OFGEM

WPD SOUTH WEST

DPCR4 – FBPQ ANALYSIS AND CAPEX PROJECTIONS

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CONTENTS

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)
SSAP	Standard accountancy practice
WPD	Western Power Distribution

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 and network resilience to storms. 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.

Notwithstanding previous comments on Base Case expenditure and network risk, where allowances has been based on modelled outputs, then the expenditure allowed should achieve the same level of network risk for all DNOs both for LRE and NLRE expenditure.

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 WPD South West's adjusted DPCR3 projection, adjusted DPCR4 forecast, PB Power's modelling results and opinion 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	126.1	154.4	154.4	154.4	The model output indicates the same level of gross load-related expenditure as in WPD South West's submission.
Customer Contributions	(63.6)	(79.7)	-	(79.7)	
LRE Net	**62.5**	**74.7**	**-**	**74.7**	
Asset Replacement	151.1	196.5	196.4	181.2	The model's prediction and WPD South West's forecast for substation and cable expenditures are virtually the same, after taking corporate overheads into account. For overhead lines and services, particularly HV lines, the model is predicting higher expenditures. PB Power's opinion is that an adjustment is required of £13.7m in respect of replacement of LV bare conductor lines that would have been incurred had the ESQCR not been introduced.
Other	73.1	111.1		111.1	£111.1m comprises diversions (£13.5m), meters (£18.3m) and fault replacement (£79.3m), but excludes ESQCR related expenditure.
NLRE Total	**224.2**	**307.7**		**292.3**	
Non Operational	43.6	43.7		43.7	Not reviewed.
DNO Total	**330.3**	**426.1**		**410.7**	
DNO Total				*269.4*	*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 WPD South West forecasts have been subject to a small adjustment in respect of capitalised overheads.

Our principal findings are summarised below.

Load related expenditure

- Overall the DPCR4 forecast expenditure represents an increase on the forecast level for DPCR3. The 132kV and EHV expenditures forecast for 2005/06 and 2006/07 is higher than the general trend for this class of expenditure.

Non-load related expenditure

- WPD South West's non-load related capex submission exceeds both the DPCR3 allowance and projection.
- WPD South West's forecast includes about £29m for remedial action to LV bare conductor lines with inadequate clearances (ESQCR). We have excluded this expenditure from the Base Case but £13.7m has been added in respect of replacement of LV bare conductor lines that would have been incurred had the ESQCR not been introduced.
- High levels of cable fault repair capital expenditure are included in the DNO submission.
- The increase in non-load related expenditure for the DPCR4 forecast over the DPCR3 projection is largely due to the inclusion in the forecast of £29m for LV bare conductor lines and £21.1m for LV Consac cable replacement.

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 the report includes comparisons between DPCR3 allowances, DPCR3 projections and DPCR4 forecasts. Care needs to be taken in reviewing these figures in respect of the following:

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

Quality of supply scenarios

WPD South West has identified only one main work stream, namely refurbishment of overhead lines, to produce the central quality of supply improvements at a capital cost of £15.3m, but such refurbishment would produce negligible changes in CIs and CMLs.

WPD South West points out that it expects that there would be a marginal benefit in terms of multiple interruption performance and that a refurbished HV overhead line would be more resilient to severe weather. Neither improvement is quantified however.

In order to underground 2% of its HV overhead network WPD South West would need to address some 796km of lines at a cost of approximately £58.5m.

To underground all overhead lines within National Parks and Areas of Outstanding Natural Beauty, WPD South West estimates a cost of £1009.7m.

WPD South West's Base Case scenario caters for 2562km of HV overhead line refurbishment at an aggregate capital cost of £33.8m. To meet the accelerated overhead line up-rating target (to EATS 43-40) WPD South West proposes to refurbish additional 280km at a cost of £3.5m, all HV overhead lines being in accordance with EATS 43-40 by 2034/35.

DNO alternative case

WPD South West has proposed quality of supply improvement measures, development of distributed generation, costs of lane rental charges, amounting to some £66.4m of capital expenditure.

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

PB Power view on load related and non-load related allowances

Load related expenditure

The model output indicates the same level of gross load-related expenditure as in WPD South West's submission.

Non-load related expenditure

The model's prediction and WPD South West's forecast for substation and cable expenditure are virtually the same, after taking corporate overheads into account. For overhead lines, particularly HV lines, the model is predicting appreciably higher expenditures.

We have excluded the provision by WPD South West of some £29.1m in respect of remedial work on LV bare conductor lines with inadequate clearances in order to meet the requirements of the ESQCR as this matter is being considered separately by Ofgem. In PB Power's opinion an asset replacement expenditure of £181.2m would be appropriate. With the inclusion of diversions, metering and fault capital expenditure, the corresponding overall non-load related expenditure would be £292.3m. .

Quality of supply scenarios

We would however regard the cost (in terms of undiscounted capital expenditure) as being high relative to the benefit obtained, noting that only one generic improvement measure has been considered.

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

The above considerations would indicate that a net capital expenditure of £410.7m would be appropriate.

1. INTRODUCTION

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

- Part 1, covered the systems, processes, assumptions, asset risk management and data used by Distribution Network Operators (DNOs) to forecast capital expenditure and an analysis of variances and efficiency gains in the HBPQ period .

- This Part 2 report provides an analysis of forecast expenditure for the five year period to 31 March 2010 and builds on information obtained in Part 1 of the project.

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 unplanned customer interruptions) and ± 5% (on unplanned 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 s 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 a PB Power forecast using industry average weighted asset replacement profiles and 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.

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

WPD South West's approach to forecasting the capital expenditure projections in the Base Case has been:

- to base the load-related expenditure on
  - forecasts of new domestic customers derived from new housing starts
  - forecasts of small non-domestic customers derived from the historic trend with regional GDP growth and
  - reinforcement expenditure projected to meet a demand forecast based on regional GDP growth and
- in respect of non-load related expenditure, to
  - forecast the medium to long term replacement of assets using age-related modelling with the aim of maintaining asset reliability and condition and furthermore
  - undertake refurbishment of overhead lines, particularly replacement of wood poles, so as to remedy without delay such defects that are found by routine inspection.

The following table presents the adjusted 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	**168.8**	**126.1**	**154.0**	**0.0**	**154.0**
Non Load Related	**251.3**	**224.2**	**307.1**	**0.0**	**307.1**
Gross Capex less Non Op Capex	***420.1***	**350.3**	***461.1***	***0.0***	***461.1***
Non Op Capex (Not Assessed)	16.8	43.6	43.7	0.0	43.7
Total Gross Capex	**436.9**	**393.9**	**504.8**	**0.0**	**504.8**
Contributions	-67.1	-63.6	-79.5	0.0	-79.5
Net Load Related	**101.7**	**62.5**	**74.5**	**0.0**	**74.5**
Total Net Capex	**369.8**	**330.3**	**425.3**	**0.0**	**425.3**
Non Load Related Summary					
Replacement	202.5		163.4	13.7	171.1
ESQCR			29.0	-13.7	15.3
Heath & Safety			3.6	0.0	3.6
Environment			0.0	0.0	0.0
Sub Total - Model Comparison	**202.5**	**151.1**	**196.0**	**0.0**	**196.0**
Diversions	29.8	7.7	13.5	0.0	13.5
SCADA		0.1	0.0	0.0	0.0
Sub Total	***232.3***	***158.9***	***209.5***	***0.0***	***209.5***
Metering (Not Assessed)	19.0	20.3	18.3	0.0	18.3
Sub Total	***251.3***	**179.2**	***227.8***	***0.0***	***227.8***
Fault Capex (Not Assessed)		45.0	79.3	0.0	79.3
Non Load Related Total	**251.3**	**224.2**	**307.1**	**0.0**	**307.1**

A correction has been made to transfer £13.7m from ESQCR to Asset Replacement.

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)

Item	Adjustment to DPCR4 Forecast: Gross Market LRE Adjustment	Pension Funding Deficit	Capitalised Overhead	Inter-company Margin	Lane Rentals Adjustment	Adjusted DPCR4 Forecast
Gross Load Related	0.0	0.0	0.4	0.0	0.0	**154.4**
Non Load Related		0.0	0.6	0.0	0.0	**307.7**
Gross Capex less Non Op Capex	***0.0***	***0.0***	***1.0***	***0.0***	***0.0***	**462.1**
Non Op Capex (Not Assessed)						**43.7**
Total Gross Capex	**0.0**	**0.0**	**1.0**	**0.0**	**0.0**	**505.8**
Contributions	0.0	0.0	-0.2	0.0	0.0	-79.7
Net Load Related	**0.0**	**0.0**	**0.2**	**0.0**	**0.0**	**74.7**
Total Net Capex	**0.0**	**0.0**	**0.8**	**0.0**	**0.0**	**426.1**
Non Load Related Summary						
Replacement		0.0	0.5	0.0	0.0	177.6
ESQCR		0.0	0.1	0.0	0.0	15.3
Heath & Safety		0.0	0.0	0.0	0.0	3.6
Environment		0.0	0.0	0.0	0.0	-
Sub Total - Model Comparison		**0.0**	**0.5**	**0.0**	**0.0**	**196.5**
Diversions		0.0	0.0	0.0	0.0	13.5
SCADA		0.0	0.0	0.0	0.0	-
Sub Total		***0.0***	***0.5***	***0.0***	***0.0***	***210.1***
Metering (Not Assessed)		0.0	0.0	0.0	0.0	18.3
Sub Total		***0.0***	***0.5***	***0.0***	***0.0***	***228.4***
Fault Capex (Not Assessed)		0.0	0.0	0.0	0.0	79.3
Non Load Related Total		**0.0**	**0.6**	**0.0**	**0.0**	**307.7**
Total Adjustments	**0.0**	**0.0**	**1.0**	**0.0**	**0.0**	**1.0**

2.1.2 Base case submission

2.1.2.1 Load-related expenditure

Connections expenditure is based on forecasts of new domestic customers derived from new housing starts whereas the forecast of small non-domestic customers is derived from the historic trend with regional GDP growth. Other large connections are separately forecast based on developers' information. WPD comments that the historical correlation is not high and is dependent on MPRS data for connections. Following the separation of distribution and supply businesses, data on customer and units distributed based on the historical sector definitions of domestic, agricultural, commercial and industrial are no longer available.

Reinforcement expenditure is planned to meet a seven-year demand forecast based on regional GDP growth. An average annual growth rate of 1.67 per cent is forecast for DPCR4. The overall load forecast is disaggregated down to the 33/11kV busbar level. Network planning is undertaken to meet licence requirements.

Overall the DPCR4 forecast expenditure (gross and net of capital contributions) represents a slight increase on the corresponding actual and forecast level for DPCR3, new connections expenditure being lower and reinforcement expenditure higher reflecting that the 132kV and EHV expenditures forecast for 2005/06 and 2006/07 are higher than the general trend for this expenditure. This increase is partly due to the deferment of a 132kV reinforcement scheme in mid Devon, where there have been delays in obtaining planning consents.

We would consider the basis of the forecast of load-related expenditure to be reasonable.

2.1.2.2 Non-load related expenditure

Replacement of assets in the medium to long term is forecast using age-related modelling with the aim of maintaining asset reliability and condition. Refurbishment of overhead lines, particularly replacement of wood poles, is undertaken so as to remedy without delay such defects that are found by routine inspection. WPD South West has presented charts showing the 20-year long-term trend in asset replacement expenditure and evolution of average ages of the principal asset categories (slight decreases for switchgear, transformers, overhead lines, but a slowly increasing trend for underground cables – all voltages). WPD's asset management process is supported by the company's comprehensive asset management database, CROWN.

WPD South West is forecasting expenditure on asset replacement (non fault replacement, faults and health and safety) in DPCR4 to be £271.3m, an increase of about £70m on the actual and forecast expenditure for DPCR3. Some efficiency savings in respect of design, productivity and procurement savings are claimed, offset by increased charges due to pensions (SSAP24). The principal reasons for the forecast increase in asset replacement are an increase in asset replacement activity level in all asset categories, reflecting average asset ages, as well as legislative changes. In the latter case WPD South West has forecast capital expenditure of about £30m to undertake remedial work on some 1277km of LV bare conductor line where clearances to buildings are in some cases currently less than 2 meters. WPD has cited compliance with ESQCR 2002 and EATS 43-8, Issue 2 December 1988, Overhead Line Clearances, as being the principal drivers. (EATS 43-8 specifies a minimum clearance of 3 metres at this voltage. WPD South West has submitted to DTI a procedure for assessing the risk of LV open wire overhead lines near buildings. The £30m estimate is however based on a survey of only about 10 per cent of the LV network. Under ESQCR all DNOs are required by January 2008 to have compiled a list of outstanding lines and to have reviewed their plans to undertake remedial work.)

Subject to ongoing discussions between Ofgem and DTI in respect of compliance with ESQCR, we would consider the basis of the forecast of non-load related expenditure to be reasonable.

Details of WPD South West's submission with work programmes and estimated costs are set out in Appendix A.

2.2 Ofgem scenario/sensitivity analysis

Table 2.3 below sets out the proposed network performance targets for 2010 and 2020.

Table 2.3 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
78.6	50.9	88.1	61.7	84.9	65.9	80.0	65.9	104%	94%

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

WPD South West has identified only one main work stream, namely refurbishment of overhead lines, to produce the quality of supply improvements. WPD South West would refurbish a further 1150km of line at a cost of £15.3m but such refurbishment would produce negligible changes in CIs and CMLs, improvements in unplanned incidents being offset by a deterioration in planned incidents, both movements being slight.

WPD South West points out that it expects that there would be a marginal benefit in terms of multiple interruption performance and that a refurbished HV overhead line would be more resilient to severe weather. Neither improvement is quantified however.

We would however regard the cost (in terms of undiscounted capital expenditure) as being high relative to the benefit obtained, noting that only one generic improvement measure has been considered.

In order to underground 2% of its HV overhead network WPD South West would need to address some 796km of lines at a cost of approximately £58.5m. No improvement in CIs or CMLs has been claimed although WPD South West acknowledges that the undergrounding would result in a marginal improvement in resilience.

To underground all overhead lines within National Parks and Areas of Outstanding Natural Beauty, WPD South West estimates a cost of £1009.7m.

WPD South West's Base Case scenario caters for 2562km of HV overhead line refurbishment at an aggregate capital cost of £33.8m. To meet the accelerated overhead line up-rating target (to EATS 43-40) WPD South West proposes to refurbish additional 280km at a cost of £3.5m, all HV overhead lines being in accordance with EATS 43-40 by 2034/35. No corresponding improvement in CI or CML performance is claimed however.

Our detailed comments on WPD South West's response to the Ofgem Scenario/Sensitivity Analysis (including Quality of Supply, undergrounding and accelerated overhead line upgrade) are presented in Appendix B.

2.3 DNO alternative case

The WPD South West alternative case covers the following areas:

- Quality of supply
  - an additional 1150km of overhead line strengthening (£15.3m) over the Base Case to further reduce the number of unplanned incidents
- Connections of Distributed Generation (£16.3m offset by £8.2m capital contributions, a net increase of £8.1m)
- Network resilience – enhanced tree cutting resulting in additional operating expenditure
- Lane rental charges, allocated as an annual charge of
  - £4.8m to new connections, offset by an increase of £3.4m in connection charges (DPCR4 net increase £7m) and
  - £7.2m to cable replacement/repairs (DPCR4 increase £36m).

Our detailed comments on WPD South West's Alternative Scenario are presented in Appendix C.

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.

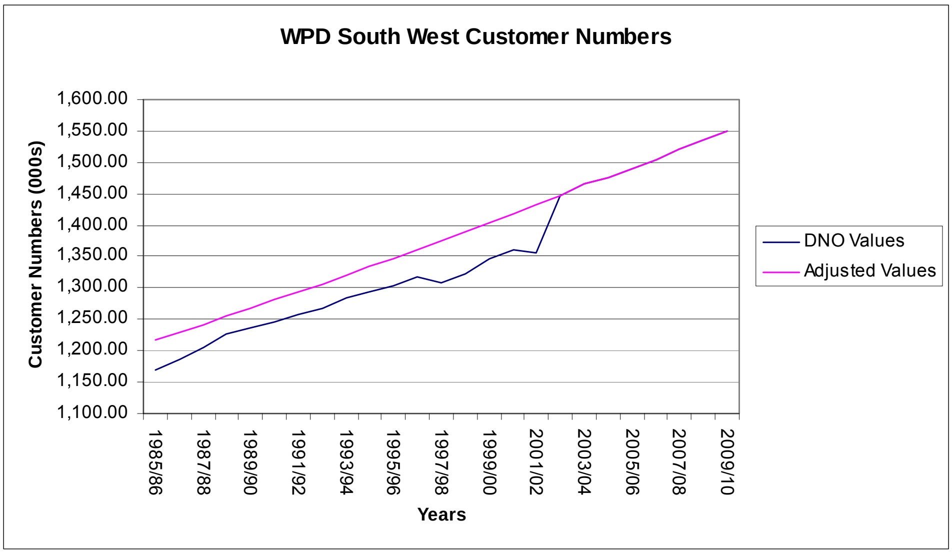
Detailed descriptions of the models are provided in Appendices D and E and the following sections discuss the validation and adjustment of the input variables and the model outputs.

3.2 Load-related expenditure

3.2.1 Model inputs

A step change in WPD South West customer numbers occurs between 2000/01 and 2002/03. To remove this step an average growth rate of 1.01% has been applied backwards from 2002/03. This average growth has been calculated between 1986/87 and 2000/01.

Table 3.1 - Adjustment of Customer Numbers



No adjustment was made to the company's forecast of HV and LV units distributed.

3.2.2 Model outputs

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

Table 3.2 - Load Related Capex Model Outputs

LRE DPCR2 (excluding generation)	**LRE DPCR3 (excluding generation)**	**Submitted LRE Gross DPCR4 (excluding generation)**	**Model Output LRE for DPCR4**
(£m)	(£m)	(£m)	(£m)
148.4	126.1	154.4	**154.4**

3.2.3 Load-related expenditure modelling comments

The model output indicates the same level of gross load-related expenditure as in WPD South West's submission.

3.3 Non-Load related expenditure

3.3.1 Model inputs

No specific model input adjustments were made for WPD South West.

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	80.3	80.5	Lines & services	82.9	89.4	82.9	
Cables	11.2	11.2	Cables & services	11.9	16.8	11.9	
Transformers	28.4	28.5	Substations	76.3	89.5	76.3	
Switchgear	37.2	37.3	Part Submission Total	171.1	195.7	171.1	
Services and Lines	3.1	3.1					
SMC	0.0	0.0					
Other Substations	10.5	10.5					
Other Not Modeled	25.3	25.3	Other Not Modeled	25.3		25.3	
Total	196.0	196.4	Total	196.4		196.4	181.2

Note: The DNO Submission total also includes £4m for tower painting.

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 (£76.6m), overhead lines (£95.3m), underground cables (£40.7m), submarine cables (£3.1) and service lines and cables (£27.5m), totalling £243.2m.)

The model's prediction of substation expenditure (switchgear, transformers) is higher than that in the DNO submission. However the "other not modelled" item is largely corporate overheads which WPD has not disaggregated by asset type. We would therefore consider the model output and the submission to be similar for substation assets.

In respect of overhead lines and services the model is predicting higher volumes and hence expenditure for the replacement of HV lines.. Furthermore the WPD South West forecast includes about £29m for remedial work on LV bare conductor lines in response to the introduction of ESQCR WPD South West would in any case have incurred some £13.7m of asset replacement expenditure in respect of LV bare conductor lines had ESQCR not been introduced. Therefore we propose that we should treat the additional amount due to ESQCR as £29.0m - £13.7m i.e. £15.3m and increase the PB Power opinion of the NLRE accordingly by £13.7m.

In respect of cables the model is predicting higher expenditure. However the "other not modelled" item is largely corporate overheads which WPD has not disaggregated by asset type. We would therefore consider the model output and the submission to be similar for cables. Moreover the corresponding difference in expenditure is not high and moreover may be influenced by the deduction of the high level of cable fault repair expenditure (£29.5m out of a total DPCR4 forecast expenditure on all cables of £40.7m). The provision for cable fault repair expenditure includes £21.1m for the replacement of LV Consac cable.

In PB Power's opinion, the allowed non-load related expenditure corresponding to the model output should be £181.2m (£163.4m as forecast plus £0.5m capitalised overhead adjustment, some £13.7m in respect of replacement of LV bare conductor lines that would otherwise have occurred had ESQCR not been introduced and £3.6m health and safety related). These amounts exclude (balance of) ESQCR expenditure, diversions, metering and fault capital expenditure. Furthermore (balance of) ESQCR expenditure has been excluded from the overall total as this matter is being considered separately.

Subject to the above observations, the above considerations would indicate that the WPD South West's submission is reasonable.

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	**126.1**	**154.4**	**154.3**	**154.4**
Non Load Related	**224.2**	**307.7**		**292.3**
Gross Capex less Non Op Capex	**350.3**	**462.1**		**446.7**
Non Op Capex (Not Assessed)	43.6	**43.7**		43.7
Total Gross Capex	**393.9**	**505.8**		**490.4**
Contributions	-63.6	-79.7		-79.7
Net Load Related	**62.5**	**74.7**		**74.7**
Total Net Capex	**330.3**	**426.1**		**410.7**
Non Load Related Summary				
Replacement		177.6		
ESQCR		15.5		
Heath & Safety		3.6		
Environment		-		
Sub Total - Model Comparison	**151.1**	**196.5**	**196.4**	**181.2**
Diversions	7.7	13.5		13.5
SCADA	0.1	-		0.0
Sub Total	***158.9***	***210.1***		***194.7***
Metering (Not Assessed)	20.3	18.3		18.3
Sub Total	**179.2**	***228.4***		**213.0**
Fault Capex (Not Assessed)	45.0	79.3		79.3
Non Load Related Total	**224.2**	**307.7**		**292.3**

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. A further £13.7m has been added to the Non-load related expenditure total in respect of LV bare conductor line.

APPENDIX A

BASE CASE SUBMISSION

APPENDIX A – BASE CASE SUBMISSION

A.1 Actual and forecast capital expenditure projection for DPCR3

In the table below we present the actual and forecast capital expenditure projection for DPCR3. The net load-related expenditure for the period is £71.4m and overall gross capital expenditure £437.7m.

Table A.1 -Actual and Forecast Capital Expenditure Projection for DPCR3 (£m at 2003/2003 prices)

	Actual			Forecast		Total
	2000/01	2001/02	2002/03	2003/04	2004/05	
Capital Expenditure						
Load Related	27.6	28.0	28.8	32.6	32.8	149.8
Capital Contributions	(14.5)	(14.4)	(14.4)	(18.3)	(16.8)	(78.4)
Non Load Related	41.9	44.4	50.9	53.0	54.1	244.3
Non-operational capex	11.8	7.2	7.6	8.0	9.0	43.6
Total Capital Expenditure	66.8	65.2	72.9	75.3	79.1	359.3

A.2 Base Case capital expenditure forecast for DPCR4

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

Table A.2 -Base Case Capital Expenditure Forecast for DPCR4 (£m at 2003/2003 prices)

	Forecast					Total
	2005/06	2006/07	2007/08	2008/09	2009/10	
Capital Expenditure						
Load Related	35.4	32.0	27.3	28.5	30.8	154
Capital Contributions	(17.4)	(16.1)	(14.7)	(15.4)	(15.9)	(79.5)
Non Load Related	56.9	58.5	61.4	62.9	63.4	303.1
Non-operational capex	9.2	7.7	9.1	8.8	8.9	43.7
Total Capital Expenditure	84.1	82.1	83.1	84.8	87.2	421.3

A.3 Forecast of load-related capital expenditure for DPCR4

WPD South West's forecast of load-related capital expenditure for the Base Case Scenario is as set out in the following table:

Table A.3 - Load-related expenditure forecast for DPCR4 (£m at 2003/2003 prices)

	2005/06	2006/07	2007/08	2008/09	2009/10	Total
New connections	22.6	20.7	18.8	19.8	20.5	102.4
Reinforcement	9.8	8.5	6.1	6.2	7.7	38.3
Generation	0	0	0	0	0	0
Other – Corporate overheads	3.0	2.8	2.4	2.5	2.6	13.3
LRE Total - Gross	35.4	32.0	27.3	28.5	30.8	154
Customer Contributions	(17.4)	(16.1)	(14.7)	(15.4)	(15.9)	(79.5)
Load-related expenditure - net	18.0	15.9	12.6	13.1	14.9	74.5

WPD has not allocated its corporate overheads between the various categories of load-related or non-load related expenditure.

A.4 New connections forecast expenditure

Connections expenditure is based on forecasts of new domestic customers derived from new housing starts whereas the forecast of small non-domestic customers derived from the historic trend with regional GDP growth. Other large connections are separately forecast based on developers' information. WPD comments that the historical correlation is not high and is dependent on MPRS data for connections. Following the separation of distribution and supply businesses, data on customer and units distributed based on the historical sector definitions of domestic, agricultural, commercial and industrial are no longer available.

WPD South West is forecasting an annual increase in customer numbers of about 15,000 per annum representing an annual increase of about one per cent in both LV and HV connected customers, the very few EHV customer numbers being static. The number of new housing starts is expected to be slightly in excess of 8,000 per year based on a forecast from a prominent econometric consultant.

The forecast level of new connections expenditure is slightly lower than that for DPCR3. WPD South West has also stated that the level of third party connections is not significant in its service area.

WPD South West has commented that forecast contribution levels (about 70 per cent of the new connections expenditure) assume the elimination of a Tariff Support Allowance and the removal of an operation and maintenance connection charge element. The company also assumes that the "25%" rule would remain unchanged in the Base Case scenario.

A.5 Network reinforcement

Reinforcement expenditure is planned to meet a seven-year demand forecast based on regional GDP growth. An average annual growth rate of 1.67 per cent in units distributed is forecast for DPCR4. The company states that a typical relationship load and regional GDP is that every 1 per cent increase in GDP tends to result in a 0.7 per cent increase in units distributed. Over the DPCR4 period the forecast increase in GDP in WPD South West service area varies between about 2 and 3 per cent annually. We have reviewed WPD South West's forecast of units distributed using historic trends and published GVA data and would consider the forecast to be reasonable. From the consideration of units distributed an overall system demand forecast is derived, the system load factor being forecast as static at about 58 per cent.

Table A.4 - WPD South West's Simultaneous Maximum Demand Forecast

	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
SMD (MW)	2967	3012	3071	3122	3173	3222	3276	3330

The overall load forecast is disaggregated down to the 33/11kV busbar level. WPD South West comments that the overall load forecast is detailed at all busbars down to those at 33/11kV substation level taking into account known areas of new business growth/closures and the effects of any proposed changes to the distribution network such as the transfer of load between substations. This process of block load allocation tends to dominate the short-term forecast.

Network planning is undertaken to meet licence requirements.

Overall the DPCR4 forecast expenditure (gross and net of capital contributions) represents a slight increase on the corresponding actual and forecast level for DPCR3, new connections expenditure being lower and reinforcement expenditure higher reflecting that the 132kV and EHV expenditures forecast for 2005/06 and 2006/07 are higher than the general trend for this expenditure. This increase is partly due to the deferment of a 132kV reinforcement scheme in mid Devon, where there have been delays in obtaining planning consents.

Other 132kV and 33kV schemes are identified. HV and LV reinforcement expenditure is estimated from trend analysis.

We would consider the basis of the forecast of load-related expenditure to be reasonable.

A.6 Non-Load related expenditure

A.6.1 General

WPD South West's forecast of non-load related expenditure is presented in the table below.

Table A.5 -Non-load related expenditure forecast for DPCR4
(£m at 2003/2003 prices)

	2005/06	2006/07	2007/08	2008/09	2009/10	Total
Non Fault Replacement	30.2	31.4	33.1	33.9	34.8	**163.4**
Metering	3.5	3.4	3.9	4.1	3.4	**18.3**
Faults	15.3	15.4	15.9	16.2	16.5	**79.3**
Diversions	2.7	2.7	2.7	2.7	2.7	**13.5**
Health and Safety	6.0	6.4	6.6	6.8	6.8	**32.6**
Environmental	0.0	0.0	0.0	0.0	0.0	**-**
Total	**57.7**	**59.3**	**62.2**	**63.7**	**64.2**	**307.1**

WPD South West is forecasting expenditure on asset replacement (non fault replacement, faults and health and safety) in DPCR4 to be £271.3m, an increase of about £70m on the actual and forecast expenditure for DPCR3. Some efficiency savings in respect of design, productivity and procurement savings are claimed, offset by increased charges due to pensions (SSAP24).

WPD South West forecasts replacement of assets in the medium to long term using age-related modelling by consideration of replacement profiles, with the aim of maintaining asset reliability and condition. A replacement factor, of unity or less, is applied to take account of assets being decommissioned for reasons other than asset replacement.

A breakdown of non-fault asset replacement expenditure, including meters, is presented below.

Table A.6 - Non-fault asset replacement expenditure for DPCR4
(£m at 2003/2003 prices)

Expenditure Classes	2005/06	2006/07	2007/08	2008/09	2009/10	Total
Substations	13.9	14.6	15.4	15.8	16.4	**76.1**
Overhead lines	10.5	10.2	10.2	9.9	9.8	**50.6**
Underground cables	1.2	1.7	2.2	2.9	3.2	**11.2**
Submarine cables	-	-	-	-	-	**-**
Service lines and cables	0.4	0.6	0.6	0.7	0.8	**3.1**
Meters	3.5	3.4	3.9	4.1	3.4	**18.3**
Tele-control / SCADA	0	0	0	0	0	**0**
Easement expenditure	1.3	1.3	1.3	1.3	1.3	**6.5**
Lane rentals	0	0	0	0	0	**0**
Other operational capital expenditure – Corporate overheads	2.9	3.0	3.4	3.3	3.3	**15.9**
Total Non Operational	0	0	0	0	0	**0**
Total	**33.7**	**34.8**	**37.0**	**38.0**	**38.2**	**181.7**

Refurbishment of overhead lines, particularly replacement of wood poles, is to remedy without delay such defects that are found by routine inspection. WPD South West inspects HV overhead lines every two years by helicopter and every ten years on foot. The company's policy is to remedy any defects so identified without delay. WPD South West has presented charts showing the 20-year long-term trends in asset replacement expenditure and evolution of average ages of the principal asset categories (slight decreases in average asset ages for switchgear, transformers, overhead lines, but a slowly increasing trend for underground cables – all voltages). WPD's asset management process is supported by the company's comprehensive asset management database, CROWN.

Table A.7 - WPD South West's forecast trends of asset replacement
(All voltages)

Asset	Expenditure as % of MEA			Average Age (Years)		
	2005/06	2009/10	2024/25	2005/06	2009/10	2024/25
Switchgear	1.5	1.8	1.9	29	30	28
Transformers	1.4	1.7	2.1	32	33	28
Overhead lines	2.4	2.4	1.6	39	38	35
Underground cables	0.5	0.8	1.3	35	37	43

The proportions of replacement to refurbishment for overhead lines forecast for DPCR4 are as stated below.

Table A.8 - Overhead line replacement and refurbishment

Voltage	OHL Replacement (%)	OHL Refurbishment (%)
LV	40	60
HV	0	100
EHV	20	80
132kV	70	30

We comment below on a number of specific asset categories.

A.6.2 HV overhead line refurbishment

WPD South West has forecast expenditure of £33.8m for the refurbishment of some 2562km of HV overhead line under the Base Case. This level of refurbishment corresponds to about 3.0 per cent of that category of line length per year and is estimated to be the amount required to maintain the number of unplanned incidents at the present level. The activity level was derived from age-based modelling.

A.6.3 ESQCR and LV bare conductor lines

The principal reasons for the forecast increase in asset replacement are an increase in asset replacement activity level in all asset categories, reflecting average asset ages, as well as legislative changes. In the latter case (and classified under "health and safety") WPD South West has forecast capital expenditure of about £30m to undertake remedial work on some 1277km of LV bare conductor line where clearances to buildings are only about 6 feet. WPD has cited compliance with ESQCR 2002 and EATS 43-8, Issue 2 December 1988, Overhead Line Clearances, as being the principal drivers.

EATS 43-8 specifies a minimum clearance of 3 metres at this voltage. WPD South West has submitted to DTI a procedure for assessing the risk of LV open wire overhead lines near buildings. The £30m estimate is however based on a survey of only about 10 per cent of the LV network. Under ESQCR all DNOs are required by January 2008 to have compiled a list of outstanding lines and to have reviewed their plans to undertake remedial work.

A.6.4 LV Consac cable

WPD South West has made provision of £21.1m for the replacement of some 400km of LV Consac cable which is exhibiting unreliability due to problems with service joints. Replacement may be reactive, in response to faults, or pro-active if a number of faults are observed on a given cable. WPD South West was not among the DNOs for which Ofgem made a special allowance in DPCR3 for replacement of LV Consac cable.

A.6.5 Diversions

WPD South West is forecasting £13.5m in non-rechargeable diversions expenditure, in line with recent trends.

A.6.6 Meters

WPD South West is forecasting a decrease of £3.4m in meter expenditure, being a function of the evolution of the average age of the metering base.

A.6.7 Conclusions

Subject to ongoing discussions between Ofgem and DTI in respect of compliance with ESQCR, we would consider the basis of the forecast of non-load related expenditure to be reasonable. We would however consider that the provision of £29m for the remedial work on LV bare conductor overhead lines should be subject to review as there is uncertainty over the extent of WPD's liability (survey work is continuing) and the timing of such remedial work which, even if it proceeds, may not all be completed in DPCR3.

APPENDIX B

OFGEM SCENARIO/SENSITIVITY ANALYSIS

APPENDIX B – OFGEM SCENARIO/SENSITIVITY ANALYSIS

B.1 Network performance improvements

WPD South West's response to the Ofgem Scenario/Sensitivity Analysis is presented below.

FPPQ	Central Improvement Scenario	Value
Ofgem Annex 1 to FBPQ 4719_Forecast_BPQ_annex_Oct03.pdf	Unplanned CIs - Ofgem 2010 assumption	84.9
	Unplanned CIs - Ofgem 2020 assumption	80.0
	Unplanned CMLs - Ofgem 2010 assumption Unplanned CMLs - Ofgem 2020 assumption	65.9 65.9
WPD FBPQ narrative	Unplanned CIs – 2004/5 Mid Point Forecast Out-turn	85.7
	Unplanned CMLs – 2004/5 Mid Point Forecast Out-turn	60.7
Table 39	Unplanned CIs - DNO 2005 forecast Unplanned CIs - DNO 2010 forecast Unplanned CIs - DNO 2020 forecast	85.6 84.9 80.0
	Unplanned CMLs - DNO 2005 forecast Unplanned CMLs - DNO 2010 forecast Unplanned CMLs - DNO 2020 forecast	60.7 60.7 60.7
Table 40.1	Capital expenditure (2004 to 2005 inclusive) (£m) Capital expenditure (2006 to 2010 inclusive) (£m) Capital expenditure (2011 to 2015 inclusive) (£m) Capital expenditure (2016 to 2020 inclusive) (£m)	0 15.3 43.4 48.2
Table 15	Customer numbers (2010)	1,550,606
Calculated value	Capex per customer hour lost (£/CHL) – DPCR4	Infinite

WPD South West has commented that the existing underlying customer minutes lost (CML) performance is better than Ofgem's 2019/2020 assumption and that therefore the requirement is to maintain the existing underlying performance.

During DPCR3 WPD South West is underspending on quality of supply, commenting that there is very limited scope for low cost solutions targeted in improving quality of supply. For the (DPCR4) quality of supply scenario WPD South West has identified only one main work stream, namely refurbishment of HV overhead lines, to improve the customer interruption (CI) performance. WPD South West would refurbish a further 1150km of HV overhead line at a cost of £15.3m (in addition to the Base Case proposal to refurbish 2562km at a cost of £33.8m). However the additional refurbishment would produce negligible changes in CIs and CMLs, improvements in unplanned incidents being offset by a deterioration in planned incidents, both movements being slight. WPD South West points out that it expects that there would be a marginal benefit in terms of multiple interruption performance and that a refurbished HV overhead line would be more resilient to severe weather. Neither improvement is quantified however.

We would however regard the cost (in terms of undiscounted capital expenditure) as being high relative to the benefit obtained, noting that only one generic improvement measure has been considered.

Scenario 2 – Higher target for customer interruptions

Scenario 3 – Lower target for customer interruptions

WPD South West's response to the CI sensitivity scenario is presented below.

FPPQ	2% DETERIORATION IN CI PERFORMANCE	Value
Table 41.1 of FBPQ QoS response	Capital expenditure (2004 to 2005 inclusive) (£m)	0
	Capital expenditure (2006 to 2010 inclusive) (£m)	0
	2% IMPROVEMENT IN CI PERFORMANCE	
Table 41.2 of FBPQ QoS response	Capital expenditure (2005 to 2005 inclusive) (£m)	0
	Capital expenditure (2006 to 2010 inclusive) (£m)	41.5
Calculated value	Capex per customer hour lost (£/CHL) – DPCR4	892

WPD South West has pointed out that the deterioration case (Scenario 2) is not viable (in terms of the FPBQ instructions) as this would have represented a worsening of the existing performance level.

The lower target for 2009/10 would be 83.3 unplanned customer interruptions per 100 connected customers (central scenario minus 2 per cent) and the consequent resulting interruption duration performance would be 58.9 customer minutes lost. Again only one work stream, refurbishment of a further 3135km of HV overhead line at an aggregate capital cost of £41.5 million, is proposed. The specific cost (in terms of undiscounted capital expenditure) would be about £900 per customer hour saved and which we would regard as high, assuming no other benefits such as resilience improvement were attributed. At this level of expenditure we would consider that WPD South West would inevitably find a lower cost means of achieving the indicated level of performance.

Scenario 4 –Higher target for customer minutes lost

Scenario 5 – Lower target for customer minutes lost

WPD South West's response to the CML sensitivity scenario is presented below.

FPPQ	5% DETERIORATION IN CML PERFORMANCE	Value
Table 41.3 of FBPQ QoS response	Capital expenditure (2004 to 2005 inclusive) (£m)	0
	Capital expenditure (2006 to 2010 inclusive) (£m)	0
	5% IMPROVEMENT IN CML PERFORMANCE	
Table 41.4 of FBPQ QoS response	Capital expenditure (2005 to 2005 inclusive) (£m)	0
	Capital expenditure (2006 to 2010 inclusive) (£m)	64.5
Calculated value	Capex per customer hour lost (£/CHL) – DPCR4	832

WPD South West has pointed out that the deterioration case (Scenario 4) is not viable (in terms of the FPBQ instructions) as this would have represented a worsening of the existing performance level.

The lower target for 2009/10 would be 57.7 unplanned customer minutes lost (central scenario minus 5 per cent) and the consequent resulting interruption performance would be 81.7 customer interruptions per 100 connected customers. Again only one work stream, refurbishment of a further 4875km of HV overhead line at an aggregate capital cost of £64.5million, is proposed. The specific cost (in terms of undiscounted capital expenditure) would be about £800 per customer hour saved and which we would regard as high, assuming no other benefits such as resilience improvement were counted. At this level of expenditure we would consider that WPD South West would inevitably find a lower cost means of achieving the indicated level of performance.

B.2 Resilience undergrounding

In order to underground 2% of its overhead network WPD South West would need to underground some 625km of LV line and 171 of HV line at a cost of approximately £58.5m. No improvement in CIs or CMLs has been claimed although WPD South West acknowledges that the undergrounding would result in a marginal improvement in resilience.

B.3 Amenity undergrounding

To underground all overhead lines within National Parks and Areas of Outstanding Natural Beauty, WPD South West estimates that some 9068km of overhead lines at all voltage levels would have to be undergrounded at a cost of £1009.7m which would represent about 22 per cent of the network's replacement cost (or modern equivalent asset value – MEAV).

B.4 Accelerated overhead line up rating

WPD South West's Base Case scenario caters for 2562km of HV overhead line refurbishment at an aggregate capital cost of £33.8m. To meet the accelerated overhead line up-rating target (to EATS 43-40) WPD South West proposes to refurbish additional 280km at a cost of £3.5m, all HV overhead lines being in accordance with EATS 43-40 by 2034/35. No corresponding improvement in CI or CML performance is claimed however.

B.5 Conclusions

WPD South West's responses to the quality of supply scenario and its sensitivity cases (which in some cases would represent a deterioration of performance from existing levels) would indicate high costs for such improvement that might be gained when considered in headline terms of cost per customer hour saved. Despite the company's statement to the effect that lower cost measures (such as automation) are largely exhausted, at this level of expenditure we would consider that WPD South West would inevitably find a lower cost means of achieving the indicated level of performance.

Both this and the other scenarios however raise the question of how other benefits such as resilience and improvements to multiple interruption performance might be evaluated.

APPENDIX C

DNO ALTERNATIVE SCENARIO

APPENDIX C – DNO ALTERNATIVE SCENARIO

C.1 Introduction

The difference between the capital expenditure forecast in the Base Case Scenario and the DNO Alternative Scenario is set out below and totals £66.4m.

Programme - £m	2005/06	2005/07	2007/08	2008/09	2009/10	Total
Quality of supply improvement				6.2	9.1	15.3
Development of distributed generation	2.4	2.8	3.1	3.6	4.4	16.3
- capital contributions	-1.2	-1.4	-1.6	-1.8	-2.2	-8.2
Network resilience						
Changes to legislation						
Imposition of lane rental charges - new connections	4.8	4.8	4.8	4.8	4.8	24.0
- capital contributions	-3.4	-3.4	-3.4	-3.4	-3.4	-17.0
- cable replacement/repairs	7.2	7.2	7.2	7.2	7.2	36.0
Impact of structure of charges work on EHV charges						
Total	9.8	10.0	10.1	16.6	19.9	66.4

C.2 Quality of supply

WPD South West proposes to undertake an additional 1150km of overhead line strengthening (£15.3m) over the Base Case to further reduce the number of unplanned incidents. This measure is the same as in the “Ofgem Central Quality of Supply Scenario” but would be confined to the years 2008/09 and 2009/10 only instead of being spread over each of the years in DPCR4.

FPPQ	DNO SCENARIO	Value
Forecast scenario proposed by WPD South West	Unplanned CIs – 2004/5 Mid Point Forecast Out-turn	85.6
	Unplanned CMLs – 2004/5 Mid Point Forecast Out-turn	60.7
Table 39 (preferred case)	Unplanned CIs - DNO 2005 forecast Unplanned CIs - DNO 2010 forecast Unplanned CIs - DNO 2020 forecast	85.6 84.9 80.0
	Unplanned CMLs - DNO 2005 forecast Unplanned CMLs - DNO 2010 forecast Unplanned CMLs - DNO 2020 forecast	60.7 60.2 56.7
Table 40.1	Capital expenditure (2004 to 2005 inclusive) (£m) Capital expenditure (2006 to 2010 inclusive) (£m) Capital expenditure (2011 to 2015 inclusive) (£m) Capital expenditure (2016 to 2020 inclusive) (£m)	0 15.3 43.4 48.2
Table 15	Customer numbers (2010)	1,550,606
Calculated value	Capex per customer hour lost (£/CHL) – DPCR4	1184

In its alternative scenario WPD South West has also projected a different timing for the introduction of customer interruption performance improvements which would commence in 2008/09 instead of 2006/07. Furthermore in the alternative scenario a small reduction in customer minutes lost is claimed whereas in the response to the Ofgem Central Quality of Supply Scenario, the underlying existing performance is maintained and no CML improvement is claimed. As the proposed measure (strengthening of 1150km of overhead lines) is the same we would regard the differences in CML forecasts as being semantic.

As commented earlier, despite the company's statement to the effect that lower cost measures (such as automation) are largely exhausted, at this level of expenditure we would consider that WPD South West would inevitably find a lower cost means of achieving the indicated level of performance.

Both this and the other scenarios however raise the question of how other benefits such as resilience and improvements to multiple interruption performance might be evaluated.

C.3 Distributed generation

WPD South West has proposed additional expenditure for the connection of distributed generation, comprising some £16.3m offset by £8.2m capital contributions, a net increase of £8.1m.

The company has based its assumptions on the "SCAR" report to the DTI[1] and has expressed the view that a mixed technology scenario is likely to be seen going into DPR4 but that only 60 per cent of the generation required to meet the Renewable Obligation would be connected by 2010. The table below indicates the cumulative distributed generation capacity on which capital costs have been calculated using mid-point costs on a £/MW basis. The company has also commented that sole use assets are those are those up to the point of common coupling at the time of connection and have been taken as fully recoverable through a connection distribution charge. We would regard the average cost of about £86,000 per MW as typical although there can be a wide variation depending particularly on the length of the connection.

Forecast of Cumulative Distributed Generation Capacity (MW)

	2005/6	2006/7	2007/8	2008/9	2009/10
WPD South West	28.4	60.7	96.7	138.4	189.6

As distributed generation is the subject of the separate Distributed Generation Questionnaire, we would suggest that this particular response be reviewed further in the context of the Distributed Generation review being undertaken by Ofgem.

[1] Ilex/UMIST report to DTI; Quantifying the System Costs of Additional Renewables in 2020, October 2002

C.4 Network resilience

Following the report of the Network Resilience Working Group, WPD South West proposes to move from a 5-year to a 3-year tree cutting cycle for HV lines and to undertake tree cutting associated with LV lines on a cyclical basis. The enhanced tree cutting would result in an increase in operating costs of £1.7m per year. WPD South West draws attention to the exposure of its network to high winds and states that although this increased activity would have negligible impact on overall quality of supply during normal weather conditions, it would be of benefit during severe weather.

We would comment that the proposed increase represents a virtual pro-rata increase on the Base Case forecast of £3.1m per year (Table 20). However we would expect that the present 5-year cycle tree cutting activity would include for re-visits and that there would be a trade-off between heavier cutting at 5 years and lighter cutting (less growth) at 3 years. Hence we would consider that an increase of £1m per year would be more appropriate.

C.5 Changes to legislation

WPD South West identifies possible changes in or changes in the interpretation of existing legislation that could increase costs of compliance. The company suggests that any changes to legislation should be the subject of a “regulatory impact assessment” before implementation. Other than the capital expenditure to undertake remedial work on LV bare conductor overhead lines already included in the Base Case, WPD South West has not quantified any liability for changes to legislation and so we have not considered the issue further.

C.6 Lane rental charges

WPD South West estimates that impending changes to legislation whereby charges would be imposed on utilities when excavation works are carried out on the public highway, namely lane rental charges, would incur charges of £12.0m per year. The estimate considers the number of excavation works per year, mix of routes and planned or emergency works and likely level of charges for highway occupancy. The estimated costs have been allocated as an annual charge of

- £4.8m to new connections, offset by an increase of £3.4m in connection charges (DPCR4 net increase £7m) and
- £7.2m to cable replacement/repairs (DPCR4 increase £36m).

We would regard this level of charges as high compared with those indicated by other DNOs. The £7.2 million of cable replacement/repairs is moreover equal to the combined faults and non-faults non-load related cable expenditure in the Base Case for the year 2005/06. As the level of charges for highway occupancy is uncertain, we would suggest that this matter be reviewed separately by Ofgem as part of a global review of lane rentals as applied to operating and capital expenditures.

C.7 EHV charges

The WPD South West forecast assumes that the existing method of setting EHV charges continues to apply, noting that there are possible moves to harmonise the structure of these charges between DNOs (Ofgem Structure of Charges initial decision document, November 2003).

WPD South West has not quantified its exposure to any likely changes to charging structures. As we note that this matter is under discussion within the Electricity Distribution Charges Implementation Steering Group, we have not considered it further.

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.

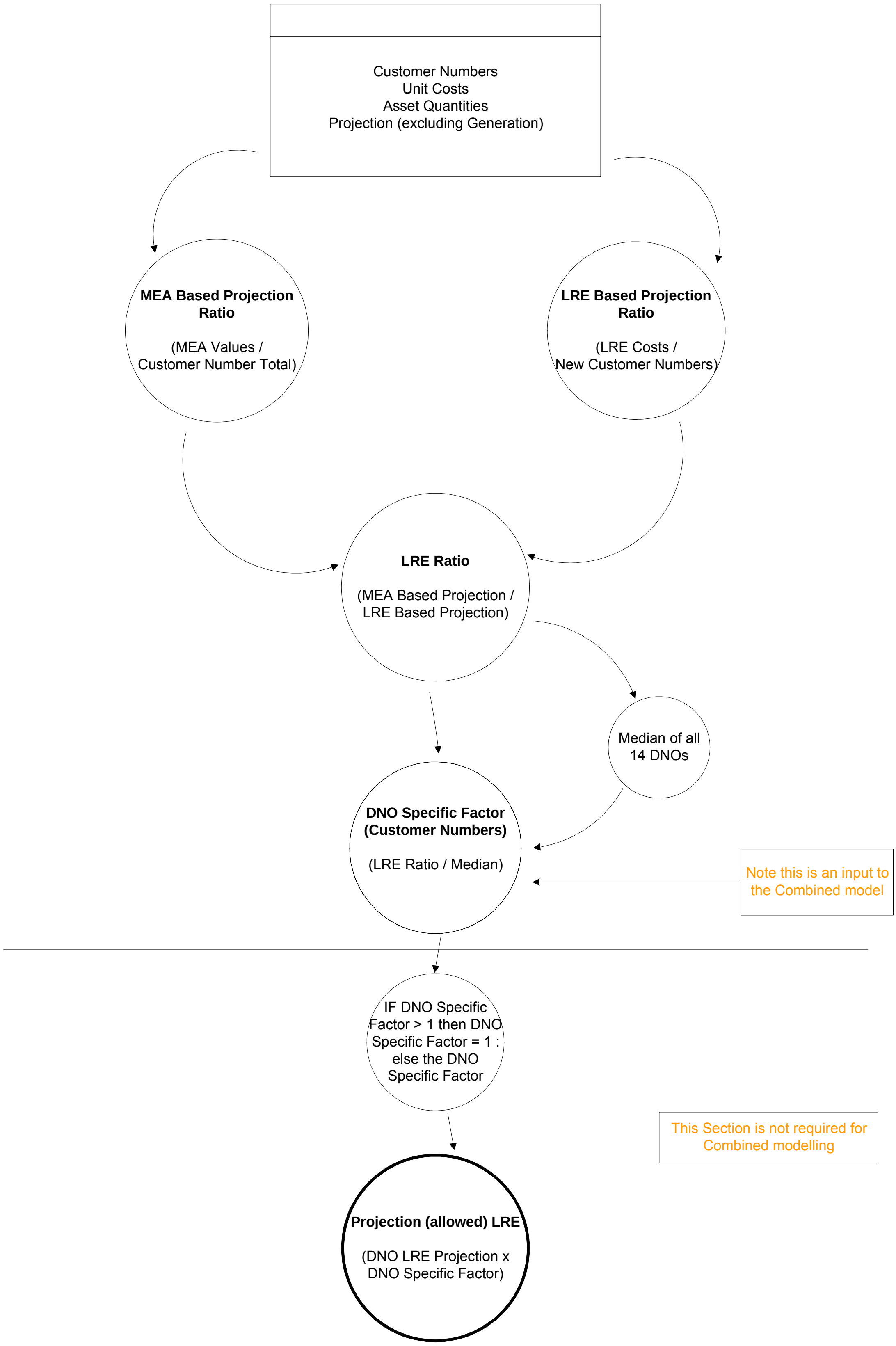
Being benchmarked on a median rather than on an average implies that extremes do not affect the adopted benchmarking position. It also means that the LRE of each company is compared relative to its cost base against the Industry Trend and not in absolute cost terms. This approach recognises therefore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

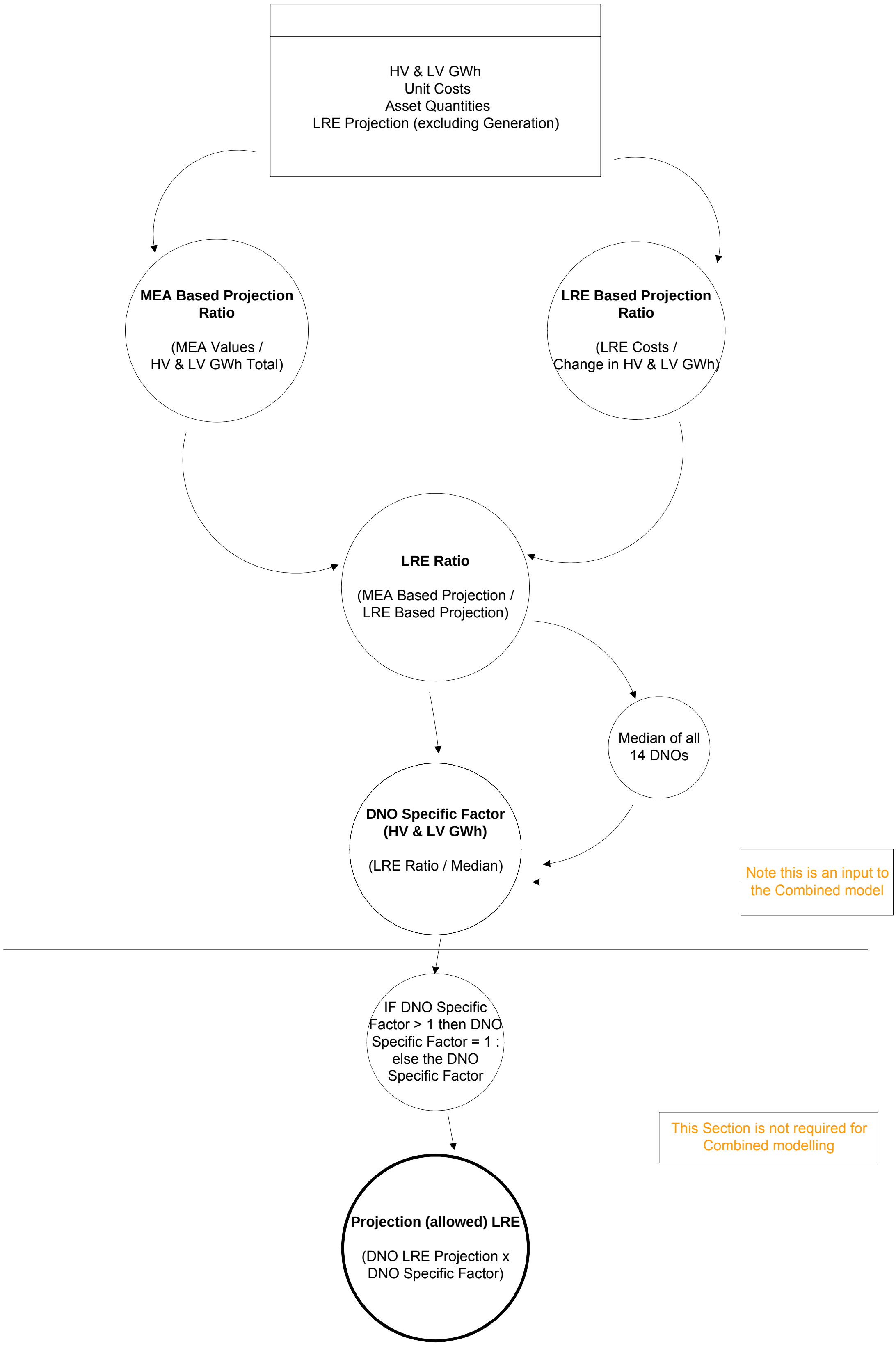
Although each DNO's network is comprised of a large number of smaller networks and that it would be expected that these would have a range of spare capacities depending on local load growth and when individual networks were last reinforced, it is possible that a larger number of the smaller networks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

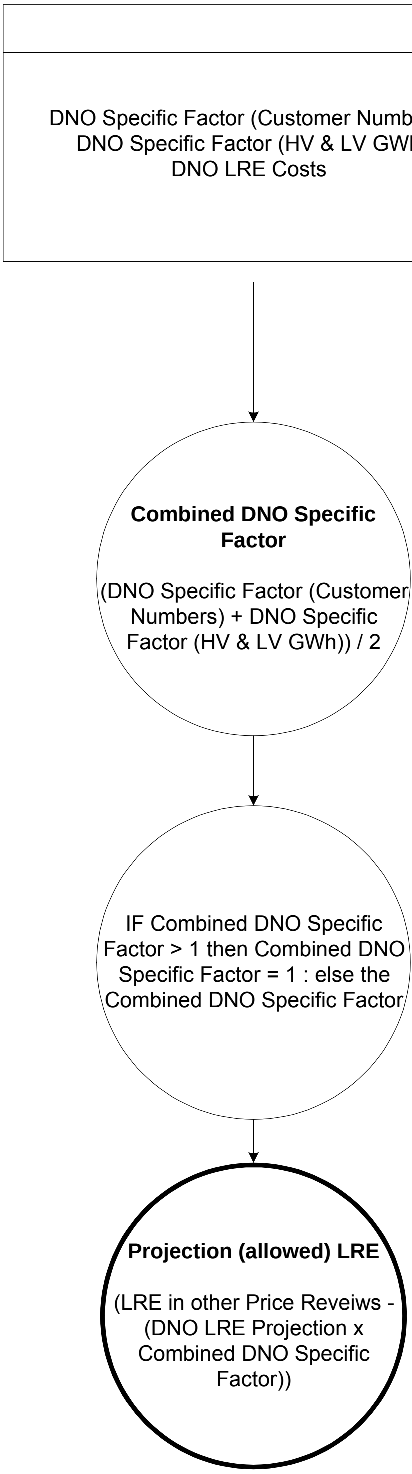
Combined Load Related Expenditure Modelling (Phase 1A Customer Numbers)



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)

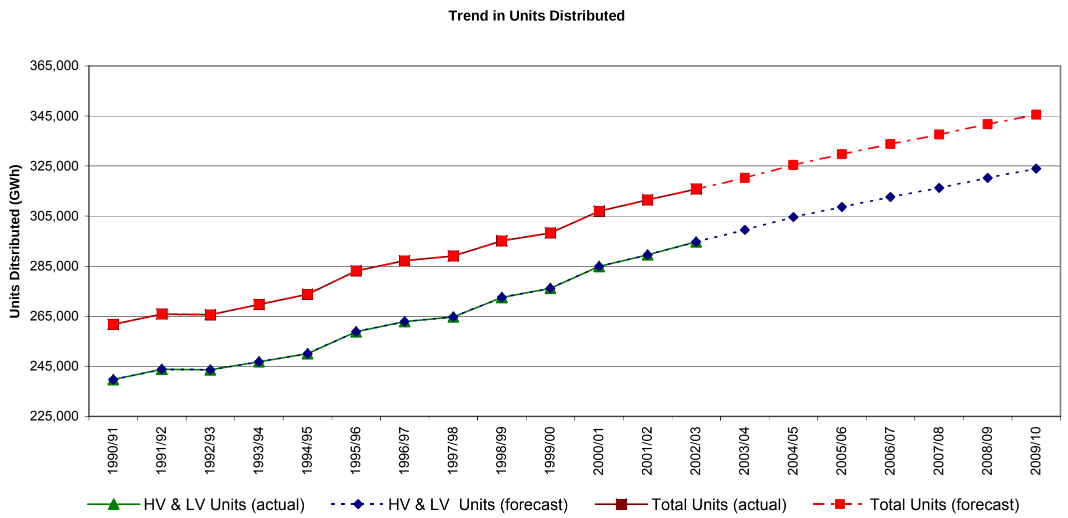
For the purposes of this review, GVA is treated as being synonymous with gross domestic product (GDP). Furthermore Regional Accounts are currently published in terms of GVA[1] only. Statistics are published by geographical region in accordance with the Nomenclature of Units for Territorial Statistics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

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

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

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

Trend of energy distributed against time.



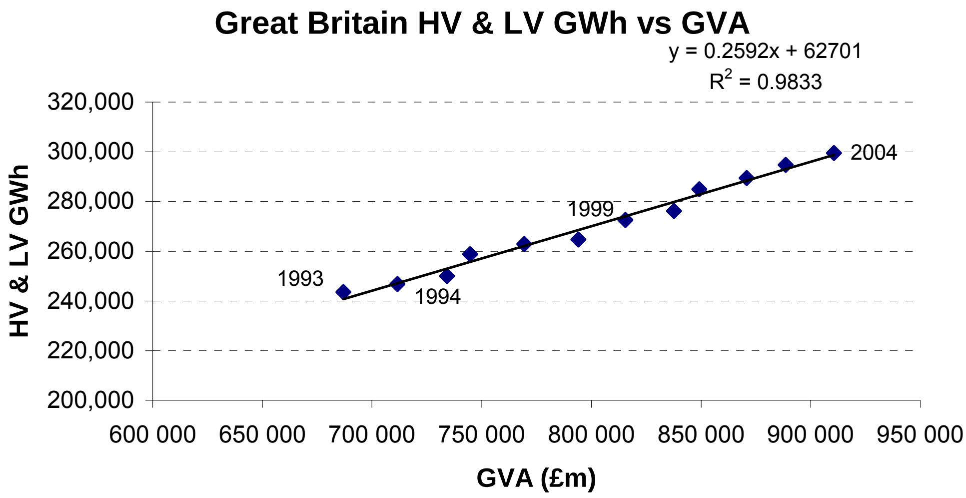
The total regulated units are HV and LV units and the total regulated units include EHV units. Up to and including 2003/03, the units distributed are actual units whereas from 2003/04 onwards these are forecast.

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.

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

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:

i. age profile

ii. retirement profile and

iii. unit cost.

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

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

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

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

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

F.1.1.2 Cyclic refurbishment / replacement

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

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

F.1.1.3 Assumptions

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

F.1.1.3.1 Overhead lines

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

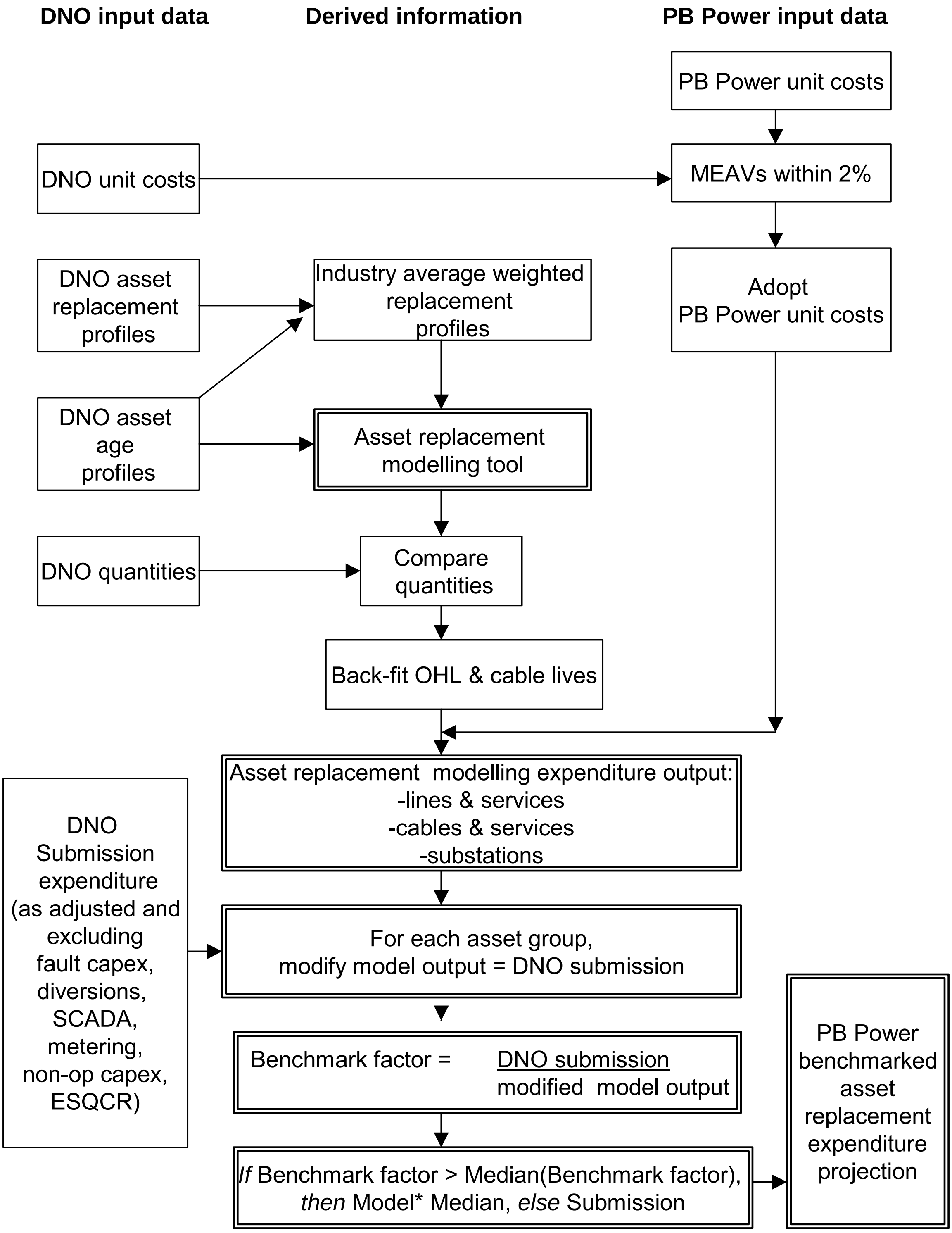
The model output is initially modified so that for each of the asset groups the overall industry (14 DNOs') expenditure predicted by the model is the same as that forecast by the DNOs. (The differences had in any case been small.) For each asset group, benchmark factors of DNO submission/model output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