OFGEM

EDF (EPN)

DPCR4 – FBPQ ANALYSIS AND CAPEX PROJECTIONS

DECEMBER 2004

LIST OF REVISIONS

Current Rev.	Date	Page affected	Prepared by	Checked by (technical)	Checked by (quality assurance)	Approved By
Final	8/12/04	All	TR Poots	J A K Douglas	G Evans	G Evans
1st Draft	2/04/04	All	REVISION HISTORY First issued as Document No. 61877/PBP/000480 PE001343_PE_EDF (EPN) Final v1.doc			
Final	29/06/04	All	Adjustment following submission of final capital expenditure numbers.			
Final	31/10/04	All	Revision of model and allowance levels following DNO meetings with Ofgem and Ofgem September paper.			
Final	24/11/04	All	Revision of text referring to transfer of expenditure from Base Case to DNO Alternative Case, references to lead sheathed fluid filled cable replacement, quality of supply submissions and status of medium and high risk scenarios.			
Final	8/12/04	All	Revisions to text following receipt of EDF's comments dated 29 November 2004.			

CONTENTS

Page No.

APPENDICES:

LIST OF ABBREVIATIONS

ACS	Average Cold Spell
capex	Capital expenditure
CHL	Customer hours lost
CI	Customer interruptions per 100 customers
CML	Customer minutes lost per connected customer
Consac	A type of concentric LV mains cable
DNO	Distribution Network Operator
DPCR	Distribution Price Control Review
DTI	Department of Trade and Industry
EATS	Electricity Association Technical Specification
EPN	EDF(EPN)
EHV	Extra High Voltage (i.e. > 22kV)
ESQCR	Electricity Safety, Quality and Continuity Regulations 2002
FBPQ	Forecast Business Plan Questionnaire
GDP	Gross Domestic Product
GVA	Gross Value Added
GWh	Gigawatthour (a unit of energy)
HBPQ	Historic Business Plan Questionnaire
HV	High Voltage (i.e. between 1kV and 22kV)
km	kilometre
kV	kilovolt
LV	Low voltage (i.e. less than 1kV and here 230/400V)
m	Million
MEAV	Modern Equivalent Asset Value
MPAN	Meter point Administration Number
MPRS	Meter Point Registration System
MW	Megawatt (a unit of power)
NAMP	Network Asset Management Plan
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

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 as well as adjustments to the DPCR3 Projection and corrections to the DPCR4 forecast submitted by EDF at the end of October 2004.

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

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

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

In forming a "PB Power" opinion of the proposed allowance, we have observed the approach set out above. Our modelling has been used as a guide and, where expenditure differing from that indicated by the model has been justified and is in keeping with Base Case Scenario, we have duly taken account of such differences.

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

EXECUTIVE SUMMARY

The following table summarises the EDF(EPN)'s adjusted DPCR3 projection, adjusted DPCR4 forecast, PB Power's modelling results and opinion of proposed expenditure.

Expenditure Category	**Adjusted DPCR3 Projection (£m)**	**Adjusted DPCR4 Forecast (£m)**	**Model Output (£m)**	**PB Power Opinion (£m)**	**PB Power Comments**
Load Related Expenditure - Gross	387.5	556.5	446.2	446.2	The model was run with the DNO proposed DPCR4 LRE uplifted for competition in connections.
Customer Contributions	(242.3)	(245.1)		(245.1)	
LRE Net	**145.2**	**311.4**		201.1	
Asset Replacement	257.5	379.2	363.5	363.5	We consider that EDF (EPN)'s forecast for lines is acceptable but the model has projected lower expenditures for cables and substations.
Other	169.8	212.8		198.5	£198.5m comprises £36.1m diversions, £8.0m SCADA, £59.7m metering and £94.7m fault capex.
NLRE Total	**427.3**	**592.0**		562.0	
Non Operational	20.0	51.0		51.0	
DNO Total	**592.6**	**954.5**		**814.1**	
DNO Total				*608.7*	*Generally as Ofgem Sep 04 paper, excl. meters, faults, non-operational and ESQCR compliance.*

Base case submission

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

Adjustments have been made to EDF(EPN)'s DPCR4 forecast in respect of overall customer connections, capitalised overheads and inter-company margin.

Our principal findings are summarised below.

Load related expenditure

1. Our initial assessment of load related expenditure tends to indicate that the gross Load Related Expenditure submission is at least £110m high and may be as much as £160m high.

2. Moreover, this opinion is supported by the review of network strategy and expenditure plans that include projects that appear quite tenuous and proposed expenditure streams that contain large provisions. As the Price Review progressed, some of the projects listed were superseded by others and portions of the contingency sums were allocated to additional or alternative projects.

Non-load related expenditure

1. The benchmarked non-load related model output for asset replacement expenditure for EDF(EPN) is approximately £16m lower than the forecast submitted. This is not unexpected since EDF have advised that, in some instances, asset replacement expenditure has been brought forward from DPCR5 in order to make work programmes more manageable in the future. EDF have subsequently confirmed that the replacement of assets within the DPCR4 period will be driven by condition/operational risk/reliability and not some concept of a 'cliff face'.

2. The modelled output has resulted in the submission value for overhead lines and services being accepted. This indicates that a combination of activity and unit price proposed by EDF is within that determined using industry data.

3. The modelled output has constrained forecast expenditure for the generic asset classes of cables and services and substation. The main contributor to a high submission value compared to a model value arises in the sub-asset class of switchgear. A higher than industry-level submission for cables also exists but to a much lesser degree. Given that the model is driven purely by DNO data then such differences represent a variance in activity level compared to industry-level practice

and unit cost. EDF consider that the variance may be due to differences in the mix and condition of asset types between DNOs.

We would also make the following general comments:

- PB Power's non-load related modelling is based on the asset lives provided by DNOs. Subsequent refinements have been made to this modelling to reflect PB Power's view of efficient DNO policies and practice.
- There is some concern about the comparability of data between DNOs due to different policies applied by DNOs, particularly the boundary between fault and non-fault replacement and capitalisation of overheads.
- The data presented in this appendix includes comparisons between DPCR3 allowances, DPCR3 projections and DPCR4 forecasts. Care needs to be taken in reviewing these figures in respect of the following:
  - The DPCR3 allowance included £2.30 per customer per year (1997/98 prices) capex for quality of supply[1], which is not separately identified in the DPCR3 projections and is not included in the Base Case DPCR4 forecast.

Quality of supply scenarios

- While details of quality of supply expenditure associated with the 2010 targets have been provided, the submission for the 2020 scenario is largely descriptive in nature without supporting analysis or justification for the particular proposals tabled and without supporting details of consideration of options and costs.

DNO alternative case

- The initial DNO Alternative Scenario and the Base Case Submissions are the same with the exception of performance improvement expenditure and the comments above on the Base Case Submission are equally applicable to the DNO Alternative Case. EDF subsequently transferred the expenditure associated with some of the performance improvement expenditure from the Base Case to the DNO Alternative Scenario.

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

PB POWER VIEW ON LOAD RELATED AND NON LOAD RELATED EXPENDITURE ALLOWANCES

Load related expenditure

Our assessment of load related expenditure tends to indicate that both gross and net Load Related Expenditure forecasts are high. This opinion is based on both the load related model output which makes due allowance for possible under expenditure during DPCR2 and DPCR3 and on the review of the submission and supporting documents.

All runs of the load related model, over different time periods and using both DNO and PB Power unit costs, show that the submission is high. The review of network strategy and expenditure plans has identified projects that appear quite tenuous and proposed expenditure streams that contain large provisions.

The net load related allowance proposed is about £200m which is approximately 40% higher than net expenditure in DPCR3 and will allow increased infrastructure expenditure in DPCR4.

Non-load related expenditure

It is significant that the non-load related model generates substantially lower substation expenditure for the EDF companies than forecast by EDF since for most other DNOs, the modelled output is higher or broadly consistent with the DNO submission. Therefore it is difficult to reconcile why the EDF companies should not be in step with the industry view for this asset class.

£363.5m has been allowed for asset replacement based on the model output for substations, cables and services together with the full programme of overhead line work submitted.

Conclusion

While the EDF(EPN) submission is considered to be high for both the load related and non-load related categories and the allowances proposed are less than the submission, nevertheless, a significant increase in net capital expenditure amounting to 40% above the DPCR3 expenditure levels is proposed.

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% and ± 5% of the 2010 targets. The targets are based on Ofgem's view depending on the nature of each of the DNO networks.

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

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

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

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

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

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

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

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

Adjustments to DPCR4 forecast

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

Such adjustments have been made after PB Power had completed a detailed review of the FPBQ submissions. Therefore certain numbers relating to capital expenditure items in the general text of the report refer to the original unadjusted numbers as presented by the DNOs. Such numbers have not been adjusted retrospectively.

However, for avoidance of doubt, all modelled outputs relying on DPCR4 submission (forecast) values have been based on the "Adjusted DPCR4 Forecast" values and not necessarily those values as originally submitted.

2. DNO SUBMISSIONS

2.1 Base case

EDF(EPN)'s approach to forecasting the Capex projections has been to define the DNO Alternative Case in the first instance and then to omit performance improvement expenditure from this to derive the Base Case. This is a different approach to the majority of the DNOs and it results in minimal difference between the DNO Alternative Case and the Base Case.

Although EDF(EPN)'s approach has been to comply with the request that the Base Case should maintain the current level of network performance/faults until 2020, the basis of the DNO Alternative Case and by its nature, the Base Case, is a broad based risk management approach and both longer term network risks and business risks have been addressed, to reduce;

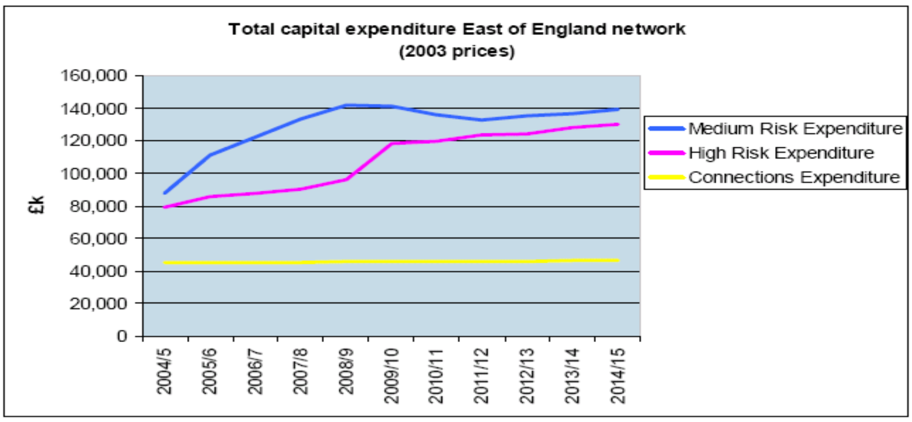
a. The current level of network risk associated with the number of substations that are currently operating above their firm capacity therefore requiring load transfers under fault conditions; and

b. The risks associated with managing asset replacement in the future assuming that this need will materialise in accordance with EDF(EPN)'s current replacement age profiling expectations.

It is implicit in EDF(EPN)'s approach that they do not consider that either the level of network reinforcement proposed, or the level of asset replacement expenditure proposed over the next 2 regulatory periods would improve the level of network performance.

While these risk management objectives have been set for both the Base Case and the DNO Alternative Case, EDF have modelled in their NAMP what they refer to as a "Medium Risk" and "High Risk" approach for each scenario. The "High Risk" and "Medium Risk" Capex Projections associated with the DNO Alternative Case are reproduced from the EDF(EPN) NAMP below. EDF have stated that the high risk plan was a method of testing whether a continuation of DPCR3 investment levels was tenable.

Chart 2.1 - Medium & High Expenditure Scenarios



The shape of the above curves reflects that the ‘ramp-up’ of expenditure proposed under the ‘medium risk’ scenario has been advanced by 4 years with respect to the ‘high risk’ scenario. Neither expenditure profile represents a minimum capex projection required for the next regulatory period since both expenditure profiles are aimed at a reduced level of network risk below the current level. EDF quantify the level of risk as the number of substations overloaded above a certain percentage of time, 5% or 10%. Both scenarios tabled by EDF are intended to reduce or eliminate the number of substations that fall into one or other of the above categories. It may be that other substations will have higher loads than at present but they cannot go into the overload situation without impacting on the numbers that EDF say they are going to reduce and on this basis, the overall level of risk, as quantified and expressed by EDF will reduce.

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

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

Item	DPCR3 Allowance	Adjusted DPCR 3 Projection	DPCR 4 Forecast	DPCR4 Corrections	Revised DPCR4 Forecast
Gross Load Related	**445.9**	**387.5**	**594.3**	**-43.0**	**551.3**
Non Load Related	**479.6**	**427.3**	**696.8**	**-83.0**	**613.8**
Gross Capex less Non Op Capex	***925.5***	***814.9***	***1291.1***	***-126.0***	***1165.1***
Non Op Capex (Not Assessed)	16.8	20.0	51.0	0.0	51.0
Total Gross Capex	**942.3**	**834.9**	**1342.1**	**-126.0**	**1216.1**
Contributions	-243.7	-242.3	-233.2	7.9	-225.4
Net Load Related	**202.2**	**145.2**	**361.1**	**-35.2**	**326.0**
Total Net Capex	**698.6**	**592.6**	**1108.9**	**-118.2**	**990.8**
Non Load Related Summary					
Replacement			439.9	-83.0	356.9
ESQCR			4.4	0.0	4.4
Heath & Safety			14.0	0.0	14.0
Environment			21.0	0.0	21.0
Sub Total - Model Comparison	**0.0**	***257.5***	**479.3**	***-83.0***	***396.3***
Diversions		34.8	39.5	0.0	39.5
SCADA		7.7	21.5	0.0	21.5
Sub Total	***0.0***	***300.0***	***540.3***	***-83.0***	***457.3***
Metering (Not Assessed)		51.0	60.5	0.0	60.5
Sub Total	***479.6***	***351.0***	***600.8***	***-83.0***	***517.8***
Fault Capex (Not Assessed)		76.3	96.0	0.0	96.0
Non Load Related Total	**479.6**	**427.3**	**696.8**	**-83.0**	**613.8**

The forecast has been adjusted for:

- gross market LRE adjustment, to take account of customer connection expenditure by third parties
- pension funding deficit

- capitalised overheads
- inter-company margin and
- lane rentals.

The adjusted DPCR4 forecast is presented in the table below.

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

	Adjustment to DPCR4 Forecast					
Item	Gross Market LRE Adjustment	Pension Funding Deficit	Capitalised Overhead	Inter-company Margin	Lane Rentals Adjustment	**Adjusted DPCR4 Forecast**
Gross Load Related	29.0	0.0	-16.7	-7.1	0.0	**556.5**
Non Load Related		0.0	-13.8	-7.9	0.0	**592.1**
Gross Capex less Non Op Capex	***29.0***	***0.0***	***-30.5***	***-15.0***	***0.0***	**1,148.6**
Non Op Capex (Not Assessed)						**51.0**
Total Gross Capex	**29.0**	**0.0**	**-30.5**	**-15.0**	**0.0**	**1,199.6**
Contributions	-29.0	0.0	6.3	2.9	0.0	-245.1
Net Load Related	**0.0**	**0.0**	**-10.3**	**-4.2**	**0.0**	**311.4**
Total Net Capex	**0.0**	**0.0**	**-24.2**	**-12.1**	**0.0**	**954.5**
Non Load Related Summary						
Replacement		0.0	-10.8	-4.6	0.0	341.5
ESQCR		0.0	-0.1	-0.1	0.0	4.2
Heath & Safety		0.0	-0.4	-0.2	0.0	13.4
Environment		0.0	-0.6	-0.3	0.0	20.1
Sub Total - Model Comparison		**0.0**	**-12.0**	**-5.1**	**0.0**	***379.2***
Diversions		0.0	-1.2	-0.5	0.0	37.8
SCADA		0.0	-0.6	-0.3	0.0	20.6
Sub Total		***0.0***	***-13.8***	***-5.9***	***0.0***	***437.6***
Metering (Not Assessed)		0.0	0.0	-0.8	0.0	59.7
Sub Total		***0.0***	***-13.8***	***-6.7***	***0.0***	***497.3***
Fault Capex (Not Assessed)		0.0	0.0	-1.2	0.0	94.7
Non Load Related Total		**0.0**	**-13.8**	**-7.9**	**0.0**	**592.0**
Total Adjustments	**29.0**	**0.0**	**-30.5**	**-15.0**	**0.0**	**-16.5**

2.1.1 Load related capex

2.1.1.1 Network reinforcement

EHV reinforcement accounts for some 57% of the projected expenditure, 31% is allocated to 33/11kV reinforcement and the remaining 12% to 11kV and LV reinforcement.

With respect to a risk management approach to load related expenditure, EDF(EPN) have tended to quantify the risk by assessing the number of substations loaded above firm capacity. They consider that 48% (49) of grid substations and 53% (238) of primary substations are currently loaded to a greater or lesser degree above firm capacity and that only 1/3rd of primary substations (34.3%) have more than 2 MVA spare capacity available at all times throughout the year.

The ‘medium risk’ scenario tabled by EDF is intended to eliminate all substations at risk above 10% of time by 2012 and by 2015, the number of substations at risk above 5% of time would also be reduced. The ‘high risk’ scenario eliminates the substations at risk above 10% of time by 2015. Either scenario results in a considerable reduction in risk below the current level. At both the grid substation and primary substation levels, site specific and planned schemes have been forecast up to 2009 and beyond this, a more generic approach has been taken.

2.1.1.2 New connections forecast expenditure

EDF have examined the range of forecasts of new domestic customers from 2004 to 2010, ranging between 125,500 and 144,000 and have based their projections on a mid-range forecast of 136,800 or an annual increase of 20,300 rising to 23,750 in 2010. This compares with increases varying from 15,651 in 2001/02 to 19,700 in 2003.

The forecast increase in the number of domestic new connections is based on analysis of regional development plans and government targets.

2.1.1.3 Load related scheme papers submitted

Since only approved papers for major schemes have been tabled, largely for investments in the shorter term, it has not been possible to review the efficacy of reinforcement schemes of any magnitude for the middle years or later years of DPCR4.

The Aybury Grid and Primary Substation project is due to be completed in Mid 2005 and although there is no reason to consider that the investment is imprudent or less than efficient, sufficient information has not been provided to confirm this. The project is described as a key element of the strategy for coping with load growth in the Cambridge area and no alternatives to the proposed development are tabled in the Capital Authorisation paper provided.

With respect to the Thorpe Grid 132/11kV ICT project, although it is not possible to review the needs and proposed solution in detail and hence the efficacy of the scheme, the paper tabled describes 3 options that were considered and rejected before arriving at the preferred solution.

2.1.2 Comments and issues associated with load related expenditure

- EDF have estimated future expenditure requirements on the assumption that the number of substations would exceed firm capacity in the future in line with a 2% unit growth. However EDF say that load projections are based on load growth trends in addition to step changes but these two factors are not mutually exclusive. The use of unit growth rather than maximum demand growth to assess firm capacity is however thought to be appropriate but only if thermal modelling of transformer capacity relative to load curves is used to assess substation firm capacity, i.e. in addition to peak demand, the shape of the load curve is also of significance. However, EDF(EPN) have confirmed that all substations planned for reinforcement during DPCR4 are already loaded above firm capacity as determined by thermal modelling.

- A major issue to consider with respect to the Load Related Expenditure forecast is the degree of risk reduction proposed. As described by EDF, there would appear to be a significant number of substations where it is necessary to transfer load when one transformer is not in service in order to maintain supplies to customers. The point at issue is whether it is considered appropriate to reduce the risk described during DPCR4 since EDF's past investment policies, possibly developed under different ownership in response to incentive regulation, have resulted in the current level of risk rather than as a result of other factors outside their control.

- Since expenditure in the latter years of the period is based on generic type assessments, rather than site-specific schemes, it is disconcerting that the expenditure levels in these years rise so significantly.

- A further and significant factor is that the majority of schemes that have been included in the investment plan will be at the embryonic stage. They will not have been developed through a design stage nor will they have been subjected to optimisation considerations. As this process is regarded as one of the strengths of the NAMP process and one that has yielded savings in the past, it would be expected that future reductions in expenditure would also be achievable for the same reasons. It would be accepted that needs, assumptions and opportunities will all be refined and defined with the passage of time and when reviewed at the point of decision-making, an optimised scheme can be prepared.

All of the above factors would tend to generate a higher future expenditure requirement than one which would be generated if a different view had been taken as a basis for the projections but without doubt the approach taken to reduce the level of load related network risk below its current level is the major driver for the very high load related investment proposed.

2.1.3 Non-load related capex

Non-Load Related Capital Expenditure is addressed against:

- Performance based asset replacement;

- Environment, Health and Safety; and
- Asset Replacement.

These programmes of work with forecast costs are detailed more fully in Appendix A.

A programme of performance based asset replacement expenditure amounting to some £124m has been included. This programme of work is aimed at increasing the resilience of the network and it is not expected to contribute significantly to network performance under normal weather conditions. EDF subsequently transferred expenditure associated with resilience improvement to the DNO Alternative Case.

Of the major expenditure items in the environment, health and safety category:

- Fluid Filled Cable Replacement - allows lead sheathed 33kV cables to be replaced over a 20 year period and lead sheathed 132kV cables over a 25 year period
- Oil containment - addresses substations that do not have adequate bunding and is aimed at removing the risk of prosecution by 2007and
- Air Break Switch Disconnector expenditure - allows for the removal, replacement or refurbishment of switches on the 11kV and 33kV wood pole lines.

With respect to asset replacement expenditure, in their Base Case submission, EDF(EPN) state that:

> "…..A calculation has also been made as to which assets might need replacing in the period not due to the risk of failure, but to avoid creating problems for future periods where all the assets could start to fail over a relatively short period of time. This is done through a combination of assessing early indications of deterioration, life expectancy of the assets and the failure modes and impact of failure. If a large population of assets will require replacing in future price control periods, but the volumes that would need to be replaced are not feasible, then some have been brought forward into the DPCR4 period."

EDF have subsequently confirmed that the replacement of assets within the DPCR4 period will be driven by condition/operational risk/reliability and not some concept of a 'cliff face'.

EDF(EPN) also advise that Regulations, Quality of Supply, Reinforcement and Resilience considerations when taken together, may produce different asset replacement numbers from those projected by their Asset Replacement Model. The general modelling approach taken by EDF(EPN) has been to establish what is considered to be an acceptable age profile.

2.1.4 Comments and issues associated with non-load related expenditure

- EDF(EPN) have defined Performance Based Asset Replacement Expenditure as follows: 'These programmes are designed to increase the resilience of the network and hence reduce the risk of faults under severe weather conditions – but are not expected to contribute significantly to network performance under normal weather conditions.' EDF(EPN) also state that 'These are programmes that reduce the number or risk of faults. They improve storm resilience and stabilise CI and CML performance against a deteriorating network and increasing fault trends in the underground 11kV cable network.'

- The above programme of work amounts to £124m before the allocation of overheads. Since some of this expenditure is intended to increase network resilience, its inclusion in the Base Case is not in keeping with the guidance provided for the Base Case submission with respect to quality of supply as follows:" - Existing underlying levels of network resilience are maintained for the period to 2020 (i.e. no deterioration in the relationship between weather severity and number of faults and restoration times);" EDF subsequently agreed to move some of the performance improvement expenditure into the DNO Alternative Case.

- Before considering PB Power modelling outputs, the most significant issue arises again as a result of the approach taken to forecast asset replacement volumes. EDF consider that the replacement programmes that would be forecast by age profile/survivor curve modelling would be unmanageable unless the programmes are commenced as soon as possible. No benefits in terms of network performance or reduced operating costs are generally attributable to this approach other than a more manageable programme of asset replacement into the future. A comparison of asset lives shows that EDF's average asset lives are not significantly older than those of other companies but no other company is proposing to ramp up the rate of asset replacement on the same basis as EDF.

- It is also significant that where some companies expect an 80 year life from fluid filled cables, EDF(EPN) propose to replace all lead sheathed fluid filled cables before they are 70 years old. Although there is significant fluid leakage from <u>some cables</u>, it is not clear why EDF(EPN) foresees the requirement to replace <u>all</u> lead sheathed fluid filled cables within the time span proposed. However Ofgem is considering the requirement for replacing fluid filled cables as a specific financing issue.

- The projected age profile of the ages in 2015 compared against age profiles in 2003 would appear to indicate that the residual life of the asset base has been increased. The expenditure proposed is therefore more than is adequate to maintain the current level of asset risk until 2015. This would be consistent with the approach taken by EDF(EPN) to reduce the workload of asset replacement in future periods.

- It is not clear that the approach taken by EDF(EPN) in setting out discreet work programmes in the NAMP adequately addresses the interaction of the various programme elements in generic type programmes or the mutual benefits from the various categories. In particular, the expenditure both in the load related and non-load related categories is so high, and the volume of assets being replaced is so high, that it would be anticipated that fault rates would be affected and network performance improvement gains realised. The approach to 'Health Indices' modelling that EDF intend to adopt particularly relates fault rates for all asset classes to age and against this analysis forecasts the replacement volumes necessary to maintain fault rates or control them at a higher or lower level. Other companies who have already adopted 'Health indices' modelling are forecasting lower volumes of asset replacement requirements to those like EDF who use survivor curve models.

- EDF(EPN) consider that all assets planned to be replaced during DPCR4 are already in poor condition and, should condition monitoring develop or any other development take place (e.g. the adoption of forecasting based on Health Indices) that permits the further deferment of asset replacement in future regulatory periods, the expenditure in DPCR4 will not have been either unnecessary or inefficient. That is not to say that the expenditure is considered essential during the current period other than to offset further asset deterioration and to establish a longer-term asset management plan assuming asset deterioration as implicitly forecast by the asset replacement curves assumed by EDF.

2.2 Quality of supply/sensitivity scenarios

2.2.1 Network performance improvements

The following table sets out the proposed targets for the Ofgem QoS targets.

Table 2.3 - Network Performance Targets 2010 - 2020

02/03 actual		01/02 & 02/03 ave		2010 Scenario		2020 Scenario		(ave/2010)%	
CI	CML	CI	CML	CI	CML	CI	CML	CI	CML
89.8	77.6	94.8	76.2	85.3	68.9	71.1	57.9	111%	111%

EDF(EPN)'s quality of supply submission is described more fully in Appendix B.

EDF(EPN) consider that further work is required to establish that the 2020 targets are appropriate and that they are not achievable by extending current network performance improvement strategies based on automation and remote control.

EDF(EPN) have not considered the +/-2% scenarios since these are considered to be too sensitive to the normal volatility of network performance but consideration has been given to the +/-5% scenarios.

EDF(EPN) consider that the 2020 benchmarks set for EDF(EPN) may be achievable by adopting network development strategies based on, "Tessellated" networks using 3 leg spine circuits and zonal ring systems, dynamic MV networks with pre-fault configuration and adaptive protection, reconfigurable "modular" LV networks and on-line condition monitoring triggering pre-fault risk management action.

The estimated additional expenditure, over and above that set out in the DNO Alternative Case, for developing the networks as described above is £550m over 15 years for the EPN network (+£41m/-£7m for the +/-5% sensitivities). The estimates were based on extrapolation of conceptual network designs. A breakdown of the cost estimate has not been provided.

2.2.2 Resilience undergrounding

EDF(EPN)'s have tabled resilience undergrounding proposals amounting to £159m over the 5 year period and covering the networks at all voltages.

The expenditure savings associated with the undergrounding are estimated at £1.96m over the 5 year period.

2.2.3 Amenity undergrounding

EDF(EPN) have estimated the cost of amenity undergrounding in Areas of Outstanding Natural Beauty at £404m; almost half of this at the 132kV voltage level.

2.2.4 Comments and issues associated with the quality of supply scenarios

- EDF(EPN) have taken a high level approach to quality of supply improvement recognizing that there are limited returns to be gained from further automation and remote control.
- The submission for the 2020 targets is largely descriptive in nature with little analysis or justification for the particular proposals tabled and with no supporting details of consideration of options and costs.
- The submission is therefore largely tentative and insufficient to allow serious consideration to be given to the proposal.

2.3 DNO Alternative case

As described previously, EDF(EPN)'s approach to developing the 3 submissions was to establish its alternative scenario based on its NAMP process and to extract the network performance improvement expenditure and work programmes from this to establish the Base Case Scenario.

The initial financial difference between the Base Case Scenario and the DNO Alternative and totals £46.9m. The additional expenditure includes approx £36m for network performance enhancement programmes and a further £13m for additional network security from generation connection costs. These programmes of work are detailed more fully in Appendix 3.

EDF have prepared graphs (in the NAMP Description of Work Programmes), reproduced below, showing how network performance is expected to improve as a result of the medium risk and high risk expenditure streams considered. It can be seen that the Ofgem Targets for 2010 lie comfortably within the range for the Medium Risk Investment Plan and less so for the Higher Risk plan.

EDF(EPN) consider that the performance achievable by 2010 by this expenditure cannot be further improved without the change of approach described under the QoS scenarios.

Chart 2.2 - Reproduced from EPN NAMP Description of Work Programmes

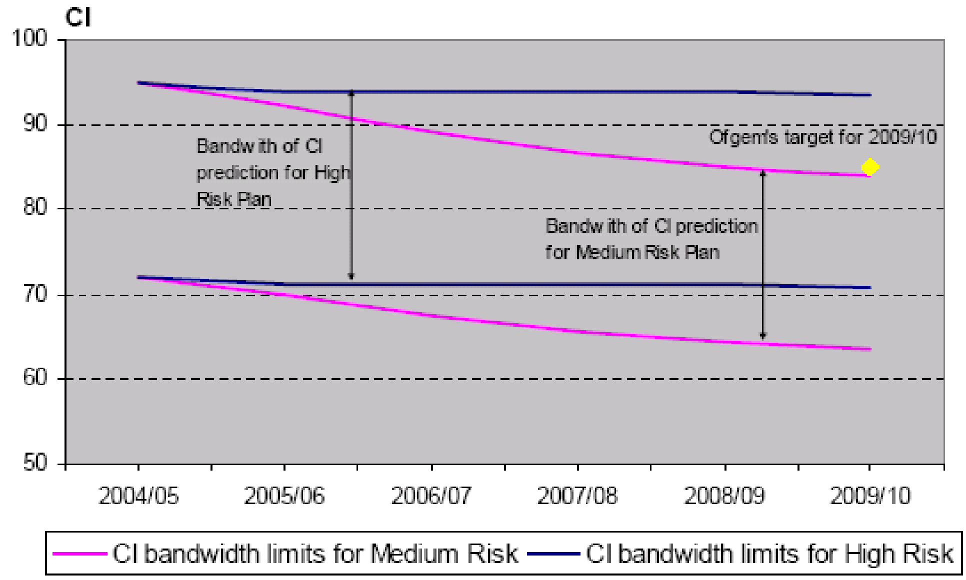
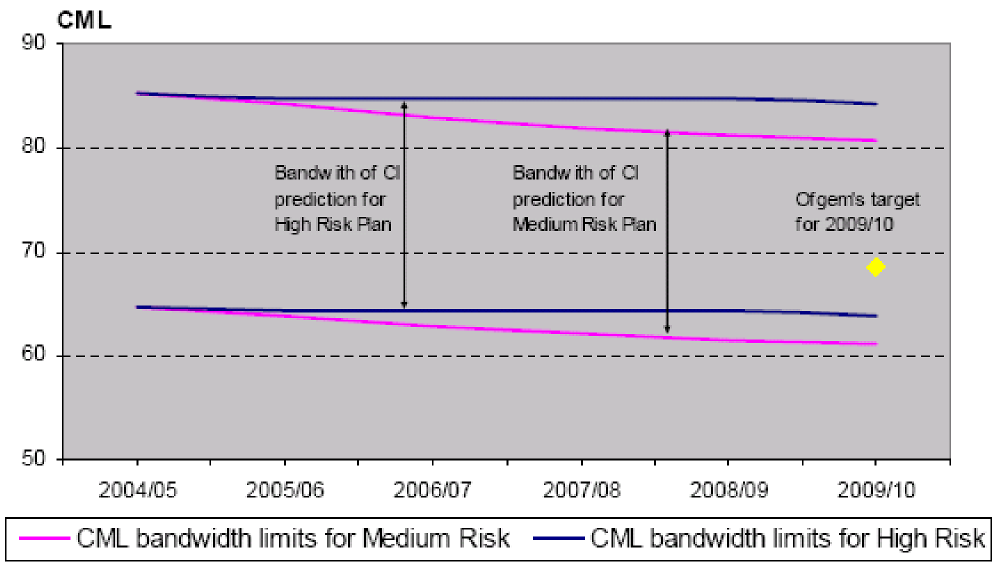


Chart 10.9 – CI performance estimate for the investment plans



2.3.1 Comments on DNO alternative scenario

- Since the DNO Alternative Scenario and the Base Case Submission are essentially identical prior to subsequent transfers with the exception of the network performance improvement expenditure identified, the comments set out in response to the Base Case Submission are equally applicable to the DNO Alternative Scenario.

3. PB POWER MODELLING AND COMPARISONS

3.1 Introduction

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

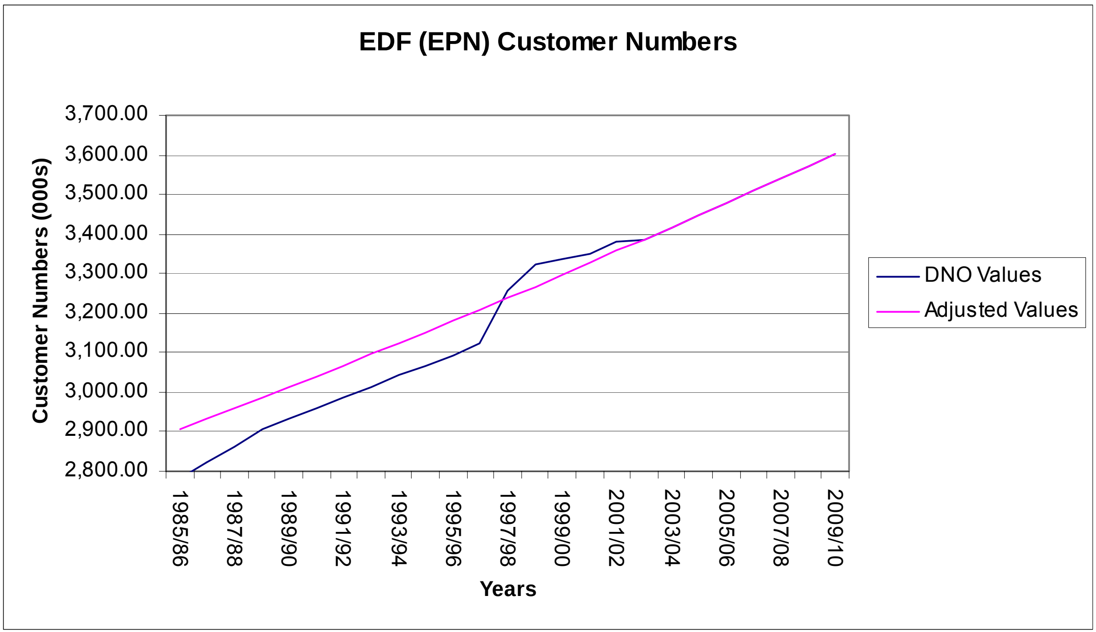
Detailed descriptions of the models are provided in Appendices D, E and F and the following sections discuss the validation and adjustment of the input variables and the model outputs.

3.2 Load related expenditure

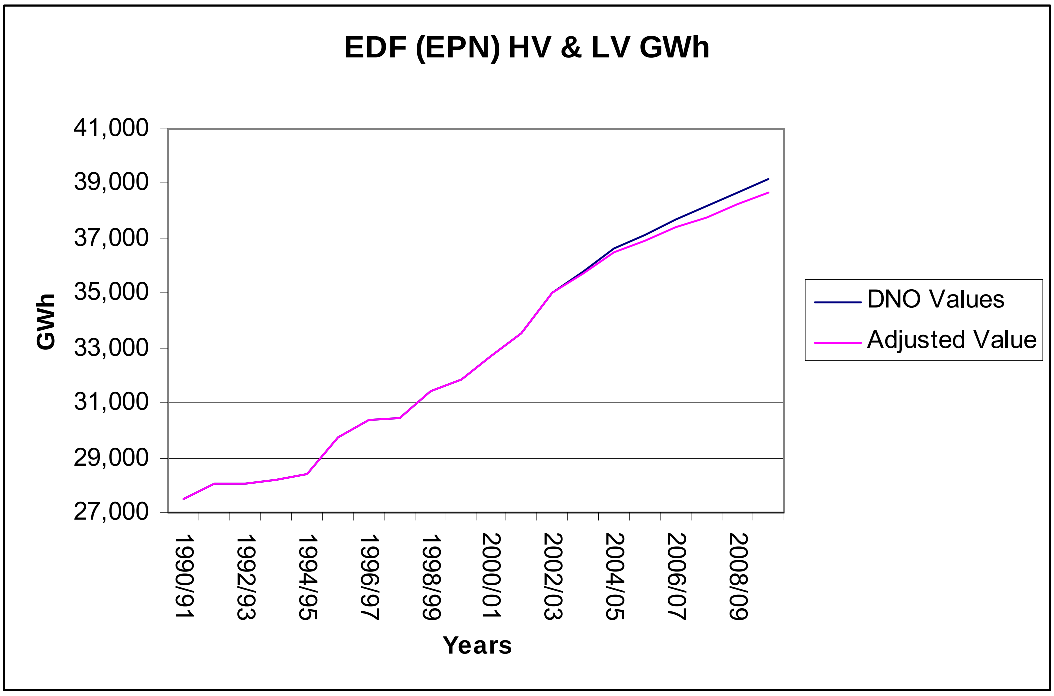
3.2.1 Model inputs

EPN's customer numbers have a significant step increase between 1997/98 and 2001/02. PB Power has removed this step by applying an average growth rate of 0.9% working back from 2002/03. The average growth rate has been calculated between 1989/90 and 1996/1997 and is similar to the forecast growth rate.

Figure 3.1 - Adjustment of Customer Numbers



The GVA analysis carried out as part of the load forecast review indicated that EPN's GWh values were high. To adjust the forecast to a more suitable level the GWh growth rate has been reduced year on year by 73 GWh from 2003/4 to 2009/10. The reduction of 73 GWh has been developed from a measure of GVA.



As the connection market is changing, EDF have submitted their Load Related Expenditure net of 3rd party connections. After questioning EDF on this matter the follow amendments have been made.

Table 3.1 - Adjustment to Forecast LRE to Reinstate Competition Reduction

	05/06	06/07	07/08	08/09	09/10
% Increase to EDF LRE	6%	8%	10%	12%	14%

3.2.2 Model outputs

The following table sets out the model output compared to DPCR 2 & 3 expenditure and DPCR4 submission. The DPCR4 submission for LRE has been increased to reinstate the reduction incorporated for competition in connections. The DPCR4 LRE figure has not been adjusted for expenditure that is considered unnecessary.

Table 3.2 - Load Related Capex Model Outputs[1]

LRE DCPR2 (excluding generation)	LRE DCPR3 (excluding generation)	Adjusted LRE Gross DCPR4 (excluding generation)	Model Output LRE for DCPR4 £m
(£m)	(£m)	(£m)	(£m)
327	381	600.4	**446.2**

3.2.3 Load related expenditure modelling comments

At first pass, the model output shows a significant reduction below the forecast expenditure.

When modelled over DPCR4 only rather than over DPCR2, 3 & 4, the model gives an output of £406m.

However, in order to check sensitivity, when a reducing 'Submitted DPCR4' figure is inserted into the model, the model is found to converge against expenditure of £400m.

3.3 Non-load related expenditure

3.3.1 Model inputs

No specific model input adjustments were made for EDF(EPN).

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.

[1] The DPCR3 projection was adjusted and the DPCR4 forecast was corrected at the end of October 2004, after the completion of the modelling the results of which were reported in Ofgem's Update Paper dated September 2004. The data, model output and PB Power opinion as stated in Tables 3.2 and 3.3 remain as prior to the October 2004 changes and are as the PB Power view reflected in the Update Paper. (The effect of re-running both the models would have been to indicate outputs slightly lower than hitherto.)

While the Executive Summary, Tables 2.1, 2.2 and 3.4 have been amended to reflect the October 2004 changes, the PB Power opinion on load and non-load related expenditure within these tables has remained unaltered.

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	117.8	116.3	Lines & services	127.3	155.0	127.3	
Cables	120.5	119.0	Cables & services	122.3	115.0	96.3	
Transformers	27.4	27.0	Substations	223.6	161.2	139.9	
Switchgear	128.6	126.9	Part Submission Total	473.2	431.1	363.5	
Services and Lines	14.5	14.4					
SMC	0.0	0.0					
Other Substations	70.5	69.6					
Other Not Modeled	0.0	0.0	Other Not Modeled	0.0		0.0	
Total	479.3	473.2	Total	473.2		363.5	363.5

3.3.3 Non load related expenditure modelling comments

The model generates significantly lower expenditure in the substation category even though the model output includes ground mounted distribution transformers that EDF advise are replaced mainly under fault conditions.

The model output is too high for the programme of work on overhead line lines considered necessary by EPN but modelled cable and services expenditure is close to that proposed.

Allowing EPN the full overhead line programme proposed and the modelled output for other categories of expenditure gives an allowance of £364m, a figure that is some 35% higher than the projected DPCR3 expenditure.

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	**387.5**	**556.5**	**446.2**	**446.2**
Non Load Related	**427.3**	**592.1**		**562.0**
Gross Capex less Non Op Capex	**814.9**	**1,148.6**		**1008.2**
Non Op Capex (Not Assessed)	20.0	**51.0**		51.0
Total Gross Capex	**834.9**	**1,199.6**		**1059.2**
Contributions	-242.3	-245.1		-245.1
Net Load Related	**145.2**	**311.4**		**201.1**
Total Net Capex	**592.6**	**954.5**		**814.1**
Non Load Related Summary				
Replacement		341.5		
ESQCR		4.2		
Heath & Safety		13.4		
Environment		20.1		
Sub Total - Model Comparison	***257.5***	***379.2***	**363.5**	***363.5***
Diversions	34.8	37.8		36.1
SCADA	7.7	20.6		8.0
Sub Total	***300.0***	***437.6***		***407.6***
Metering (Not Assessed)	51.0	59.7		59.7
Sub Total	**351.0**	***497.3***		**467.3**
Fault Capex (Not Assessed)	76.3	94.7		94.7
Non Load Related Total	**427.3**	**592.0**		**562.0**

Notes:

- Non operational capital expenditure has not been assessed
- Non-load related expenditure modelling covers all non-load related headings except diversions, metering, fault capex and SCADA
- Metering and fault capex are passed through
- Diversions are passed through, where compliant, with the Base Case the same as for DPCR3
- SCADA is separately assessed but not included in the modelling
- PB Power's asset replacement model output and Opinion are based on retirement profile modelling and exclude any additional expenditure that may arise under ESQCR legislation.

APPENDIX A

BASE CASE SUBMISSION

APPENDIX A – BASE CASE SUBMISSION

A.1.1 Actual and forecast capital expenditure projections 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 £262m and overall gross capital expenditure £901m.

Table A.1 - Actual and Forecast Expenditure Projection for DPCR3

£m @ 2002/03 prices	Actual		Forecast			
Capital Expenditure	**2000.0**	**2001/02**	**2002/03**	**2003/04**	**2004/05**	**Total**
Load Related	56.8	78.7	92.2	94.7	99.5	421.9
Capital Contributions	-35.5	-42.6	-64.0	-60.0	-57.8	-259.9
Non Load Related	90.5	74.3	87.6	98.7	108.0	459.1
Non-operational capex	0.1	0.4	2.2	9.9	7.4	20.0
Total Capital Expenditure	**111.8**	**110.8**	**118.0**	**143.3**	**157.1**	**641.1**

A.2 Base Case capital Expenditure Forecast for DPCR4

The Base Case Capital Expenditure projection for DPCR4 is summarised as follows:

Table A.2 - Base Case Capital Expenditure Forecast for DPCR4

£m @2002/03 prices	2005/06	2006/07	2007/08	2008/09	2009/10	Total
Capital Expenditure						
Load Related	112.7	117.8	119.0	122.3	122.6	594.3
Capital Contributions	-49.2	-47.4	-46.6	-45.3	-44.8	-233.2
Non Load Related	123.7	132.7	143.0	148.8	148.6	696.8
Non-Operational capex	8.0	10.0	13.0	11.0	10.0	52.0
Total Capex	**195.2**	**213.1**	**228.4**	**236.8**	**236.4**	**1109.9**

A.2.1 Projections of future load related capex

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

Table A.3 - Base Case Load Related Capex Projections

LOAD RELATED CAPITAL EXPENDITURE - £M	2005/06	2006/07	2007/08	2008/09	2009/10
Reinforcement	60	69	69	76	79
New Connections	60.4	58.5	57.8	56.5	56
LRE Total Gross	120.4	127.5	126.8	132.5	135
Customer Contributions	-49.2	-47.4	-46.6	-45.3	-44.8
LRE Total Net	**71.2**	**80.1**	**80.2**	**87.2**	**90.2**

A.2.1.1 Network reinforcement

When extracted from the Network Asset Management Plan (NAMP) (DNO Alternative Scenario – Table 17.6) the breakdown of Reinforcement Expenditure pre the allocation of overheads is as shown below.

Without interrogation of the NAMP on a line-by-line basis, it is not clear if any of the expenditure removed from the DNO Alternative Scenario to form the Base Case was included in the reinforcement category but if so, it is not expected to be significant.

Table A.4 - Reinforcement Expenditure

Reinforcement - £k	2005/06	2006/07	2007/08	2008/09	2009/10
33/11kV Reinforcement – Pmy S/s	15637	21369	14345	15250	17136
11kV Reinforcement	2650	2500	3000	4500	4250
EHV Substations	16256	15312	16413	16596	14210
EHV Switchgear	1575	1650	2474	4981	4118
EHV Circuits	8511	8084	14155	14145	16279
LV Reinf	1300	1300	1300	1225	1075
Total	**45929**	**50215**	**51686**	**56697**	**57067**

With respect to a risk management approach to load related expenditure, EDF(EPN) have tended to quantify the risk by assessing the number of substations loaded above firm capacity. They consider that 48% (49) of grid substations and 53% (238) of primary substations are currently loaded to a greater or lesser degree above firm capacity and that only 1/3rd of primary substations (34.3%) have more than 2 MVA spare capacity available at all times throughout the year.

17% of the substations loaded above firm capacity (40 primary and 10 grid) are forecast to be 'at risk' more than 10% of time over a yearly cycle in 2004. The degree of overload has not been quantified in the submission. EDF(EPN) has assumed that the number of substations 'at risk' will increase in line with the 2% unit growth rate and this assumption is used to assess the number of substations that will be at risk in the future rather than the MD growth rate of 0.92%. Load growth trends were calculated on a per substation basis, together with the addition of known step-changes, to predict the number of substations reaching nameplate capacity. The number of substations exceeding firm capacity for future years is therefore calculated on a localised rather than a global growth rate.

The numbers of substations at risk, primary and grid, are expected to rise to 65 and 18 respectively by 2018 and 115 and 31 respectively by 2015 unless reinforcement is provided. A factor of 0.8 was applied to the estimated number of substations forecast to be at risk to allow for saturation in some areas.

The 'medium risk' scenario tabled by EDF is intended to eliminate all substations at risk above 10% of time by 2012 and by 2015, the number of substations at risk above 5% of time would also be reduced. The 'high risk' scenario eliminates the substations at risk above 10% of time by 2015. Either scenario results in a considerable reduction in risk below the current level. At both the grid substation and primary substation levels, site specific and planned schemes have been forecast up to 2009 and beyond this, a more generic approach has been taken.

The key programmes of work being driven by load related expenditure are the replacement or reinforcement over the next 10 years of:

- 14% of the 132kV and 33kV transformers;
- 8% of 132kV steel tower OHL;
- 8% of 132kV switchgear; and
- 4% of 33kV switchgear.

This work addresses 106 primary sites and 35 grid sites. Examples of typical projects are:

- Aylesbury Grid - £2.8m
- Mill Hill - £1.5m
- Thames Gateway - £4.8m

- Harlow East - £4.2m
- Epping Grid - £1.3m

£1m has been added per year from 2005 to provide for EHV reinforcement work resulting from customer connections projects.

At the interface with NGT, reinforcement is proposed at Burwell (£0.75m), Rye House (£3.81m), Braintree(£1.2m), Rayleigh(£10m), Walpole(£2m), Tilbury(£1.5m), Mill Hill/Hendon (£8m), and Bramford (£1.2m).

A.2.1.2 New connections forecast expenditure

New connections expenditure and customer contributions are forecast as follows:

Table A.5 - New Connections Expenditure

£M	2005/06	2006/07	2007/08	2008/09	2009/10
New Connections	60.4	58.5	57.8	56.5	56
Customer Contributions	-49.2	-47.4	-46.6	-45.3	-44.8
New Connections - Net	10.8	11.1	11.2	11.2	11.2

A.2.2 Non-load related expenditure

The amount of non-load related expenditure projected by EDF(EPN) for the Base Case Scenario is as follows:

Table A.6 - Non-load related expenditure

Expenditure Classes	Non-Load Related (£m)					
	2006	2007	2008	2009	2010	Total
Non Fault Replacement	77.9	87.2	97.3	102.6	100.8	**465.8**
Metering	12.1	12.1	12.1	12.1	12.1	**60.5**
Faults	19.1	19.2	19.2	19.2	19.3	**96.0**
Diversions	8.1	7.7	7.6	7.8	8.3	**39.5**
Health and Safety	3.3	3.1	2.8	2.5	2.4	**14.0**
Environmental	3.2	3.4	4.0	4.6	5.8	**21.0**
Total	**123.7**	**132.7**	**143.0**	**148.8**	**148.6**	**696.8**

The following table sets out the programmes of work and expenditure included in the NAMP in the Performance Improvement Expenditure category. The expenditure tabled is pre the allocation of overheads.

Table A.7 - Performance improvement expenditure

£k	2005/06	2006/07	2007/08	2008/09	2009/10
Network Performance Enhancement Expenditure Plan			**£k**		
Enhanced Protection	664	633	550	550	550
Power Off Detectors	200	157	27	27	27
Fault Passage Indicators	8	31	100	100	100
Auto-Sectionalisers	200	263	50	50	50
Automation & Remote Control	2077	2077	2077	2077	1797
2nd Stage Protection	208	208	208	208	208
ICT	80	80	80	80	80
Total	**3437**	**3449**	**3092**	**3092**	**2812**
Performance Based Asset Replacement Expenditure					
Improved Earthing	120	38	38	38	38
Replace Low Strength Poles	1588	1700	1560	1139	1139
Protection Replacement	1384	1526	1447	1569	1437
Targeted O/h Line Components	2730	2655	2655	2655	2655
Small Section 11kV Cond Replacement	2063	2794	3413	3863	4200
11kV Truck Replacement	419	419	369	219	219
Undergrounding LV OHLs	3250	3250	3250	3250	3250
Installing ABC	3438	3588	3738	3899	4071
RMUs with automatic Feature and RMUs 2nd Stage Protection	3580	4198	4825	5452	5936
11kV Switchboard Replacement	2739	3799	4020	4149	4152
Total	**21311**	**23967**	**25315**	**26233**	**27097**

The expenditure excluded from the DNO Alternative Scenario Medium Risk scenario to form the Base Case Scenario is as follows:

Table A.8 - Expenditure excluded from DNO Alternative Case to form Base Case

Programme - £m	2005/06	2005/07	2007/08	2008/09	2009/10
Network Performance Enhancement Programmes	5.0	6.7	7.4	8.5	8.4
Network Resilience Programmes	0.7				
Additional Generation Connection Costs and Security Improvement	4.3	1.5	2.5	1.9	
Total	10.0	8.2	9.9	10.4	8.4
Pre Overheads	8.2	6.7	8.0	8.4	6.8

It is assumed that the Network Performance Enhancement Programmes in the above table are largely those described in the previous table.

A.2.2.1 Environment, health and safety expenditure

The following table sets out the programmes of work and expenditure included in the environment, health & safety category. The expenditure tabled is pre the allocation of overheads:

Table A.9 - Environment, health and safety expenditure

Programme - £k	2005/06	2006/07	2007/08	2008/09	2009/10
Fluid Filled Cable Replacement	906	1125	1625	2125	3000
Replace Aluminium Cable Joint Plumbs	270	270	270	270	270
Remote Monitoring Equip	195	195	195	195	195
Oil Containment	759	755	755	755	755
Amenity	150	150	125	50	58
Asbestos Removal	41	34	27	5	5
Tower Lines	246	246	246	246	246
ABSD	1129	1129	1129	1129	1129
Substation Security	410	370	250	238	200
ESQC	245	200	153	13	13
Metal Clad Cut-outs	416	416	416	416	416
Under-eave Wiring	100	100	100	100	100
Safety - Operations future provision	104	104	104	104	104
UMS Rewireable fuses - shrouding	106	106	79	0	0
Total	**5078**	**5199**	**5474**	**5646**	**6491**

Of the major expenditure items in this category:

- Fluid Filled Cable Replacement - allows fluid filled 33kV cables to be replaced over a 20 year period and the fluid filled 132kV cables over a 25 year period. The oldest cable to be replaced would be 58 years old at 33kV and 65 years old at 132kV.

- Oil containment - addresses substations that do not have adequate bunding and is aimed at removing the risk of prosecution by 2007.

- Air Break Switch Disconnector expenditure - allows for the removal, replacement or refurbishment of switches on the 11kV and 33kV wood pole lines over an eight year period. It is not apparent why an eight year period is thought appropriate.

A.2.2.2 Asset replacement

The following table sets out the programmes of work and expenditure included in the asset replacement expenditure category. The expenditure tabled is pre the allocation of overheads.

Table A.10 - Asset Replacement Programmes of Work

Asset Replacement - £k	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**
Battery Replacements	717	736	766	779	794
Tower Line Refurbishment	2855	3138	3928	4855	5320
33kV Solid Cable Replacement	1500	1538	1913	2800	2950
33kV O/h line Wood Pole Refurb	3055	2334	2403	3091	2096
11kV Cable Replacement	1258	1395	1508	1658	1808
Misc HV Asset Replacement	1279	1294	1303	1312	1332
I & M Tech Improvement	60	60	45	0	0
LV O/h refurb & U/g	523	723	923	1092	1148
LV Steel Pole Replacement	313	313	313	313	313
LV Asset Replacement - ad hoc	1658	1819	1922	1985	2021
Service Replacement	1684	1714	1640	1358	1390
Civil Replacement	4933	5705	6222	6222	6222
EHV Sw Gr	2289	4852	11263	10176	6750
11kV Sw Gr	1673	2261	2661	3062	3463
EHV transformer	3488	3180	2300	2900	2900
Misc EHV Replacement	696	58	58	58	58
Repl Scada Hardware	1775	2980	3140	2900	2900
Total	**29756**	**34100**	**42308**	**44561**	**41465**

A.2.2.3 Forecasting methodology

EDF(EPN) explain in the NAMP Philosophy and Strategy document that the asset replacement programme of work is intended to address condition, safety, environmental, quality of supply performance and future age profile concerns by a risk-managed approach to targeting, prioritising, and optimisation of timing of replacement. In their Base Case submission, EDF(EPN) state that:

> "…..A calculation has also been made as to which assets might need replacing in the period not due to the risk of failure, but to avoid creating problems for future periods where all the assets could start to fail over a relatively short period of time. This is done through a combination of assessing early indications of deterioration, life expectancy of the assets and the failure modes and impact of failure. If a large population of assets will require replacing in future price control periods, but the volumes that would need to be replaced are not feasible, then some have been brought forward into the DPCR4 period."

EDF have subsequently confirmed that the replacement of assets within the DPCR4 period will be driven by condition/operational risk/reliability and not some concept of a 'cliff face'.

EDF(EPN) also advise that Regulations, Quality of Supply, Reinforcement and Resilience considerations when taken together, may produce different asset replacement numbers from those projected by their Asset Replacement Model. The general modelling approach taken by EDF(EPN) has been to establish what is considered to be an acceptable age profile.

Key assets are considered to be:

- 132kV & 33kV Steel Towers;
- LV Overhead Lines;
- 33kV Wood Pole Lines;
- 132kV and 33kV Switchgear;
- Distribution Switchgear;
- Fluid Filled Cables;
- 132 & 33kV Transformers; and
- 33kV Solid Cable.

A.2.2.4 Work programmes

The refurbishment of tower lines is driven by condition assessment reports submitted by field staff.

It is planned to refurbish 356km of 33kV wood pole lines between 2004 and 2008 and a further 398km from 2008 until 2014. In addition a programme of wood pole replacement is intended. 11kV o/h line refurbishment is addressed under the performance improvement asset replacement category. LV expenditure will be focussed on improving fault resilience by replacing bare LV mains with ABC and undergrounding LV mains where appropriate. It is planned to replace all LV steel poles in urban locations by the end of 2014.

The Medium Risk Plan allows for the replacement of the worst performing 33kV and 11kV solid cables or sections of cables or joints where appropriate.

The expenditure proposed is intended to replace all 132kV and 33kV breakers that are in a poor condition, are uneconomical to maintain, or to replace circuit breaker types with known defects. In addition the plan would replace 11kV switchgear known to be in a poor condition, types with known defects and some non-remote controlled switchgear would also be replaced for the expansion of the automation project.

The proposed programme makes allowance for the replacement of two grid and five system transformers each year due to condition and unexpected failure.

With respect to civil replacement, EDF consider that any sites requiring attention can be undertaken on a piecemeal basis and since the projected asset life of buildings is considered to be greater than that of switchgear, piecemeal refurbishment or replacement of the buildings is usually done at the same time as the switchgear refurbishment. However with respect to distribution substations, these have been surveyed and this has identified the requirement for the replacement of civil assets where they are in poor condition and high risk. EDF also consider that the historic expenditure levels for these assets have been too low and increased expenditure is now required to bring them up to standard.

Service replacement is driven by the need to comply with the ESQC regulations (high risk services and through-loft services) and to replace steel wire armoured services where necessary.

The following table has been reproduced from the EDF Base Case submission quantifying the volume of replacement activity included in the programme:

Table A.11 - Asset Replacement Volumes

Asset Programme	% of Total Population 2005/6- 2009/10	% of Total Population by 2014
132kV steel tower lines refurbished	28%	50%
11kV OHL refurbished	8%	14%
132kV switchgear replaced	25%	37%
11kV switchgear replaced (with SF_6 RMUs)	16%	30%
33kV OHL (wood pole and steel tower) refurbished	16%	30%
LV OHL refurbished	15%	30%
33kV switchgear replaced	24%	46%
lead-sheathed pressurised oil cable replaced	7%	17%

These volumes are in addition to those replaced under the Load Related expenditure programme:

- 14% of the 132kV and 33kV transformers;
- 8% of 132kV steel tower OHL;
- 8% of 132kV switchgear; and
- 4% of 33kV switchgear

APPENDIX B

QUALITY OF SUPPLY SCENARIOS

APPENDIX B – QUALITY OF SUPPLY SCENARIOS

B.1.1 Network performance improvements

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

Table B.1 - Proposed Network Performance Targets

02/03 actual		01/02 & 02/03 ave		2010 Scenario		2020 Scenario		(ave/2010)%	
CI	CML	CI	CML	CI	CML	CI	CML	CI	CML
89.8	77.6	94.8	76.2	85.3	68.9	71.1	57.9	111%	111%

EDF(EPN) consider that further work is required to establish that the 2020 targets are appropriate and that they are not achievable by extending current network performance improvement strategies based on automation and remote control. Furthermore EDF(EPN) consider that the QoS profiles representing their DNO case (in tables 15) are more appropriate since they are based on an understanding of the diminishing marginal costs of incremental QoS improvements and request that Ofgem gives greater credence to this scenario.

EDF(EPN) have not considered the +/-2% scenarios since these are considered to be too sensitive to the normal volatility of network performance but consideration has been given to the +/-5% scenarios.

EDF(EPN) have concerns that the benchmarking methodology is not robust insofar that it takes no account of annual performance variability and consider that the use of target ranges would be more appropriate. They consider that the benchmarks set for EDF(EPN) are unrealistic with current technologies but that they may be achievable by adopting network development strategies based on, “Tessellated” networks using 3 leg spine circuits and zonal ring systems, dynamic MV networks with pre-fault configuration and adaptive protection, reconfigurable “modular” LV networks and on-line condition monitoring triggering pre-fault risk management action. EDF(EPN) have not provided analysis to show why the proposed network development strategy is considered optimum.

The estimated additional expenditure, over and above that set out in the DNO Alternative Scenario, for developing the networks as described above is £550m over 15 years for the EPN network (-£7m, +£41m for the -/+5% sensitivities). The estimates were based on extrapolation of conceptual network designs. A breakdown of the cost estimate has not been provided.

The programmes of work proposed by EDF to bring about the network transformation are as follows:

Cables – Replace small section cables, undergrounding of MV OHL ccts, removal of multiple tee connections, additional feeders to reinforce systems and reduce customers per circuit length, reduction of high customer numbers on LV circuits.

Switchgear – Additional breakers for feeders above and remote control capability

Communications – High-bandwidth communications systems to support faster automation and real time condition monitoring and risk management.

Condition Monitoring – Widespread coverage of on-line cable partial discharge mapping and location technology embedded at primary substations and selected distribution substations.

Dynamic Earthing – Fault current limiting technology to allow reconfiguration before clearance.

B.1.2 Resilience undergrounding

EDF(EPN)'s proposals for resilience undergrounding are summarised in the following table

Table B.2 - Resilience Undergrounding Volumes and Costs

Voltage/Line Type	Kms	£m
LV lines	190.00	24.80
HV lines		
- Single circuit	385.00	23.79
EHV lines		
- 33kV single cct	80.00	30.62
- 132kV double circuit	45.00	79.94
Total Expenditure		**£159.15m**

The expenditure savings associated with the undergrounding are estimated at £1.96m over the 5 year period.

B.1.3 Amenity undergrounding

The EDF(EPN) estimates for amenity undergrounding in Areas of Outstanding Natural Beauty are as follows:

Table B.3 - Amenity Undergrounding Volumes and Costs

	Length of line km	Additional Expenditure £m	Expenditure savings £m	Net Incremental Expenditure £m
Overhead lines				
LV Lines	520.0	61.1	-0.4	60.7
HV lines – single cct	1000.0	55.3	-0.9	54.4
EHV lines				
- 33kV single cct	260.0	91.6	-0.1	91.5
- 132kV double cct	130.0	197.6	-0.1	197.5
Totals	**1910km**	**£405.6m**	**-£1.5m**	**£404.1m**

APPENDIX C

DNO ALTERNATIVE SCENARIO

APPENDIX C – DNO ALTERNATIVE SCENARIO

The financial difference between the Base Case Scenario and the DNO Alternative is set out as follows and totals £46.9m:

Table C.1 - Financial difference between DNO Alternative Case and Base Case

Programme - £m	2005/06	2005/07	2007/08	2008/09	2009/10
Network Performance Enhancement Programmes	5.0	6.7	7.4	8.5	8.4
Network Resilience Programmes	0.7				
Additional Generation Connection Costs and Security Improvement	4.3	1.5	2.5	1.9	
Total	**10.0**	**8.2**	**9.9**	**10.4**	**8.4**

The Network Performance Enhancement programmes include the following (costs are presented pre overhead allocation):

Table C.2 - Network Performance Enhancement programmes

£k	2005/06	2006/07	2007/08	2008/09	2009/10
Network Performance Enhancement Expenditure Plan			**£k**		
Enhanced Protection	664	633	550	550	550
Power Off Detectors	200	157	27	27	27
Fault Passage Indicators	8	31	100	100	100
Auto-Sectionalisers	200	263	50	50	50
Automation & Remote Control	2077	2077	2077	2077	1797
2nd Stage Protection	208	208	208	208	208
ICT	80	80	80	80	80
Total	**3437**	**3449**	**3092**	**3092**	**2812**

It is clear that expenditure additional to that described in the work programmes has been included in the network performance enhancement expenditure tabled above.

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.1.2 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.1.3 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.1.4 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.

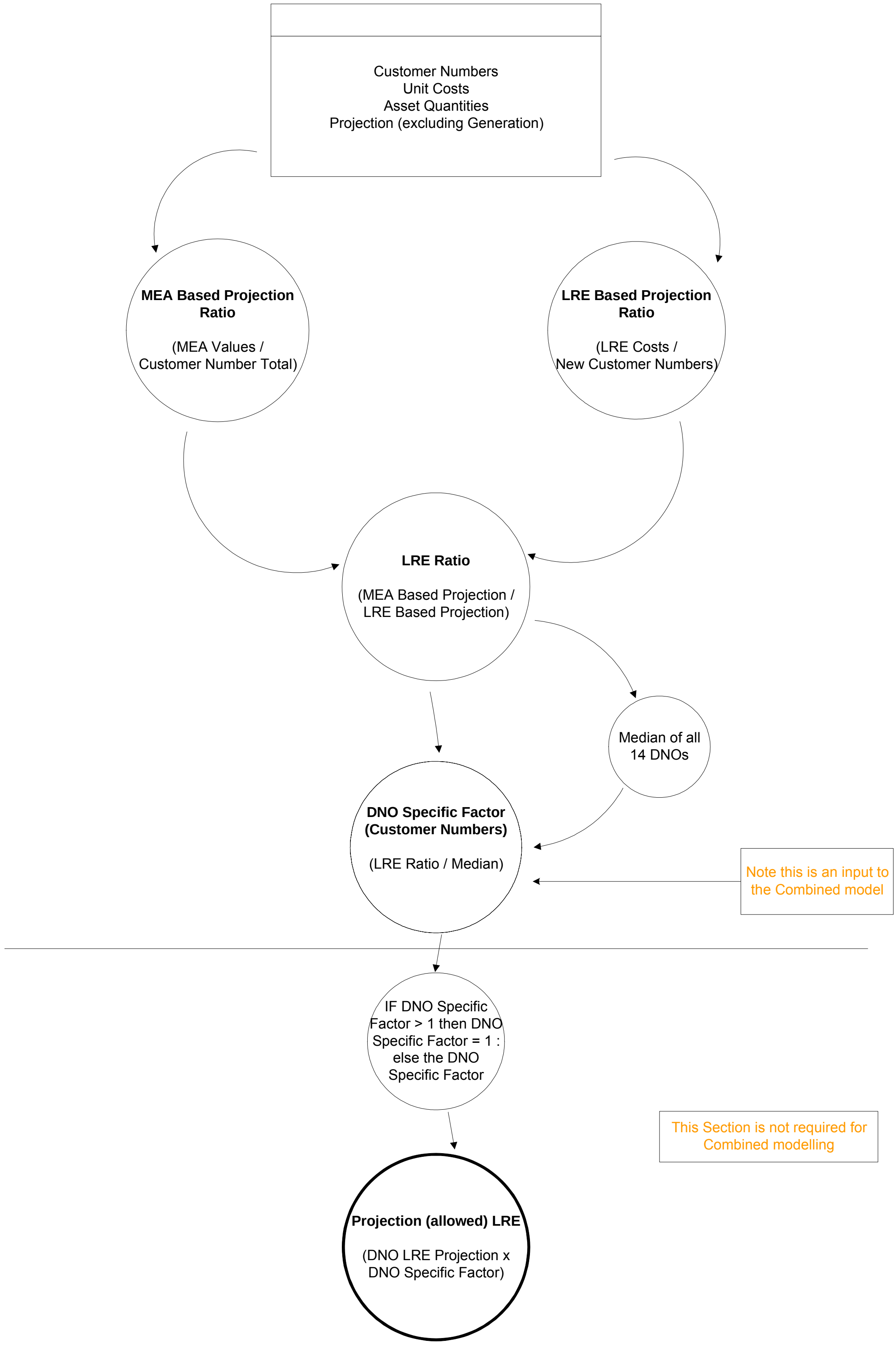
Being benchmarked on a median rather than on an average implies that extremes do not affect the adopted benchmarking position. It also means that the LRE of each company is compared relative to its cost base against the Industry Trend and not in absolute cost terms. This approach recognises therefore 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.1.5 Period of analysis

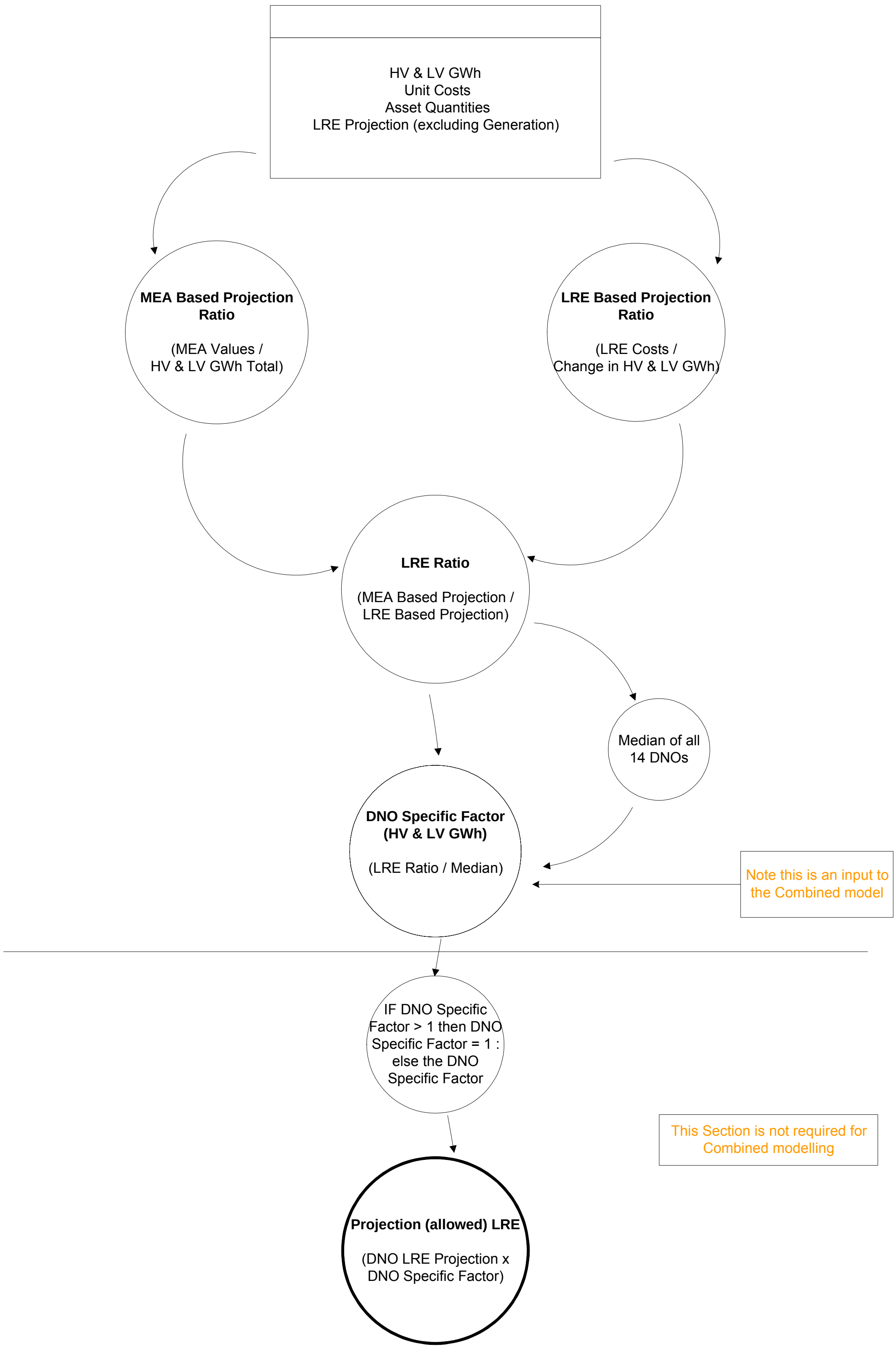
Although each DNO's network is comprised of a large number of smaller networks and that it would be expected that these would have a range of spare capacities depending on local load growth and when individual networks were last reinforced, it is possible that a larger number of the smaller networks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

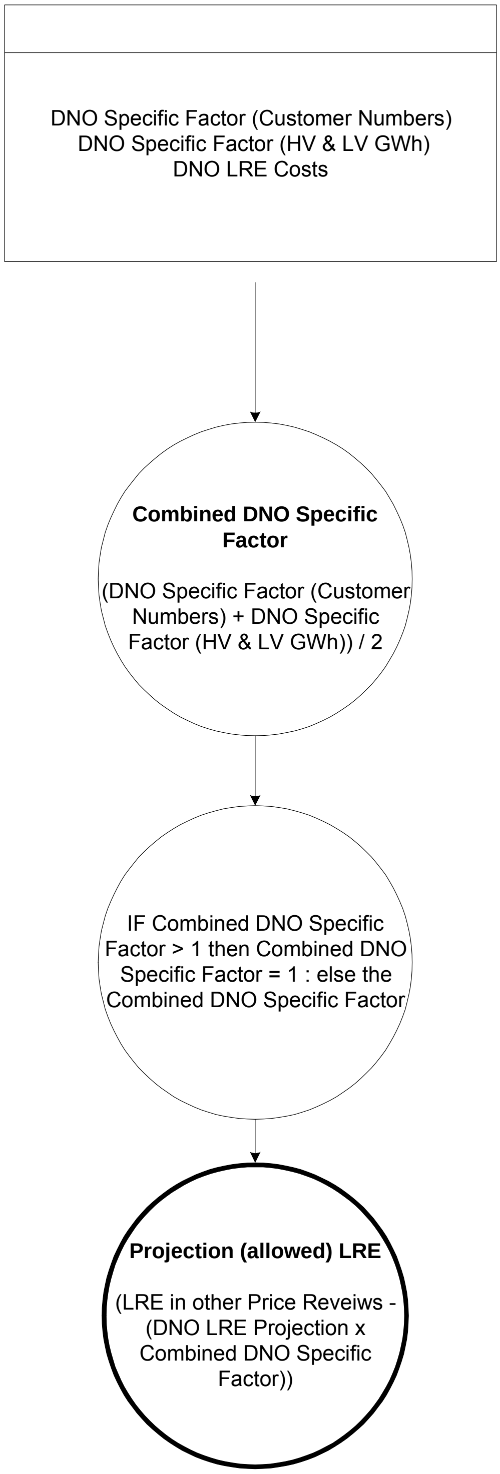
Combined Load Related Expenditure Modelling (Phase 1A Customer Numbers)



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]

---

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

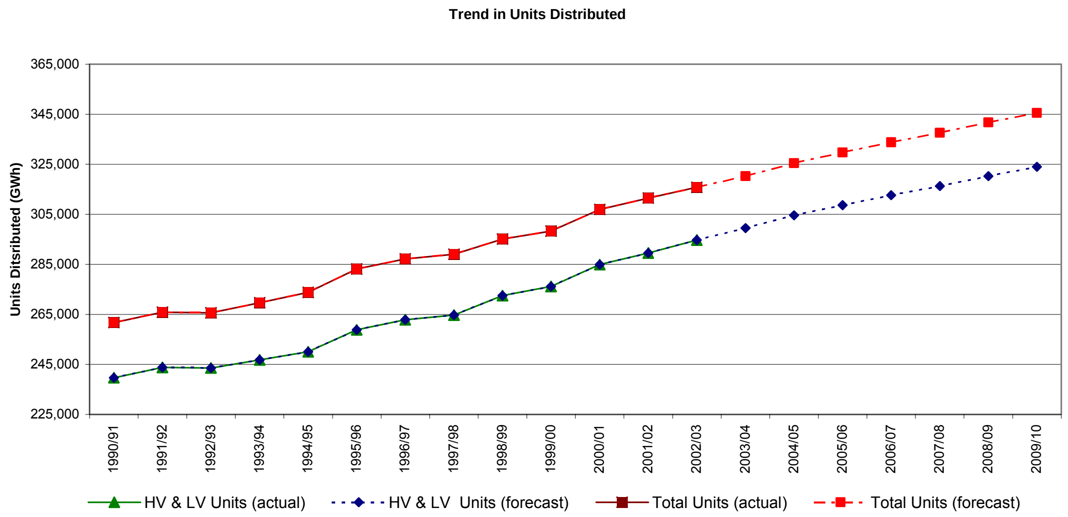
only. Statistics are published by geographical region in accordance with the Nomenclature of Units for Territorial Statistics (NUTS) classification. NUTS1 covers regions, NUTS2 covers sub-regions and NUTS3 covers unitary authorities or districts. At present NUTS2 data is available for the years 1995 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

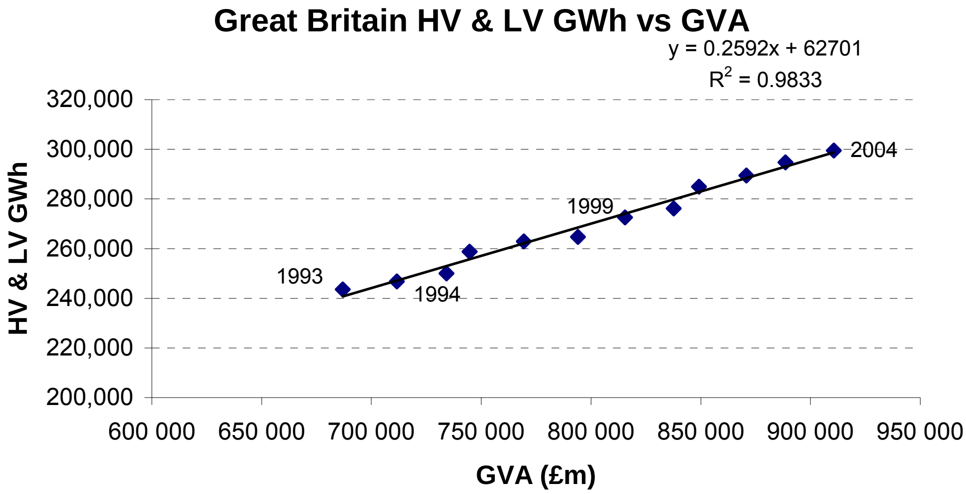


The total regulated units are HV and LV units and the total regulated units include EHV units. Up to and including 2003/03, the units distributed are actual units whereas from 2003/04 onwards these are forecast.

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.

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 2004[3] was used as the forecast for national growth. In a number of cases and, depending on the availability of published data, regional growth trends were estimated from the national trend but with a difference applied depending on the relative positions in 2003/2004.

[2] To align GVA and GWh data, ONS data for 2001 was treated as corresponding to the review year 2001/02 and so on.
[3] www.hm-treasury.gov.uk/media//E7910/ACF11CB.pdf, "Forecasts for the UK Economy", February 2004.

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

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

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

E.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:

- age profile
- retirement profile and
- unit cost.

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

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

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

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

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

F.1.1.2 Cyclic refurbishment / replacement

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

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

F.1.1.3 Assumptions

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

F.1.1.3.1 Overhead lines

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

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

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

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

F.1.1.3.2 Underground cables

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

F.1.1.3.3 Submarine cable

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

F.1.1.3.4 Benchmarking of DNO forecasts

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

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

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

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

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

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

- lines and services
- cables and services and
- substations

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

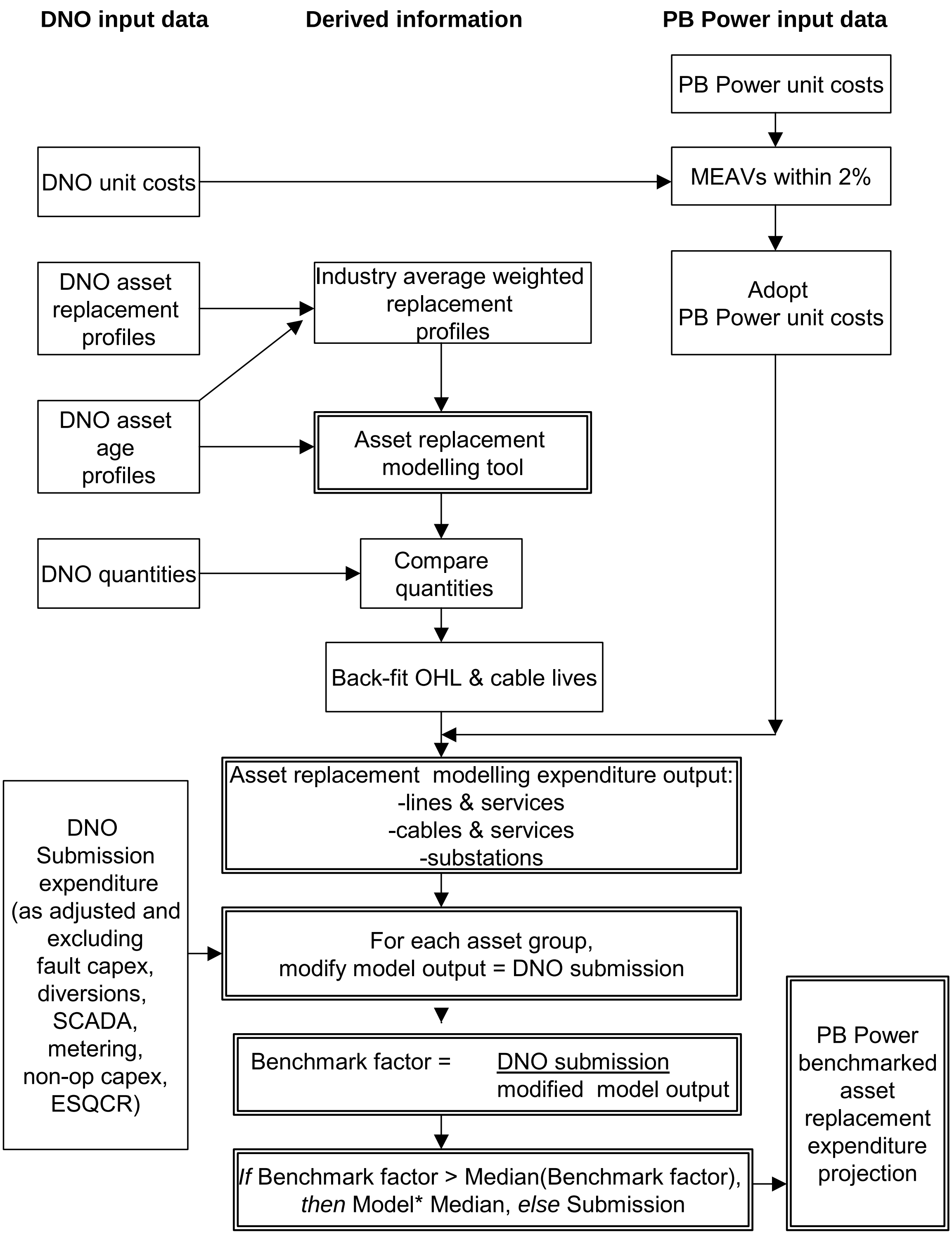
DNO submission/model output are calculated and medians (about unity) obtained. Where the benchmark factor exceeds the median (submission exceeds model output), the resulting benchmarked output is the model output multiplied by the median. Otherwise the benchmarked output is the submission itself. Minor miscellaneous amounts not specifically included within asset groups in the FBPQ submission have been treated as pass-through with minor adjustments.

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

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

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

ASSET REPLACEMENT BENCHMARKING FLOWCHART



APPENDIX G
UNIT COSTS AND MODERN EQUIVALENT ASSET VALUE

APPENDIX G – UNIT COSTS AND MODERN EQUIVALENT ASSET VALUE

PB POWER – SCHEDULE OF UNIT COSTS

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