and power system studies that identify detailed site-specific reinforcement requirements.

2.1.3 Non-load related capex

The main drivers for non-load related capital expenditure in SEPD are:

- Asset Condition
- Network Security
- Fault Performance
- Spares and Obsolescence
- Safety
- Age

SEPD prepares a five-year non-load related capital expenditure plan that is primarily based on asset age and comparison with assigned useful asset life. Other information such as external and internal condition and known design problems is used to priorities the five-year plan. A yearly non-load related budget is created using the information in the five-year plan and actual asset condition information from the field. The SEPD decision making process, which is based on a scoring method that takes in to account the five main drivers listed above, includes whether to replace, refurbish or carry out additional maintenance.

A comparison of asset lives shows that SEPD's asset lives for plant and equipment are among the longest in the UK. Examination of asset ages shows that SEPD's assets are generally around the average age across the industry. The increase in expenditure proposed by SEPD for DPCR4 over DPCR3 is driven substantially by the age profiles of plant and equipment. Furthermore SEPD's policy is to replace HV bare conductor overhead lines with BLX covered construction that is stated to be more resilient.

The three major areas of non-fault replacement in SEPD are substations, overhead lines and underground cables; these areas are further discussed below.

2.1.3.1 Substation non-fault replacement

The classification of substations includes mainly switchgear and transformers. Details of the proposed replacement levels for transformers and switchgear are provided in Section 0 of Appendix A. The replacement rates proposed by SEPD of 9.5% for transformers and 6% for switchgear are consistent with the SEPD risk assessment replacement process and are indicative of very long asset lives. The total non-fault capex proposed for substations is £113m. We would consider these replacement proposals to be reasonable.

2.1.3.2 Overhead lines non-fault replacement

The SEPD proposals for overhead line investment are based on the refurbishment cycle of 12 years for all overhead lines as indicated above plus short-term actions to ensure that the risk of incident or loss of supply is managed to within acceptable levels during DPCR4. The capex proposals are based on a consideration of the following areas:

- Storm resilience
- New requirements driven by changes to the ESQC Regulations
- High Risk Sites
- "Rutter Pole" circuits
- LV Lines

In order to counter marginally deteriorating fault rates and to improve resilience, SEPD plans to rebuild/reconductor some 550km of HV overhead line with insulated BLX conductor (£21.5m) and some 950km of LV line with ABC (£24.7m), under the Base Case.

SEPD consider that the introduction of the Electricity Safety, Quality and Continuity Regulations 2002 (ESQCR) has introduced a number of new duties for DNOs. In particular, the new regulations have driven the need for additional investment to address two new requirements:

- Existing bare LV conductors within 3m of habitation will require to be replaced with insulated conductor or ABC. SEPD estimates expenditure of £1.04m per annum (£5.2m in total for DPCR4) corresponding to 200km of LV line, based on a 10 per cent sample
- All overhead lines and substations require risk assessment and the results catalogued on a new database. SEPD estimate that over DPCR4 the risk assessment and database establishment will cost £1.5m. In addition an annual expenditure of £750k per annum will be required to address the risks identified by the risk assessment, particularly at leisure sites including playfields, camping areas and fishing areas.

SEPD has budgeted £6.6m of non-load related capex to meet the requirements of ESQCR, comprising £5.2m for replacing 200km of LV bare conductor line and £1.5m for high risk site assessments. (SEPD Company Case item 6) refers).

Other measures include light refurbishment at all voltage levels as well as some major EHV refurbishment. Overall non-load related expenditure on overhead lines, including fault expenditure, averages £19.9m per year.

2.1.3.3 Underground cables non-fault replacement

SEPD indicates that expenditure on underground cables is forecast to increase from DPCR3 levels to a level of about £17m per year, excluding faults, in DPCR4. This increase reflects deteriorating fault rates that will be addressed on an ad hoc basis. The SEPD proposals for underground cable replacement include the following:

- Replacement of Iver to Hillingdon 66kV cables which are part gas filled and part solid construction and have a history of failures
- Replacement of 33kV HSL cables in the Southampton area; the cables concerned are of small cross section, have lower fault ratings and there is evidence of drying of papers resulting in discharge
- 11kV cables where these have a high fault rate
- LV consac cable where there are continued problems with resin joints, involving an annual expenditure of £11m covering the application of both “fast-track” and overlay methods.

SEPD has also identified some 132kV gas compression cables and one of the 132kV 3-core fluid filled submarine cables under the Solent as candidates for replacement in the next ten years. In addition the company has also made provision to prevent and contain leaks on fluid filled cables. We would comment that as cables at this voltage are expensive items, expenditure can exhibit volatility.

We consider the basis of the non-load related expenditure forecast to be sound as it relies on well-documented policies and structured risk, RCM and condition processes that identify asset specific replacement requirements.

2.1.4 Comments and issues associated with the non-load related expenditure forecast

i. SEPD proposes asset replacement expenditure (excluding metering, fault repairs and after adjustments) of £308.8m, being some £ 100m higher than for DPCR3. (Difficulties over normalisation of costs prevent a more detailed comparison.) The principal reasons for the increase is however increased expenditure on replacement of substations, overhead lines and underground cables.

ii. SEPD has extended asset lives and inspection intervals to levels beyond any of the other DNOs. (The company states that its condition monitoring approach has meant that the average life of ground-mounted equipment has moved from 40 to 55 years.) As SEPD appears to be extending the envelope of asset lives there may be an issue of stewardship in the long term, we suggest that consideration be given to review the reporting and audit of condition of assets following the ARM survey report.

iii. SEPD plans to rebuild/reconductor some 550km of HV overhead line with BLX covered conductor (£21.5m) which has a higher unit cost than bare conductor but which the company states offers a more resilient performance.

iv. SEPD also plans to rebuild some 950km of LV overhead line with ABC at a cost of £24.7m, again offering a more resilient performance.

v. SEPD's proposals to meet the ESQCR requirements are estimated to cost a total of £6.6m over DPCR4 and have been included in the Base Case. £5.2m of this expenditure is concerned with replacing some 200km of LV line with ABC where bare conductor lines have inadequate clearances. £1.5m of this total is associated with the establishment of the risk assessment database and undertaking the risk assessments and represents 50% of the total for SSE. £

vi. We consider the basis of the non-load related expenditure forecast to be sound as it relies on well-documented policies and structured risk, RCM and condition processes that identify asset specific replacement requirements.

2.2 Quality of supply/sensitivity scenarios

2.2.1 Network performance improvements

Table 2.2 below sets out the proposed network performance targets for 2010 and 2020.

Table 2.2 - Proposed Network Performance Targets

02/03 actual		01/02 & 02/03 ave		2010 Scenario		2020 Scenario		(ave/2010)%	
CI	CML	CI	CML	CI	CML	CI	CML	CI	CML
87.9	73.4	92.4	82.7	84.4	74.0	72.5	60.9	109%	112%

Note: The above CIs and CMLs are unplanned CIs and CMLs.

SEPD's quality of supply submission is described more fully in Appendix B.

2.2.1.1 Quality of supply – improvement scenario

SEPD has identified seven improvement measures, (BLX rebuilds, undergrounding 11kV lines, feeder splitting, rural automation, LV consac overlay and underground distribution boxes) to produce the 2009/2010 quality of supply improvements. The SEPD proposals would incur a cost of £141.4m and would produce improvements of 6.34 CIs and 10.98CMLs. We would consider the headline cost of about £260 per annual customer hour saved as being on the high side, but not necessarily untypical.

2.2.1.2 Quality of supply – sensitivities

In responding to the quality of supply sensitivities, SEPD has combinations of the measures proposed for the central quality scenario as modules. Further details are summarised in Appendix B.

SEPD's proposal to meet sensitivity 3 (CI performance reduced 2 per cent relative to the central quality scenario) shows a CI gain of less than the 2 per cent reduction, at an estimated cost of £32.9m additional to the central quality scenario.

To meet sensitivity 5 (CML performance reduced 5 per cent relative to central quality scenario), SEPD estimates expenditure of £135.86m additional to the central quality scenario.

To meet sensitivity 2 (CI performance increased 2 per cent relative to the central quality scenario), SEPD estimates expenditure of £35.2m additional to the Base Case.

To meet sensitivity 4 (CI performance increased 2 per cent relative to the central quality scenario), SEPD estimates expenditure of £58.4m additional to the Base Case.

2.2.1.3 Accelerated line upgrade

SEPD believes that its existing HV lines are essentially to EATS 43-40 standard. 30 per cent of these lines are of BLX covered conductor construction. For the purposes of this scenario, SEPD proposes to rebuild an additional 20 per cent of its lines with BLX. This represents an additional 2080km over and above the Base Case Scenario costing £81m and providing an estimated 2.08CI and 3.29CML benefit.

2.2.1.4 Undergrounding existing overhead lines (network resilience)

In order to underground 2% of its HV overhead network SEPD would need to address around 268km of lines at a cost of approximately £17.61m. As well as giving resilience benefits SEPD estimates that this scenario would improve network performance by about 0.84 CML and 0.3 CI. This response however raises the question as to how resilience improvements, particularly to occasional severe weather, should be evaluated.

2.2.1.5 Undergrounding existing overhead lines (amenity value)

To underground all overhead lines within National Parks and Areas of Outstanding Natural Beauty SEPD estimates a cost £359.9m to underground some 2766km of lines at all voltage levels.

2.2.1.6 Comments and issues associated with the quality of supply scenarios

i. SEPD considers that the proposals set out under its DNO alternative Scenario offer represents a measured and sensible approach to network investment, builds on the submitted Base Case and reflects a worthwhile improvement to customer service.

ii. The QoS and sensitivities and accelerated line upgrade analysis has been undertaken at a detailed level using the standard SEPD risk analysis and decision making tools and therefore the results and expenditure may be expected to have a high degree of dependability.

iii. We draw attention to the relatively high cost to benefit of the proposed quality measures and that one of the sensitivity cases is non-compliant.

iv. The amenity undergrounding analysis has been undertaken at a high level.

2.3 DNO alternative scenario

The SEPD alternative case includes the following areas, some of which are already included in the Base Case:

- Network resilience and performance
    - an additional 550km of replacement of HV lines with BLX covered conductor construction (£21.5m) over the Base Case to improve resilience further
    - fitting of pole-mounted auto-reclosers and automatic sectionalising links to bare conductor HV circuits as well as splitting of urban and rural feeders to address the concentrations of customers at “tail ends” (£18.6m)
    - undergrounding 210km of overhead lines (£13.8m)
- switchgear replacement (£71m), transformer replacement (£48m)
- Environmental factors including oil containment (£15m)
- ESQC Regulations (£6.6m)
- Lane rentals (As requested by Ofgem SEPD has not included any costs in the business plan for lane rentals, although an annual increase of £17m (£11m on opex and £6m on capex is indicated by SEPD)
- Consac LV cable (£46m)

The total additional cost of the SEPD alternative scenario over the Base Case is £54m, an increase of 9 per cent and £653.5m in total, and is related principally to the network resilience and performance areas. A CI improvement of 3.5 and a CML improvement of 6 as well as resilience improvements are claimed.

3 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 and the following sections discuss the validation and adjustment of the input variables and the model outputs.

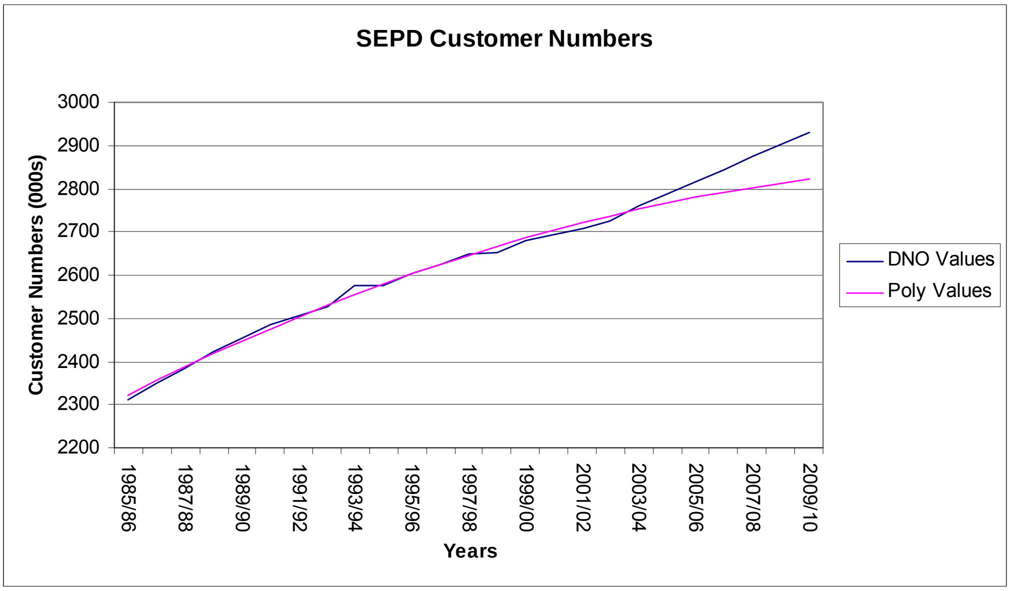
3.2 Load related expenditure

3.2.1 Model inputs

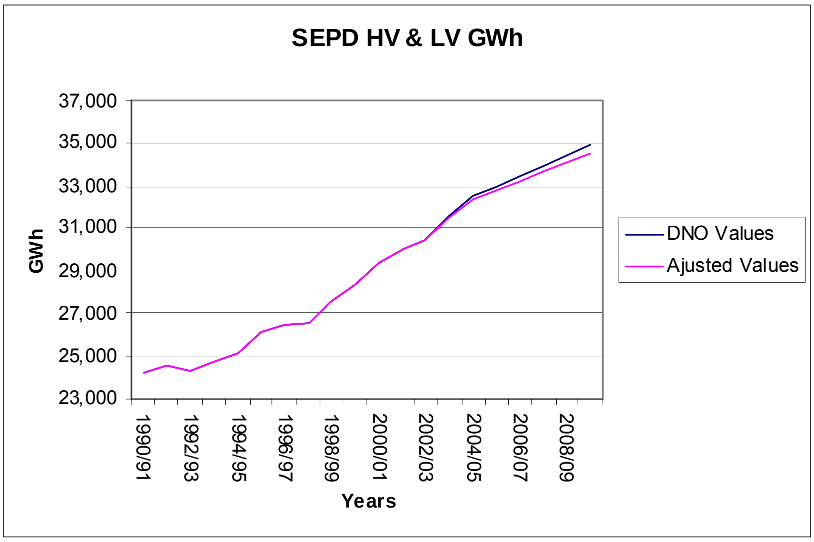
The forecast customer numbers for SEPD are significantly higher than the trend for the historic data. Therefore a 2nd order polynomial has been fitted to the historic data and then extrapolated for the forecast values. This polynomial has also been used for the historic data as it removes the small amount of noise that has occurred. The polynomial can be seen below.

$$y = 0.5148x^2 + 34.135x + 2289.6$$

Table 3.1 -Adjustment of Customer Numbers



A review of the DNO HV & LV load forecast has been carried out as part of the Load Related Expenditure modelling. As the GVA analysis indicated that the SEPD load forecast was high an adjustment has been made to reduce the DNO submitted value. This reduction takes the form of a 57 GWh year on year decrease from the submitted value. The reduction value used has been calculated as part of the GVA analysis.



3.2.2 Model outputs

The following table sets out the model output compared to DPCR 2 & 3 expenditure and DPCR4 submission. The DPCR4 submission for LRE has been increased to reinstate an estimate of the connections expenditure (Table 2.1 refers)

Table 3.2 - Load Related Capex Model Outputs

LRE DCPR2 (excluding generation)	LRE DCPR3 (excluding generation)	Submitted LRE Gross DCPR04 (excluding generation)	Model Output LRE for DCPR4
(£m)	(£m)	(£m)	(£m)
309.0	317.0	357.1	347.4

3.2.3 Load related expenditure modelling comments

The model output shows a small reduction relative to the forecast expenditure. The reduction indicated by the model (£ 9.7m) is due to the expenditures in DPCR2, DPCR3 and DPCR4 being marginally higher than the benchmark for these three price controls. As SEPD has however two major 132kV reinforcement schemes in its budget, supported by scheme papers, we would consider the submission to be reasonable.

3.3 Non-load related expenditure

3.3.1 Model inputs

No specific model input adjustments were made for SEPD.

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

3.3.2 Model outputs

Table 3.3 below provides a comparison between the DNO submission and the model outputs for the main asset classes.

Table 3.3 - Comparison of NLRE Model Outputs with DNO Submission

Submission	FBPQ Table 26	Adjusted submission	Combined	Adjusted submission	Model output	Bench-marked output	PB Power Opinion
Lines	99.0	95.1	Lines & services	96.7	101.5	96.7	
Cables	84.9	81.5	Cables & services	82.0	103.3	82.0	
Transformers	45.4	43.6	Substations	116.6	182.7	116.6	
Switchgear	63.1	60.6	Part Submission Total	295.3	387.5	295.3	
Services and Lines	2.1	2.1					
SMC	0	0					
Other Substations	12.9	12.4					
Other Not Modeled	7.6	7.6	Other Not Modeled	7.6		7.3	
Total	315.2	302.9	Total	302.9		302.6	302.2

3.3.3 Non load related expenditure modelling comments

The DNO Submission figures in the above table exclude fault expenditure.

(The corresponding expenditures for the items modelled including fault costs are: substations (£126m), overhead lines (£99.5m), underground cables (£118.9m), submarine cables (£1.5m) and service lines and cables (£2.0m), totalling £347.5m.) .

For overhead lines the model's prediction and the submission expenditures are similar.

The model's prediction of substation expenditure is higher than that in the DNO submission. In more detail the model predicts higher expenditures for both transformer replacement and switchgear (including protection, civil works and other). A comparison of asset volumes has shown that whereas the model predicts a higher replacement volume of distribution transformers, for primary transformers the reverse applies. The mean asset lives declared by the company and the "industry weighted" lives used in the model are however very similar. We would therefore conclude at this point that SEPD's replacement policy in practice differs from the asset lives stated in the FBPQ.

In respect of cables the model is predicting higher expenditure overall than the submission. In detail however the model is predicting lower volumes and expenditure for LV cables (whereas SEPD's non-fault LV cable replacement comprises some 52.7km at £11.9m per year), but higher volumes and expenditures at HV and EHV, particularly HV. We would also comment that we found SEPD's declared unit cost for replacement of an LV mains cable at £184,000/km to be inexplicably high.

Following benchmarking the model outputs are as per the submission.

In PB Power's opinion the non-load related expenditure corresponding to the model output should be £302.2m. This amount excludes ESQCR related expenditure, diversions, metering and fault capital expenditure. Furthermore ESQCR related expenditure has been excluded from the corresponding overall total as the matter of ESQCR related expenditure is being considered separately by Ofgem.

3.4 PB Power's opinion of allowances

Our findings are summarised in the table below.

Table 3.4 – PB Power's Opinion of Allowances (£m)

Item	Adjusted DPCR 3 Projection	Adjusted DPCR4 Forecast	Model Output, benchmarked	PB Power Opinion
Gross Load Related	**317.0**	**357.1**	**347.4**	**357.1**
Non Load Related	**295.2**	**381.3**		**374.8**
Gross Capex less Non Op Capex	**612.2**	**738.4**		**731.8**
Non Op Capex (Not Assessed)	2.1	**5.0**		5.0
Total Gross Capex	**614.2**	**743.4**		**736.8**
Contributions	-152.0	-154.8		-154.8
Net Load Related	**165.0**	**202.3**		**202.3**
Total Net Capex	**462.3**	**588.6**		**582.1**
Non Load Related Summary				
Replacement		293.9		
ESQCR		6.6		
Heath & Safety		-		
Environment		8.3		
Sub Total - Model Comparison	**208.7**	**308.8**	**302.6**	**302.2**
Diversions		-		0.0
SCADA	1.3	6.3		6.3
Sub Total	***210.0***	***315.1***		***308.5***
Metering (Not Assessed)	47.7	25.8		25.8
Sub Total	**257.7**	***340.9***		**334.3**
Fault Capex (Not Assessed)	37.5	40.5		40.5
Non Load Related Total	**295.2**	**381.3**		**374.8**

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 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

A.1.1 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 £208.3m and overall capital expenditure £489.1m, excluding customer connections.

Table A.1 - DPCR3 Actual & Forecast Expenditure

	Actual			Forecast		Total
	2000/01	**2001/02**	**2002/03**	**2003/04**	**2004/05**	
Capital Expenditure						
Load Related						
Capital Contributions						
Net load related	33.2	44.9	41.1	41.8	47.3	208.3
Non Load Related	60.5	54.9	47.2	52.1	64.0	278.7
Non-operational capex	0.7	1.4	-	-	-	2.1
Total Capital Expenditure	94.4	101.2	88.3	93.9	111.3	489.1

The SEPD philosophy with regard to forecasting load and non-load expenditure is covered in the following policy documents provided by SEPD.

- Underground cable refurbishment strategy
- Rising mains refurbishment
- Load related reinforcement (Major Projects at Primary level and above)
- Non Load related refurbishment (Major Projects at Primary level and above)
- HV Ground mounted substation refurbishment strategy
- EHV/HV/LV Overhead Line refurbishment strategy
- Wayleave terminations

The Base Case Projected Capital Expenditure follows the Ofgem FBPQ guidelines and is summarised in Table A.2 below.

Table A.2 - DPCR4 Base Case Capex Forecasts

	Forecast					Total
	2005/06	2006/07	2007/08	2008/09	2009/10	
Capital Expenditure						
Load Related						
Capital Contributions						
Net load related	41.3	41.3	41.3	41.3	41.3	206.5
Non Load Related	79.2	78.9	77.2	76.7	75.9	**387.9**
Non-operational capex	1.0	1.0	1.0	1.0	1.0	**5.0**
Total Capital Expenditure	121.5	121.2	119.5	119	118.2	**599.4**

Note that the above figures are presented without normalisation.

A.1.2 Projections of future load related capex

SEPD's load related capital expenditure projections for the Base Case Scenario are as set out in Table A.3 below:

Table A.3 - Base Case Forecast

LOAD RELATED CAPITAL EXPENDITURE £M	2005/06	2006/07	2007/08	2008/09	2009/10
Reinforcement	Breakdown was not provided by SEPD				
New Connections					
LRE Total Gross					
Customer Contributions					
LRE Total Net	41.3	41.3	41.3	41.3	41.3

A.1.2.1 Network reinforcement

In SEPD the SCADA system provides actual maximum demand, time and date of maximum demand for each circuit i.e. 11, 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 SEPD 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. The forecast thus obtained is compared with the forecast from the previous year to identify any step changes in demand. Any such step changes are rationalised to produce a credible future forecast.

To derive a forecast at the 132/33 kV substation level SEPD aggregate the maximum demand of all primary substations associated with a bulk supply point (BPS). The aggregated maximum demand of the current year is also compared with the actual maximum demand obtained via SCADA at the BSP. The ratio of actual maximum demand to aggregated maximum demand provides a diversity factor that is used to convert aggregated maximum demand to simultaneous maximum demand (SMD). The SMD is used to determine compliance with ER P2/5.

Table A.4 - SEPD Simultaneous Maximum Demand Forecast

	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
SMD (MVA)	6577	6711	6861	7010	7165	7320	7479	7644

SEPD has identified two major 132kV reinforcement schemes planned to be undertaken during DPCR4, namely reinforcement of the:

- Fleet – Basingstoke – Reading 132kV system at an estimated cost of about £20.1m in DPCR4 and

- Mannington – Poole – Shaftesbury – Salisbury 132kV system at an estimated cost of about £13.5m.

In the SEPD area there are some 80 bulk supply substations. SEPD states that, according to the demand forecast carried out in 2002/03, at 15 of these substations the security of supply criterion for group demand would be non compliant under first and/or second circuit outages for the period 2005/06 to 2009/10. These are listed in Table A.5 below.

Table A.5 - SEPD Bulk Supply Substation Reinforcement Forecast

Name	Voltage	Likely incidence of expenditure
Aldershot	132/33kV	2005/06
Chalvey	132/33kV	2006/07
Toothill	132/33kV	2007/08
Winchester	132/33kV	2006/07
Wareham	132/33kV	2009/10
Portsmouth	132/33kV	2006/07
Drayton	132/33kV	2009/10
Rownham	132/33kV	2008/09
Velmore	132/33kV	2008/09
Iron Bridge	66/11kV	2009/10
Bournemouth	132/33kV	2008/09
East Bedfont	132/11kV	2005/06
Hunston	132/33kV	2007/08

Name	Voltage	Likely incidence of expenditure
Marchwood	132/11kV	2008/09
Yeovil	132/33kV	2007/08

Furthermore there are over 500 primary substations and the 2002/03 demand forecast shows that during DPCR4 some 40 substations will exceed their firm capacity and will require reinforcement.

Table A.6 - SEPD Primary Substation Reinforcement Forecast

Name	Voltage	Likely incidence of expenditure
Yetminster	33/11kV	2006/07
Netley Common	33/11kV	2005/06
Tadley	33/11kV	2005/06
Bicester	33/11kV	2006/07
Wotton Road	33/11kV	2007/08
Rissington	33/11kV	2008/09
Chipping Norton	33/11kV	2007/08
Yarnton	33/11kV	2005/06 (over two years)
Harvard Lane	22/11kV	2009/10
Hindhead	33/11kV	2006/07 (over two years)
Milford	33/11kV	2005/06
Overton	33/11kV	2009/10
Ascot	33/11kV	2005/06
Elms Road	33/11kV	2006/07 (over two years)
Cove	33/11kV	2009/10 (over two years)
Crowthorne	33/11kV	2005/06
Crookham	33/11kV	2009/10
Hitches Lane	33/11kV	2008/09
Wrecclesham	33/11kV	2008/09
Reading Town	33/11kV	2005/06
Farnham Royal	33/11kV	2007/08
Taplow	33/11kV	2007/08
Market	33/11kV	2006/07 (over two years)
Hoeford	33/11kV	2007/08
North Fareham	33/11kV	2006/07
Brockhurst	33/11kV	2005/06

Name	Voltage	Likely incidence of expenditure
Leigh Park	33/11kV	2009/10
Gamble Road	33/11kV	2007/08
Waterlooville	33/11kV	2005/06 (over two years)
Mannington	33/11kV	2005/06
Petersfinger	33/11kV	2009/10

Name	Voltage	Likely incidence of expenditure
Salisbury Central	33/11kV	2007/08
Wareham Town	33/11kV	2008/09
Holwell	33/11kV	2005/06
Devizes	33/11kV	2005/06
Dorcan South	33/11kV	2005/06
Romsey	33/11kV	2008/09
Chapel	33/11kV	2008/09
Velmore	33/11kV	2009/10
Harestock	33/11kV	2009/10

The thermal capability of individual plant and circuits is defined at the time of its commissioning. This assigned capability is based on a number of factors such as seasonal capability, cyclic nature of demand, construction details and capability of associated ancillary equipment. As the demand on this plant and equipment normally increases each year SEPD undertakes a high-level system analysis to identify overloaded plant, equipment and circuits, these are recorded in the SEPD ComPlan system.

As the demand on plant and equipment normally increases each year SEPD undertakes a high-level system analysis to identify overloaded plant, equipment and circuits. Based on the 2002/03 demand forecast and power system analysis under N-1 and N-2 (as appropriate) SEPD estimates that, in addition to the 132kV systems, BSPs and primary substations already mentioned, some twenty eight 33 kV circuits and two 33/11 kV transformers will become overloaded during DPCR4.

Table A.7 - SEPD 33kV Circuits requiring Reinforcement Forecast

Circuit	Voltage	Incidence of expenditure
Bracknell – Sunninghill – Chobham	33kV	2006/07 and 2007/08
Leafield – Rissington	33kV	2005/06
Leafield – Witney	33kV	2006/07
Startton 33kV circuits	33kV	2006/07 and 2007/08
Yarnton 33kV circuits	33kV	2007/08 and 2008/09
Berinsfield 33kV circuits	33kV	2006/07
Amesbury – Ratfyn 33kV circuit	33kV	2005/06
Shaftesbury – West Stour	33kV	2005/06
Bournemouth – Parkstone	33kV	2008/09 and 2009/10
Shaftesbury – Shroton	33kV	2005/06 and 2006/07
Chippenham – Calne	33kV	2005/06
Overton – Basingstoke	33kV	2008/09 and 2009/10
Thatcham – Ball Hill	33kV	2005/06
Reading – Henley – Kidmore End	33kV	2005/06
Andover East – Barton Stacey	33kV	2005/06
Pangbourne – Burghfield	33kV	2005/06
Pangbourne – Streatly	33kV	2007/08
Winterborne Abbas – Charminster	33kV	2006/07
Hawley – Camberley	33kV	2008/09 and 2009/10
Frome – Westbury	33kV	2007/08 and 2008/09
Yeovil – West Hendford	33kV	2009/10
Fernhurst – Petersfield	33kV	2006/07
Thatcham – Hungerford	33kV	2007/08
Fernhurst – Langley Court	33kV	2006/07
Frome – Crockerton	33kV	2006/07
Alton – Basingstoke	33kV	2006/07
West Grafton – Pewsey – Marlborough	33kV	2009/10
Leckhemstead – Lamborne	33kV	2007/08

Table A.8 - SEPD Primary Transformer Reinforcement Forecast

Primary Transformer	Voltage	Incidence of expenditure
Little Marlow	33/11 kV	2005/06 (Transformer Overload)
Bracknell	33/11 kV	2008/09 (Transformer Overload)

The plant and equipment installed on the distribution system that is required to make or break fault current are assigned fault ratings, typically manufacturers design ratings. Fault levels can change on distribution systems for the following reasons:

- Modification or change to the transmission system
- Change and/or installation of new equipment that results in reduction in the system impedance
- Reconfiguration of the distribution system.
- Connection of embedded generation

SEPD has examined its network and has identified the following sites where switchgear will require replacement due to fault levels:

Table A.9 - SEPD Overstressed Switchgear Forecast

Name	Voltage	Incidence of expenditure
Cowley Local	33kV	2005/06
Fawley North	11kV	2008/09
Norrington	33kV	2008/09
Hillingdon	11kV	2009/10
Perivale	11kV	2007/08
Northolt	11kV	2006/07
Mannington	33kV	2007/08
Alton Local	11kV	2005/06
Fryers Lane	11kV	2007/08
High Wycombe Town	11kV	2006/07
Maidenhead	11kV	2007/08
Petersfield	11kV	2009/10
Redhill	11kV	2006/07
Silver Street	11kV	2005/06
Yeovil	11kV	2008/09
Western Esplanade	11kV	2005/06

A.1.2.2 New connections forecast expenditure

A new business request can result in reinforcement of the primary distribution system. The cost of such reinforcement is either charged to the customer or is picked up as system reinforcement cost. The customer is normally not charged the cost of reinforcement under the following cases:

- If the customers demand is less than 25% of the effective capacity at the point of connection.
- If the reinforcement is more than one voltage above the voltage at the point of connection.
- If the reinforcement is already identified before the new business request. In such cases the customer may be charged the brought forward cost to meet customers specific needs.

SEPD has commented that it is difficult to forecast where a single new connection would result in reinforcement of a substation. However, as the forecast demand at each substation captures known schemes, the capital expenditure needed during DPCR4 is largely reflected in the SEPD submission.

SEPD has indicated that on its network there are no known areas where voltage is likely to be outside statutory limits during DPCR4.

At the start of DPCR3 SEPD changed the set-up of its new connection business to a ‘ring fenced’ business within SEPD. The business is incentivised to increase profit through efficiency gains and hence minimise the amount of capital required from the ‘wires’ business. The connections business has been combined into one managed unit within the SSE Group (Scottish Hydro-Electric and Southern Electric). The result of this is that SEPD has not included new connections or customer contributions in its submission.

We consider the basis of the load related expenditure forecast to be sound as it relies on well established demand forecasting techniques and power system studies that identify site-specific reinforcement requirements.

A.1.2.3 Non-Load related expenditure

The breakdown of non-load related expenditure projected by SEPD for the Base Case Scenario is shown in Table A.10 below:

Table A.10 - SEPD Non-load Related Capex

	2005/06	2006/07	2007/08	2008/09	2009/10	Total
Non Fault Replacement	61.8	62.2	60.7	60.9	61.0	**306.5**
Metering	6.7	5.6	5.3	4.6	3.6	**25.8**
Faults	7.8	8.1	8.2	8.2	8.3	**40.5**
Diversions	0.0	0.0	0.0	0.0	0.0	**-**
Health and Safety	1.3	1.3	1.3	1.3	1.3	**6.6**
Environmental	1.7	1.7	1.7	1.7	1.7	**8.5**
Total	**79.2**	**78.9**	**77.2**	**76.7**	**75.9**	**387.9**

A.1.2.3.1 Non fault replacement

The main drivers for non-load related capital expenditure in SEPD are:

- Asset Condition
- Network Security
- Fault Performance
- Spares and Obsolescence
- Safety
- Age

SEPD prepares a five-year non-load related capital expenditure plan that is primarily based on asset age and comparison with assigned useful asset life. Other information such as external and internal condition and known design problems is used to prioritise the five-year plan. A yearly non-load related budget is created using the information in the five-year plan and actual asset condition information from the field. The SEPD decision making process, which is based on a scoring method that takes in to account the five main drivers listed above, includes whether to replace, refurbish or carry out additional maintenance.

A comparison of asset lives shows that SEPD’s asset lives for plant and equipment are:

- About average for switchgear
- Among the oldest for transformers
- Slightly older than the average for underground cables

The increase in expenditure in substation, overhead lines and underground cables proposed by SEPD for DPCR4 over DPCR3 would appear to be driven substantially by the age profiles of plant and equipment as well as the policy of rebuilding quantities of HV and LV lines with covered conductors.

Following a comprehensive assessment of system risks, and using a Reliability Centred Maintenance (RCM) approach, SEPD has developed procedures for inspection, maintenance and refurbishment of overhead lines. From the analysis SEPD has chosen a 12-year cycle refurbishment that also has the financial and efficiency benefit of aligning with a 4-year cycle for inspection.

The SEPD non-fault replacement capex is broken down as shown in Table A.11 below:

Table A.11 - Non Fault Replacement Capex Forecast

Expenditure Classes	Non-Load Related (£m)					
	2006	2007	2008	2009	2010	Total
Substations	22.6	22.6	22.6	22.6	22.6	**113.0**
Overhead lines	18.5	18.5	18.5	18.5	18.5	**92.4**
Underground cables	17.2	17.0	16.9	17.0	17.0	**84.9**
Submarine cables	-	-	-	-	-	**-**
Service lines and cables	0.4	0.4	0.4	0.4	0.4	**2.1**
Meters	6.7	5.6	5.3	4.6	3.6	**25.8**
Tele-control / SCADA	1.3	1.3	1.3	1.3	1.3	**6.5**
Easement expenditure	0.7	0.7	0.9	1.0	1.2	**4.5**
Lane rentals	-	-	-	-	-	**-**
Other operational capital expenditure	1.1	1.7	0.1	0.1	0.1	**3.1**
Total Non Operational	-	-	-	-	-	**-**
Total	**68.4**	**67.8**	**66.0**	**65.5**	**64.6**	**332.3**

Table A.11 includes £25.8m for meters, which when subtracted from the total non fault replacement capex of £332.3m, gives £306.5m non-fault replacement as shown in Table A.10.

Reconciliation with Table 3.3. Table A.11 total of £332.3m less (£25.8m (meters) and £6.5m (SCADA)) plus (£6.6m (health and safety) and £8.5m (environmental) gives £315.1m (Table 3.3).

The three major areas of non-fault replacement in SEPD are substations, overhead lines and underground cables; these areas are further discussed below.

A.1.2.3.2 Substation non-fault replacement

The classification of substations includes mainly switchgear and transformers. The forecast replacement volumes of switchgear and transformers is shown in Table A.12 below:

Table A.12 - SEPD Forecast Replacement Volumes of Transformers & Switchgear

Asset Type	Voltage	Total Volume	Replacement Volume	% of Total Volume Replaced
Transformers	132/33kV	230	15	6.5
	33/11 kV	869	80	9
Total transformers		1099	104	9.5
Switchgear				
	132kV	260	20	7.7
	66kV	60	15	25
	33 and 22kV	1416	65	4.5
	11kV switchboards	450	30	6.7
Total Switchgear		2186	130	6

The replacement rates of 9.5% for transformers and 6% for switchgear are consistent with the SEPD risk assessment replacement process and are indicative of very long asset lives. We would consider these replacement proposals to be reasonable.

A.1.2.3.3 Overhead lines non-fault replacement

The SEPD proposals for overhead line investment are based on the refurbishment cycle of 12 years for all overhead lines as indicated above plus short-term actions to ensure that the risk of incident or loss of supply is managed to within acceptable levels during DPCR4. The capex proposals are based on a consideration of the following areas:

- Storm resilience
- New requirements driven by changes to the ESQC Regulations
- High Risk Sites
- “Rutter Pole” circuits
- LV Lines

In order to counter marginally deteriorating fault rates and to improve resilience, SEPD plans to rebuild/reconductor some 550km of HV overhead line with insulated BLX conductor (£21.5m) and some 950km of LV line with ABC (£24.7m), under the Base Case.

SEPD considers that the introduction of the Electricity Safety, Quality and Continuity Regulations 2002 (ESQCR) has introduced a number of new duties for DNOs. In particular, the new regulations have driven the need for additional investment to address two new requirements:

- Existing bare LV conductors within 3m of habitation will require to be replaced with insulated conductor or ABC. SEPD estimates expenditure of £1.04m per annum (£5.2m in total for DPCR4) corresponding to 200km of LV line, based on a 10 per cent sample

- All overhead lines and substations require risk assessment and the results catalogued on a new database. SEPD estimate that over DPC4 the risk assessment and database establishment will cost £1.5m. In addition an annual expenditure of £750k per annum will be required to address the risks identified by the risk assessment, particularly at leisure sites including playfields, camping areas and fishing areas

- A further £2.5m of expenditure is concerned with other safety related issues addressing low primary substation fences, earthed air break switches and pole mounted recloser earthing which have recently emerged as problems.

Other measures include light refurbishment at all voltage levels as well as some major EHV refurbishment. SEPD has indicated that the proportions of replacement (major refurbishment) by volume of overhead lines are LV (19.6 per cent), HV (7 per cent), EHV (0 per cent) and 132kV (100 per cent).

Overall non-load related expenditure on overhead lines, including fault and health and safety expenditures, averages £19.9m per year.

A.1.2.3.4 Underground cables non-fault replacement

SEPD indicates that expenditure on underground cables is forecast to increase from DPCR3 levels to a level of about £17m per year, excluding faults, in DPCR4. This increase reflects deteriorating fault rates that will be addressed on an ad hoc basis. The SEPD proposals for underground cable replacement include the following:

- Replacement of Iver to Hillingdon 66kV cables which are part gas filled and part solid construction and have a history of failures

- Replacement of 33kV HSL cables in the Southampton area; the cables concerned are of small cross section, have lower fault ratings and there is evidence of drying of papers resulting in discharge

- 11kV cables where these have a high fault rate

- LV consac cable where there are continued problems with resin joints, involving an annual expenditure of £11m covering the application of both “fasttrack” and overlay methods.

SEPD has also identified some 132kV gas compression cables and one of the 132kV 3-core fluid filled submarine cables under the Solent as candidates for replacement in the next ten years. In addition the company has also made provision to prevent and contain leaks on fluid filled cables. We would comment that as such cables are expensive items, expenditure can exhibit volatility.

Overall SEPD provided the following breakdown of its forecast expenditure on refurbishment of underground cables (the itemised costs include fault repairs).

Table A.13 - SEPD Forecast of Capex on Underground Cable Refurbishment

Voltage	Length (km)	Forecast expenditure (£m)
132kV	10	11.9
66kV	2	2.2
33kV	76	13.7
11kV	77	8
Other LV	188	34.6
Consac LV	265	48.6
Submarine		2
Total, including faults		121
Total, excluding faults		113

We consider the basis of the non-load related expenditure forecast to be sound as it relies on well-documented policies and structured risk, RCM and condition processes that identify asset specific replacement requirements.

APPENDIX B

QUALITY OF SUPPLY SCENARIOS

APPENDIX B – QUALITY OF SUPPLY SCENARIOS

B.1.1 Network performance improvements

The following table sets out the proposed network performance targets for 2010 and 2020.

Table B.1 - Proposed Network Performance Targets

02/03 actual		01/02 & 02/03 ave		2010 Scenario		2020 Scenario		(ave/2010)%	
CI	CML	CI	CML	CI	CML	CI	CML	CI	CML
87.9	73.4	92.4	82.7	84.4	74.0	72.5	60.9	109%	112%

Note: The above CIs and CMLs are unplanned CIs and CMLs.

B.1.1.1 Quality of supply – improvement scenario

SEPD has proposed a combination of measures for improvements during DPCR4 as summarised in Table B.2 below.

Table B.2 - Quality of Supply Improvement Measures

Measure	Quantity	Expenditure (£m)	CI improvement	CML improvement
BLX rebuilds (km)	916	35.8	1.05	1.45
Undergrounding 11kV lines (km)	320	20.9	0.36	1.0
Feeder splitting (circuits)	80	26	1.95	1.2
Rural automation (circuits)	480	9.2	2	4.5
Consac overlay (km)	248	42.8	0.88	2
Underground distribution boxes (units)	1250	6.5	0.1	0.83
Total		141.2	6.34	10.98

SEPD indicates that its level of unplanned CIs for 2009/10 would be 83.6 (i.e. slightly better than the Ofgem target) and its unplanned CMLs 74.0 (the Ofgem target). The company also points out that CIs and CMLs are related and that by improving CIs, CMLs would be improved as part of the process.

We would consider the headline cost of about £260 per annual customer hour saved as being on the high side, but not necessarily untypical.

B.1.1.2 Quality of supply – sensitivities

SEPD has proposed the following measures to meet the sensitivity cases.

B.1.1.2.1 Improvements in CI and CML performance sensitivities relative to central quality scenario

Table B.3 - Sensitivity 3 - CI Performance Reduced 2% Relative to Central Quality Scenario

Measure	Quantity	Expenditure (£m)	CI improvement	CML improvement
BLX rebuilds (km) – additional to central Quality scenario	843	32.9	0.96	1.33

The forecast CI gain is however less than 2% relative to the central quality scenario.

Table B.4 - Sensitivity 5 - CML Performance Reduced by 5% Relative to Central Quality Scenario

Measure	Quantity	Expenditure (£m)	CI improvement	CML improvement
BLX rebuilds (km) – additional to central Quality scenario	1263	49.26	1.5	2.0
Consac overlay (km) – additional to central Quality scenario	496	85.6	0.88	2.0
Total) – additional to central Quality scenario		134.86	2.38	4

SEPD comments that following the rural and urban automation expenditure in the central quality scenario, additional expenditure would not be economic.

The forecast CI and CML gains would meet the sensitivity 3 and sensitivity 5 requirements respectively.

B.1.1.2.2 Deteriorations in CI and CML performance sensitivities relative to central quality scenario

Table B.5 - Sensitivity 2 - CI Performance Increased 2% Relative to Central Quality Scenario

Measure	Quantity	Expenditure (£m)	CI improvement	CML improvement
Rural automation (circuits) – additional to Base Case	480	9.2	2	4.5
Feeder splitting (circuits) – additional to Base Case	80	26	1.95	1.2
Total) – additional to Base Case		35.2	3.95	5.7

The CI improvement would meet the sensitivity 2 requirement (84.4 plus 2%) which would correspond to an improvement of 3.91 CIs over the 2004/05 level of 90 CIs.

Table B.6 - Sensitivity 4- CML Performance Increased 5% Relative to Central Quality Scenario

Measure	Quantity	Expenditure (£m)	CI improvement	CML improvement
Rural automation (circuits) – additional to Base Case	480	9.2	2	4.5
Feeder splitting (circuits) – additional to Base Case	80	26	1.95	1.2
Consac overlay (km) – additional to Base Case	96.7	16.7	0.34	0.78
Underground distribution boxes (units) – additional to Base Case	1250	6.5	0.1	0.82
Total) – additional to Base Case		58.4	4.39	7.3

The CML improvement would also meet the sensitivity 4 requirement (74 plus 5%) that would correspond to an improvement of 7.3 CMLs over the 2004/05 level of 85 CMLs.

B.1.1.3 Accelerated line upgrade

SEPD believes that its existing HV lines are essentially to EATS 43-40 standard. 30 per cent of these lines are of BLX covered conductor construction. For the purposes of this scenario, SEPD proposes to rebuild an additional 20 per cent of its lines with BLX. This represents an additional 2080km over and above the Base Case Scenario costing £81m and providing an estimated 2.08CI and 3.29CML benefit.

B.1.1.4 Undergrounding existing overhead lines (network resilience)

In order to underground 2% of its HV overhead network SEPD would need to address around 268km of lines at a cost of approximately £17.61m. As well as giving resilience benefits SEPD estimates that this scenario would improve network performance by about 0.84 CML and 0.3 CI. This response however raises the question as to how resilience improvements should be evaluated.

B.1.1.5 Undergrounding existing overhead lines (amenity value)

To underground all overhead lines within National Parks and Areas of Outstanding Natural Beauty SEPD estimates a cost £359.9m to underground some 2766km of lines at all voltage levels.

APPENDIX C

DNO ALTERNATIVE SCENARIO

APPENDIX C – DNO ALTERNATIVE SCENARIO

The SEPD alternative case includes the following areas, some of which are already included in the Base Case:

- Network resilience and performance
    - an additional 550km of replacement of HV lines with BLX covered conductor construction (£21.5m) over the Base Case to improve resilience further
    - fitting of pole-mounted auto-reclosers and automatic sectionalising links to bare conductor HV circuits as well as splitting of urban and rural feeders to address the concentrations of customers at "tail ends" (£18.6m)
    - undergrounding 210km of overhead lines (£13.8m)
- switchgear replacement (£71m), transformer replacement (£48m)
- Environmental factors including oil containment (£15m)
- ESQC Regulations (£6.7m + £2.5m)
- Lane rentals (As requested by Ofgem SEPD has not included any costs in the business plan for lane rentals, although an annual increase of £17m (£11m on opex and £6m on capex is indicated by SEPD)
- Consac LV cable (£46m)

The total additional cost of the SEPD alternative scenario over the Base Case is £54m, an increase of 9 per cent and £653.5m in total, and is related principally to the network resilience and performance areas. A CI improvement of 3.5 and a CML improvement of 6 as well as resilience improvements are claimed.

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.

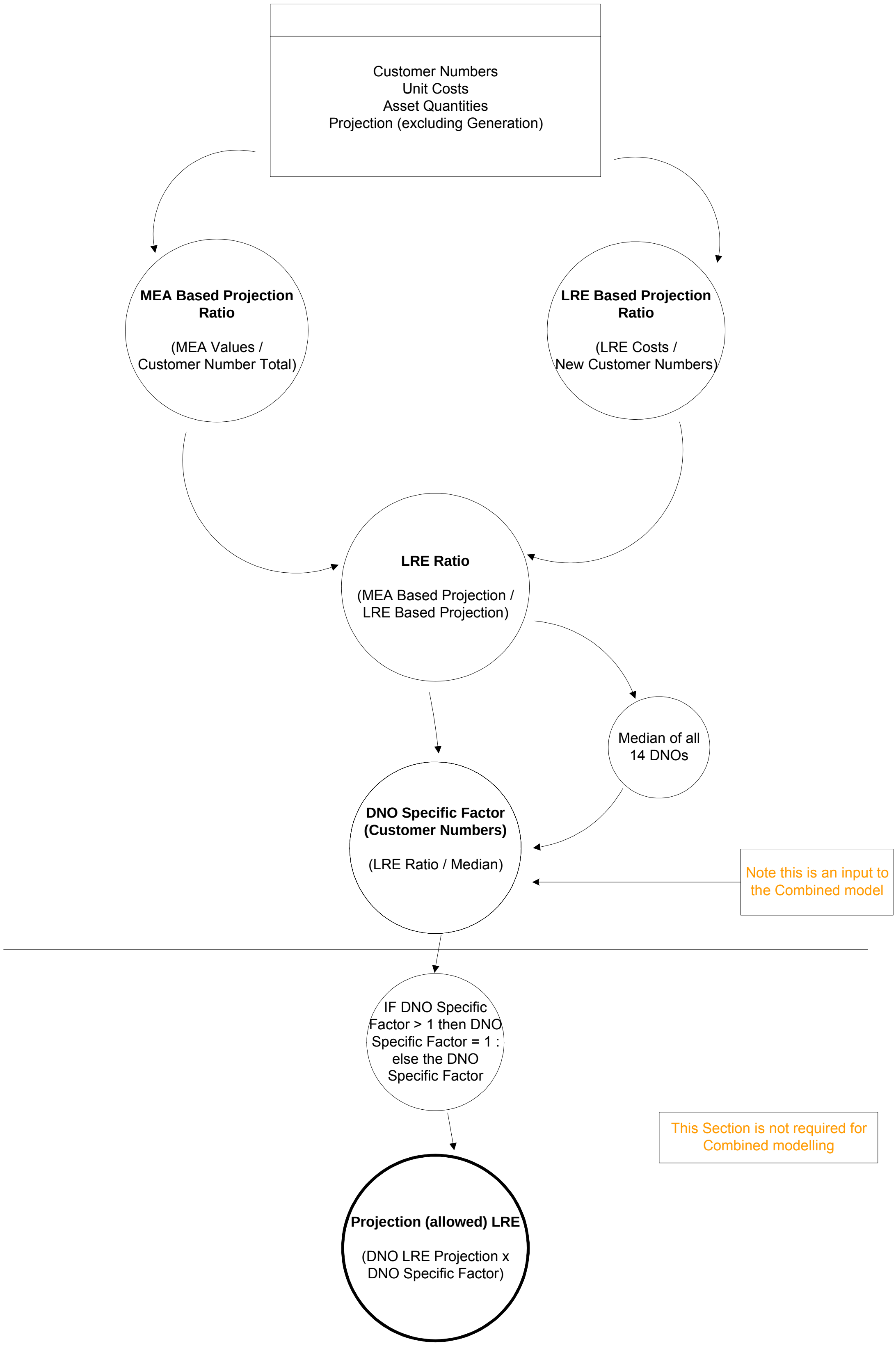
Being benchmarked on a median rather than on an average implies that extremes do not affect the adopted benchmarking position. It also means that the LRE of each company is compared relative to its cost base against the Industry Trend and not in absolute cost terms. This approach recognises therefore 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

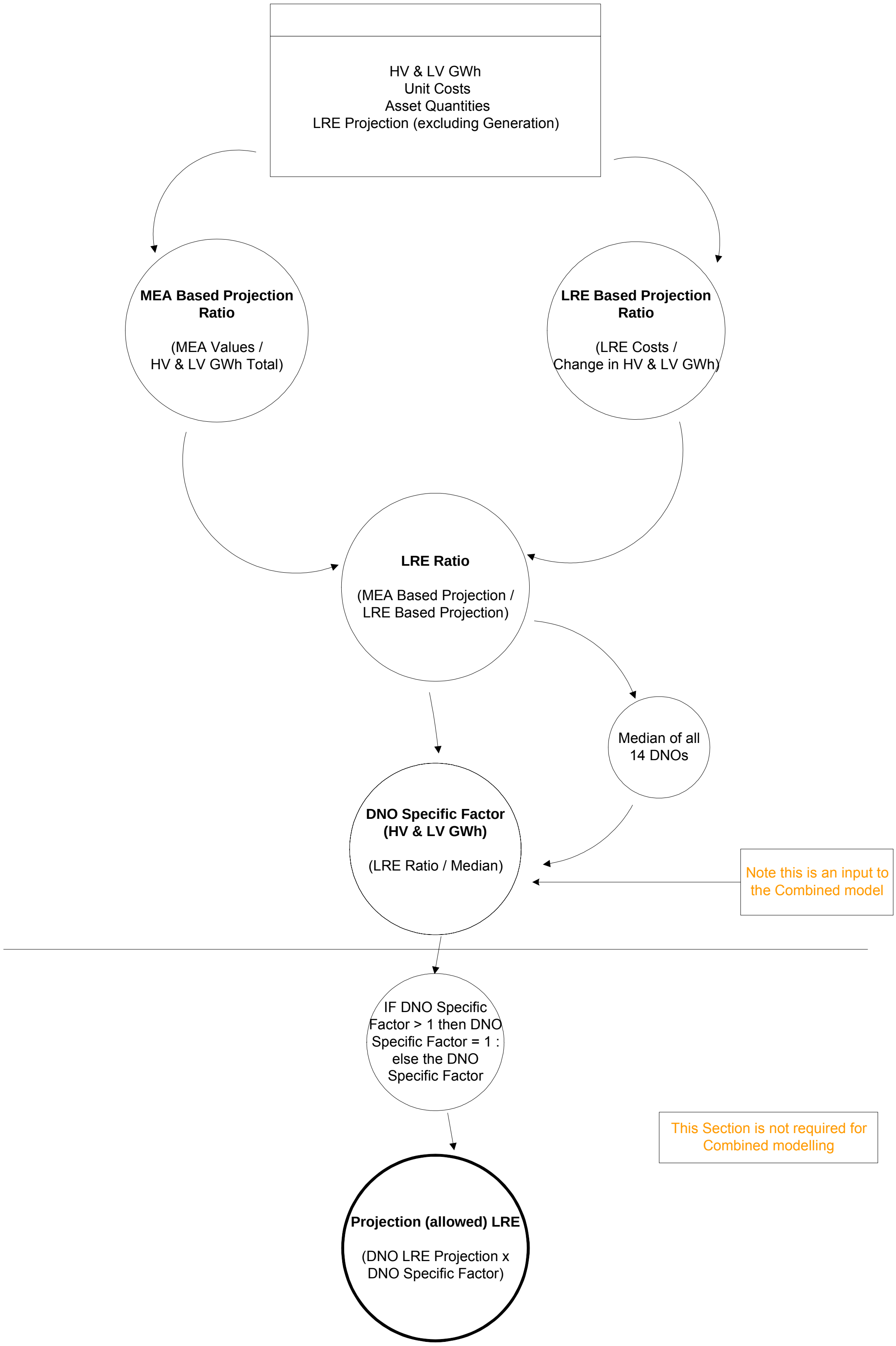
Although each DNO's network is comprised of a large number of smaller networks and that it would be expected that these would have a range of spare capacities depending on local load growth and when individual networks were last reinforced, it is possible that a larger number of the smaller networks 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.

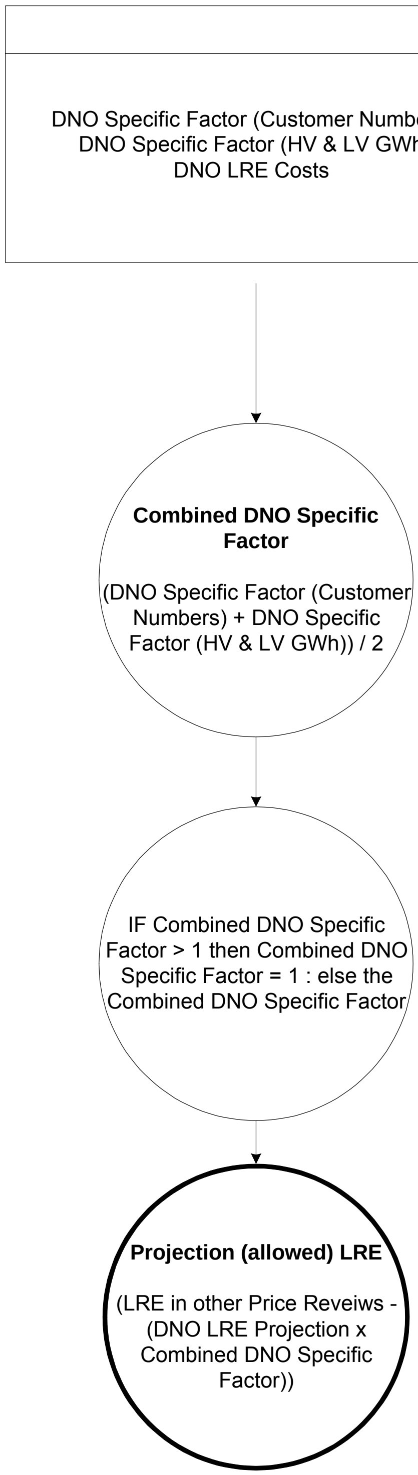
Combined Load Related Expenditure Modelling (Phase 1A Customer Numbers)



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.1.1 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.1.2 Gross Value Added (GVA)

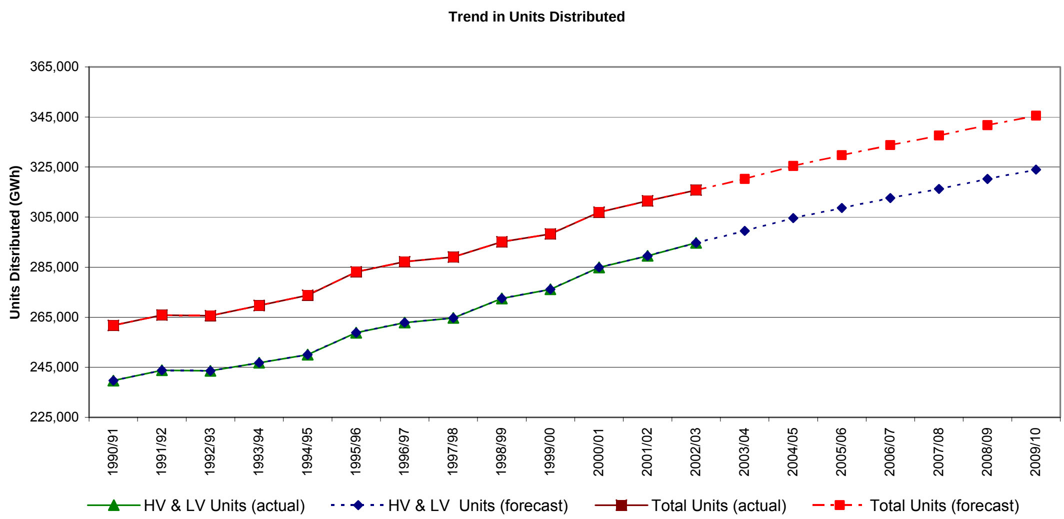
For the purposes of this review, GVA is treated as being synonymous with gross domestic product (GDP). Furthermore Regional Accounts are currently published in terms of GVA1 only. Statistics are published by geographical region in accordance with the Nomenclature of Units for Territorial Statistics (NUTS) 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.

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

Trend of energy distributed against time.



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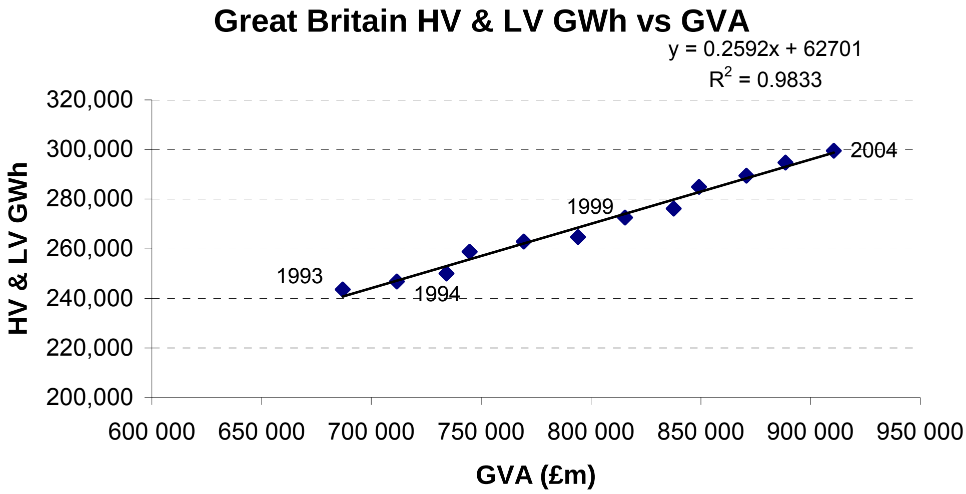
[1] Office of National Statistics: Local area and sub-regional gross domestic product, 26 April 2001, www.statistics.gov.uk

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.1.3 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.1.4 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 20043 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.

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[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.1.5 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.1.1 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:

v. age profile

vi. retirement profile and

vii. 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

a. **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.

b. **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.

c. 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.

d. 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

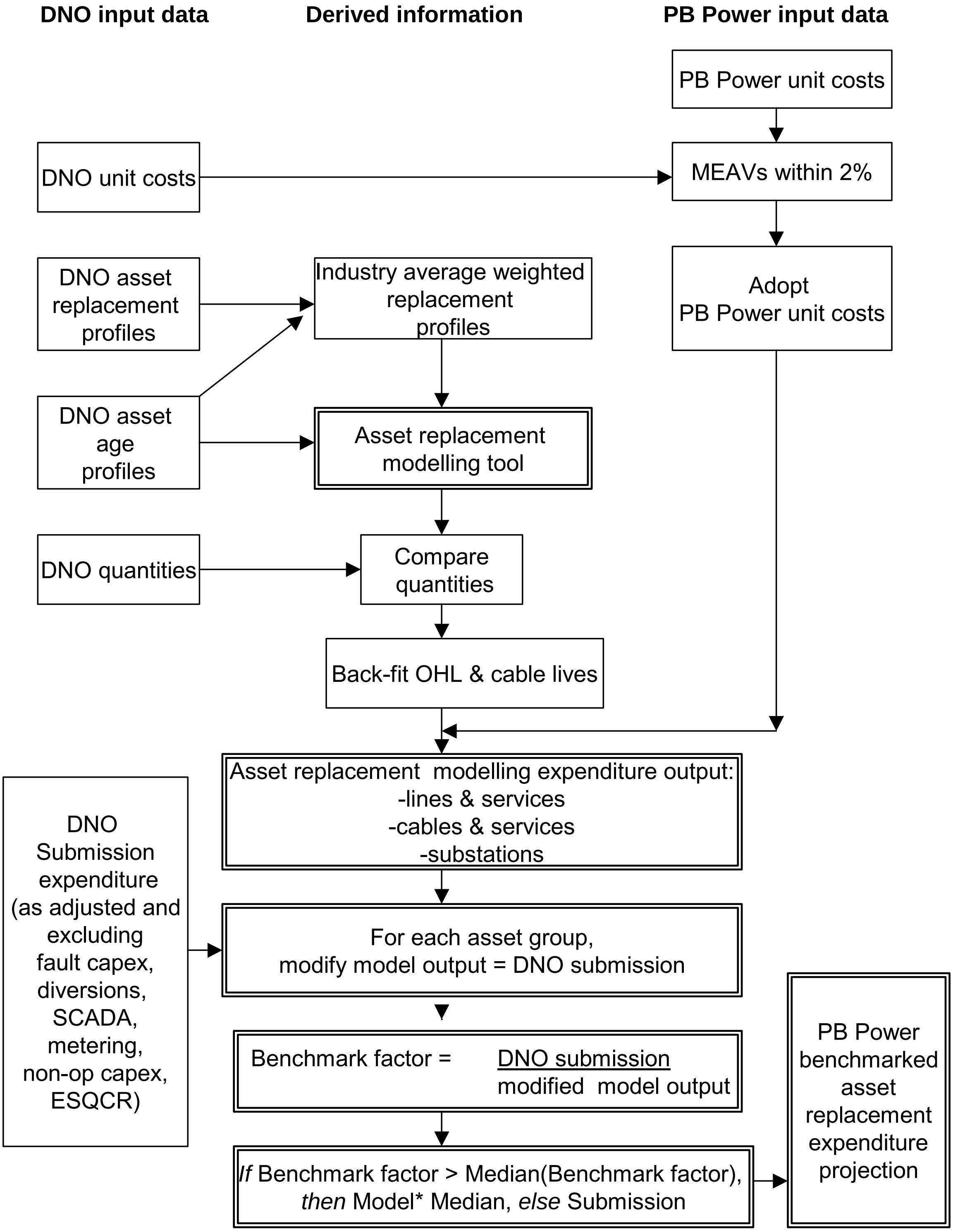
The model output is initially modified so that for each of the asset groups the overall industry (14 DNOs') expenditure predicted by the model is the same as that forecast by the DNOs. (The differences had in any case been small.) For each asset group, benchmark factors of DNO submission/model output 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
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
- 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%