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SP DISTRIBUTION

DPCR4 – FBPQ ANALYSIS AND CAPEX PROJECTIONS

OCTOBER 2004

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Final	21/10/04	All	Revision of model and allowance levels following DNO meetings with Ofgem and Ofgem September paper.			

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APPENDICES:

LIST OF ABBREVIATIONS

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

FOREWORD

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

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

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

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

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

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

EXECUTIVE SUMMARY

The following table summarises SPD'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	**217.0**	**311.5**	**61.6**	**254.0**	The model output indicatesan appreciable reduction that we have not been able to reconcile. Low growth and relatively high expenditure may suggest load movement (churn) although this has not been substantiated by SPD. We propose that the DPCR4 gross expenditure be increased over that projected for DPCR3.
Customer Contributions	(123.7)	(180.1)		(140.0)	
LRE Net	**93.3**	**131.5**		**114.0**	
Asset Replacement	148.9	244.8	**196.0**	206.0	The model output comprises a reduced line expenditure compared with the forecast, substation expenditure as per the forecast, but appreciably reduced cable expenditure reflecting SPD's shorter asset lives. Our opinion reflects an increase above model output for cables.
Other	142.9	162.3		149.3	£149.3m comprises diversions (£6.0m), SCADA (£8.7m), metering (£44.2m) and fault capex (90.4m).
NLRE Total	**291.8**	**407.1**		**355.3**	
Non Operational	11.6	0.0		0.0	
DNO Total	**396.7**	**538.5**		**469.3**	
DNO Total				*334.7*	*As Ofgem Sep 04 paper, excl. meters, faults, non operational and ESQCR*

Base case submission

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

The SPD forecast has been subject to adjustments in respect gross market load-related expenditure, capitalised overheads and inter-company margin.

Our principal findings are summarised below.

Load related expenditure

- In our opinion the load-related modelling process we have undertaken provides a sound indicator of investment for the industry. However the information provided by SPD has resulted in a modelled output that we have not been able to reconcile with the forecast. Further discussion and additional supporting information has not been able to bridge that gap. In the absence of additional data which clearly reconciled adjustments proposed with the original submission the decision has been taken to proceed with the original submitted data. It is possible that DNO-specific issues may exist and that these issues may be due to one or all of the following reasons:
    - differential industry churn level;
    - divergent domestic customer disconnection rate;
    - accumulation of excess inward investment expenditure provided for low demand utilisation customers;
    - high historical connection costs and
    - low growth rate that is more sensitive to inward investment need for network reinforcement compared to a higher load growth utility.
- SPD's normalised load-related expenditure is high, as
    - we calculate that over three price controls (DPCR2, DPCR3 and DPCR4 forecast) SPD's load-related expenditure per additional customer, normalised by MEAV per total customer, is about 13 per cent higher than the industry median, and
    - SPD's corresponding load-related expenditure per additional unit distributed, normalised by MEAV per total units distributed, is about twice that of the industry median.

Non load related expenditure

- The DPCR4 forecasts is high in part due to cost distortions incurred through rebalancing of overheads to Capex and profits on recharges; adjustments have accordingly been made to the forecast.

- SPD's submission is not entirely compliant as a Base Case forecast compared with those of other DNOs as SPD has a policy of replacing 33kV and 11kV interconnector overhead lines with a higher specification which represents an estimated £30m additional costs for resilience. However we would consider SPD's approach to be justified in view of recent storm experience.

- SPD's forecast includes cable replacement costs which we consider too high in view of the difficulty targetting poor condition assets for replacement.

- SPD's model has two outputs, fault and non fault replacement and indicates its overall replacement forecast may be low compared with other DNOs as more replacement is in faults. This will need to be resolved as the Ofgem review of replacement boundaries develops.

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

Load related expenditure

The model output indicates an appreciable reduction in expenditure that we have not been able to reconcile with the forecast. Low growth and relatively high expenditure may suggest load movement (churn) although this has not been substantiated by SPD. We propose an allowed gross expenditure for DPCR4 of £254m.

Non-load related expenditure

The model output comprises a reduced overhead line expenditure compared with the forecast, substation expenditure as per the forecast, but appreciably reduced cable expenditure reflecting SPD's shorter asset lives.

In PB Power's opinion the allowed asset replacement expenditure should be £206m, this amount excluding ESQCR related expenditure which is being reviewed separately. Our opinion reflects an increase above model output for cables. With the inclusion of diversions, metering and fault capital expenditure the corresponding overall non-load related expenditure would be £355.3m.

Conclusions

The above considerations would indicate that a total capital expenditure, net of customer contributions, of £469.3m would be appropriate.

1. INTRODUCTION

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

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

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

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

d. From consideration of the above we have formed a “PB Power opinion” of the proposed allowance.

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

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

2. DNO SUBMISSIONS

2.1 Base case

2.1.1 General

SPD's forecast is based on risk assessment techniques and the Base Case has a neutral affect on performance whereas, a matter of strategy, SPD has a target for industry average reliability and upper quartile network performance. However SPD has built network resilience into its forecast as its overhead line refurbishment programme is based on rebuilding the network over time to a more robust standard following experience with storms in DPCR3 and SPD's forecast may as a consequence be £30m higher than a strictly Base Case scenario. Since the DPCR4 forecast submission SPD has identified costs of compliance with ESQCR at an estimated cost of £10.3m, but ESQCR costs are being considered separately by Ofgem.

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

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

Item	DPCR3 Allowance	Adjusted DPCR 3 Projection	DPCR 4 Forecast	DPCR4 Corrections	Revised DPCR4 Forecast
Gross Load Related	**209.0**	**217.0**	**242.3**	**0.0**	**242.3**
Non Load Related	**221.3**	**291.8**	**452.8**	**6.4**	**459.2**
Gross Capex less Non Op Capex	***430.3***	***508.8***	***695.1***	***6.4***	***701.5***
Non Op Capex (Not Assessed)	16.8	11.6	0.0	0.0	0.0
Total Gross Capex	**447.1**	**520.4**	**695.1**	**6.4**	**701.5**
Contributions	-91.7	-123.7	-90.2	0.0	-90.2
Net Load Related	**117.3**	**93.3**	**152.1**	**0.0**	**152.1**
Total Net Capex	**355.4**	**396.7**	**604.9**	**6.4**	**611.3**
Non Load Related Summary					
Replacement	182.0		245.8	5.4	251.2
ESQCR			0.0	10.3	10.3
Heath & Safety			15.8	0.0	15.8
Environment			5.8	0.0	5.8
Sub Total - Model Comparison	**182.0**	**148.9**	**267.5**	**15.7**	**283.2**
Diversions	13.5	4.0	16.4	0.0	16.4
SCADA		6.8	19.5	-3.9	15.6
Sub Total	***195.5***	***159.6***	***303.4***	***11.8***	***315.2***
Metering (Not Assessed)	25.8	32.9	47.3	0.0	47.3
Sub Total	***221.3***	***192.5***	***350.7***	***11.8***	***362.5***
Fault Capex (Not Assessed)		99.2	102.1	-5.4	96.7
Non Load Related Total	**221.3**	**291.8**	**452.8**	**6.4**	**459.2**

Corrections made by SPD to the original forecast include an estimated £10.3m for work associated with ESQCR, classification of £5.4m of fault expenditure as replacement and a correction for Scada of -£3.9m.

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	102.1	0.0	-17.2	-15.7	0.0	**311.5**
Non Load Related		0.0	-22.3	-29.8	0.0	**407.1**
Gross Capex less Non Op Capex	***102.1***	***0.0***	***-39.5***	***-45.5***	***0.0***	**718.6**
Non Op Capex (Not Assessed)						**-**
Total Gross Capex	**102.1**	**0.0**	**-39.5**	**-45.5**	**0.0**	**718.6**
Contributions	-102.1	0.0	6.4	5.9	0.0	-180.1
Net Load Related	**0.0**	**0.0**	**-10.8**	**-9.9**	**0.0**	**131.5**
Total Net Capex	**0.0**	**0.0**	**-33.1**	**-39.6**	**0.0**	**538.5**
Non Load Related Summary						
Replacement		0.0	-17.8	-16.3	0.0	217.1
ESQCR		0.0	-0.7	-0.7	0.0	8.9
Heath & Safety		0.0	-1.1	-1.0	0.0	13.7
Environment		0.0	-0.4	-0.4	0.0	5.0
Sub Total - Model Comparison		**0.0**	**-20.1**	**-18.4**	**0.0**	**244.8**
Diversions		0.0	-1.2	-1.1	0.0	14.2
SCADA		0.0	-1.1	-1.0	0.0	13.5
Sub Total		***0.0***	***-22.3***	***-20.4***	***0.0***	***272.5***
Metering (Not Assessed)		0.0	-0.0	-3.1	0.0	44.2
Sub Total		***0.0***	***-22.3***	***-23.5***	***0.0***	***316.7***
Fault Capex (Not Assessed)		0.0	-0.0	-6.3	0.0	90.4
Non Load Related Total		**0.0**	**-22.3**	**-29.8**	**0.0**	**407.1**
Total Adjustments	**102.1**	**0.0**	**-39.5**	**-45.5**	**0.0**	**17.1**

2.1.2 Load related capex

SPD has provided a comprehensive explanation of its forecasting techniques at the HBPQ and FBPQ stage and these are not commented on in this report. SPD has based its load and new connections forecasts on cost trend line analysis which its own and external research shows is an indicator of the gross connections market. However this leads to a rising forecast against low growth in customer numbers and units. The trend line is also affected by the rising costs in DPCR3 due to SPD's rise in Capex due to rebalancing of overheads towards Capex and additional corporate costs. This will have contributed to the rising trend line to give a high forecast.

2.1.2.1 Network reinforcement

SPD is completing some major reinforcement investment in 2005/06 and the fluctuations thereafter are due to the timing of major projects. Reinforcement spend can be expected to be cyclical to a degree, since capacity is released in discrete blocks and SPD indicates that the levels of expenditure in DPCR4 are higher than DPCR3 due to urban renewal projects and public services, and commercial projects loss of capacity headroom.

Approximately 15% of SPD's primary sub-stations are currently operating within 8% of firm cyclic capacity. The number of primary sub-stations has seen a significant increase since 1999/2000. 64 primary sub-stations are now affected, relative to 43 in 1999/2000.

This lack of spare capacity is a cause of major concern to SPD and has implications for the application of commercial policies, resulting in a higher level of system reinforcement to be funded by the DNO.

SPD has provided information on major network reinforcements to relieve overloaded 33 kV substations (132 kV substations are treated as transmission in SPD) and provided information on major projects planned for the five years of the plan. SPD operates a risk points scoring methodology for prioritising these major projects as shown in Table A-4 in Appendix A and SPD has explained the rationale behind four projects. The methodology is considered robust but the timing of individual schmes is difficult to predict and the forecast is considered high.

2.1.2.2 New connections forecast expenditure

Historically new non domestic connections expenditure in Scotland has been relatively high due to its development area status, urban renewal and projects such as the Scottish Parliament. SPD has identified a number of projects of a similar nature going forward where these factors are said to continue, but we do not consider that there is sufficient evidence to indicates a continuing rising trend. Domestic growth is constant but the forecast shows a rise above the expenditure trend.

2.1.3 Comments and issues associated with the load related expenditure forecast

i. SPD has based its load and new connections forecasts on cost trend line analysis of total costs which its own and external research shows is an indicator of the gross connections market. However this leads to a rising forecast against low growth in customer numbers and units. The trend line is also affected by the rising costs in DPCR3 due to SPD's rise in Capex due to rebalancing of overheads towards Capex and additional corporate costs which will tend to give a higher forecast.

ii. Historically new non domestic connections expenditure in Scotland has been relatively high due to its development area status and urban renewal and projects such as the Scottish Parliament and SPD has identified a number of projects of a similar nature going forward where this is set to continue, but we do not consider that there is sufficient evidence to indicates a continuing rising trend but rather a steady level of investment.

iii. Major reinforcement schemes are in Table A-4 Appendix A are restricted to 33 kV as the 132 kV network is classified as transmission in Scotland. This classification is reflected in the PB Power modelling which is based on asset values and takes account of assets at 33 kV and below. SPD has more capacity headroom than SPM in its primary transformer capacity and SPD's investment programme addresses particular urban hotspots. The programme addresses substations that may be potentially overloaded in DPCR4. However in the event it is unlikely that all substations will necessarily be overloaded with the relatively low growth and so some reduction of the reinforcement programme should be made.

iv. With low levels of new domestic connections and only marginally overloaded substations, the load related programme is extremely sensitive to non domestic development which is volatile. The outturn requirements could be much lower than forecast. A more central case could be considered taking account of the DPCR4 forecast and the outturn for DPCR3 and modelling forecasts. It is possible that that the requirement for load related investment is likely to continue on current trends.

2.1.4 Non-load related capex

Overhead lines

SPD has developed overhead line specifications to take account of the effect of weather conditions in severe weather areas and normal weather areas and intends to progressively replace its main 33 kV and 11 kV interconnector lines to the new specifications as follows:

- severe weather area, represents 39% of SPD's HV overhead line network
- normal weather area, represents 61% of SPD's HV overhead line network.

'Storm resilient' overhead lines in severe weather areas are required to withstand a maximum combination of 70mph winds and 40mm diameter ice accretion.

'Low weather areas' are required to withstand 50mph winds and 40mm diameter ice accretion.

All inter-connected 33kV overhead lines would be storm resilient within 20 years in severe weather areas and 30 years in normal weather areas. 11kV inter-connected overhead lines would be made storm resilient within 15 years in severe weather areas and 40 years in normal weather areas. This represents a line strengthening rate of 144km per year in severe weather areas and 84km per year in normal weather areas. In this respect the SPD forecast may be some £6m per year higher than a strictly Base Case scenario. It is noted that the DNO case includes a further 450km of overhead line strengthening

SPD also indicates that in rural villages, there is a strong case for removing existing open wire overhead lines to enhance safety and reduce environmental impact. In some instances, old construction standards have resulted in inadequate clearances between open wire lines and buildings and other structures. The highest risk locations have been identified and are being rectified on a prioritised, programmed basis. When such lines are due for replacement a modern equivalent LV overhead line construction based upon ABC or undergrounding is being adopted.

SPD includes this safety work on LV overhead lines as work as part of normal risk assessed replacement.SPD has identified an expenditure programme of some £10.3m. SPD’s approach is considered to be beyond that required by the Base Case scenario due to the additional resilience and safety related LV overhead line work by around £48m. Nevertheless in view of storm experience the replacement of interconnector lines with a more resilient design is considered to be prudent and could be considered by Ofgem and DTI as a model for other DNOs in that the resilience expenditure is restricted to 33kV and interconnector lines, the timescales are reasonable and for less severe weather areas would only be completed when the lines need to be replaced. Spur lines are not to be strengthened.

Underground cables

SPD has identified certain strategic 33kV and 11kV cables which are deteriorating and have a steeply increasing replacement programme based on identifying specific sections for replacement. Forecast replacements rise from £3.1m to £18.7m We do not consider the increase to be justified due to the relatively static fault rate. The identification of deteriorating cable from partial discharge studies is not considered to be sufficiently advanced to enable this level of expenditure to be targetted.

Expenditure on replacement of service cables is similar to DPCR3.

Switchgear and transformers

Switchgear expenditure forecast for DPCR4 is similar to DPCR3. Although SPD is not proposing a programme to address the replacement of oil filled switchgear, SPD has adopted a procurement policy based on the purchase of non-oil filled switchgear.

Transformer replacements are forecast to be similar to DPCR3 although pole transformers are not only replaced on failure but also as a part of overhead refurbishment.

The expenditure on protection assets over the DPCR4 period is associated with replacement of under-frequency relay equipment (non-compliant with national requirements) and to address particular limitations associated with voltage control and sensitive earth fault protection for 11kV overhead lines.

Expenditure on Telecontrol/ SCADA of £19.5m over the DPCR4 can be attributed to addressing performance and support issues associated with RTU equipment in substations and control room SCADA system. This expenditure has not been fully investigated.

ESQCR Non load related investment

SPD has identified expenditure associated with compliance with ESQCR of £10.3m mainly on LV overhead line work.

2.1.4.1 Health and safety

Only a small proportion of SPD's investment is specifically allocated to safety and environment to address certain switchgear issues such as safety and asbestos.

2.1.4.2 Diversions

SPD has included amounts for diversions at historic rates in the forecast reflecting a robust approach to managing wayleave terminations.

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

i. The non-load related expenditure forecast is based on a robust risk assessment process, confirmed by asset replacement modelling and shows a significant rise from around £40m per year in DPCR3 to £70m per year at the end of DPCR4. SPD's programme includes significant replacement of primary substations and troublesome 33kV underground cables. The investment included for cables particularly is high and it may be difficult to target successfully the replacement of these assets.

ii. SPD's approach to overhead line replacement is considered to be beyond that required by the Base Case scenario due to the additional resilience and safety related LV overhead line work by around £48m. Nevertheless in view of storm experience the replacement of interconnector lines with a more resilient design is considered to be prudent and could be considered by Ofgem and DTI as a model for other DNOs in that the resilience expenditure is restricted to 33kV and interconnector lines and the timescales are reasonable and for less severe weather areas would only be completed when the lines need to be replaced.

iii. SPD uses a form of modelling which has separate algorithms for forecasting replacement and fault expenditure. SPD considers that this tends to allocate more of its expenditure to faults than replacement and that its forecasts of faults and replacement expenditure may not be comparable with other DNOs.

iv. SPD has suffered the serious effects of storms during DPCR3 which has led to a reappraisal of its overhead line design and replacement strategy. SPD has developed an enhanced line design for its severe weather areas, equivalent to the design envisaged for the enhanced line design scenario and plans to replace all interconnector lines over a period of time beyond DPCR4. SPD has many light construction (BS1320 design) lines installed during rural electrification and which are underdesigned by today's standards. In this respect SPD's Base Case includes line enhancement for its replacement lines but does meet Ofgem's requirement for maintaining existing levels of performance although resilience to storms is enhanced. We would consider SPD's proposals to be reasonable.

v. SPD has included relatively modest amounts for diversions, ESQCR and environmental improvements in the Base Case.

vi. SPD has a relatively low level of wayleave terminations and associated compensation and diversions as it takes a strong stance towards termination notices.

2.1.6 Major schemes submitted

Three largest schemes, SP Distribution 2005/06:

- Broomielaw reinforcement (£2,082k)
- Pilton Dr West / Trinity reinforcement (£1,650k)
- Lochwinnoch reinforcement (£1,649k)

Three largest schemes, SP Distribution 2006/07:

- Shrubhill switchgear (£3,444k)
- Johnstone switchgear (£1,323k)
- Govan switchgear (£1,768k) – (Papers not available)

The schemes provide a good level of justification for expenditure and include detailed risk assessments as a part of investment appraisal.

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
SPD	61.2	65.9	59.6	62.7	59.2	57.5	58.4	49.5	101%	109%

Scottish Power has a robust methodology for calculating the impact of investment on quality of supply and has provided a comprehensive summary by circuit type and plans through to DPCR6. SPD has indicated that it requires £29m to meet its quality of supply target directed at six circuit categories by improving the reliability of overhead lines, improving operational performance and the application of technology. These costs are considered reasonable to meet the Ofgem targets.

2.2.2 Overhead line upgrade

SPD has included only a modest figure of £20.7m for overhead line upgrade since its overhead line strategy of line strengthening is a feature of its ongoing asset replacement plans.

2.2.3 Resilience undergrounding

SPD has forecast £58m for resilience undergrounding

2.2.4 Amenity undergrounding

SPD would need to invest £73.4m for under grounding in National Parks and AONB s and does not favour under grounding in its own right for amenity purposes.

2.3 DNO alternative scenario

The DNO alternative includes a further 450 km of overhead line strengthening. SPD also includes adoption of low loss transformers for new installations and improvement of security of real time SCADA and network control systems. The additional cost of the DNO scenario is £48.1m.

3. PB POWER MODELLING AND COMPARISONS

3.1 Introduction

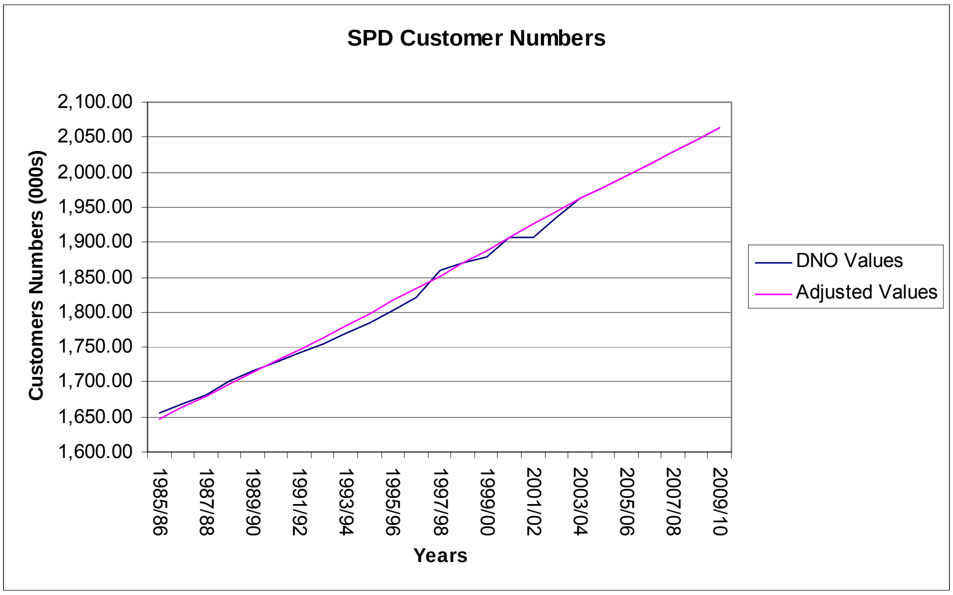
PB Power has carried out modelling of forecast expenditure using both DNO data and PB Power data with a view to understanding better how DNOs have arrived at forecast expenditure and with a view to informing Ofgem of issues that may be considered in arriving at allowances for DPCR4.

Detailed descriptions of the models are provided in Appendices D, E & 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

An average growth of 0.97% has been applied to the historic customer numbers. This has been used to remove the small amount of noise between 1997/98 and 2002/03.



SPD's own forecast of GWh has been adopted for modelling.

SPD submitted its load-related expenditure forecast net of 3rd party connections. Following discusssion with SPD and as indicated earlier in this report, a gross market LRE adjustment has been applied to SPD's forecast to reflect overall LRE.

3.2.2 Model outputs

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

Table 3.1 - Load Related Capex Model Outputs

LRE DPCR2 (excluding generation)	LRE DPCR3 (excluding generation)	Submitted LRE Gross DPCR4 (excluding generation)	Model Output LRE for DPCR4
(£m)	(£m)	(£m)	(£m)
232	217	311.5	**61.6**

3.2.3 Load related expenditure modelling comments

The modelling indicates that the SPD load-related expenditure, taken over DPCR2, DPCR3 and DPCR4, is high in relation to the corresponding increase in MEAV as indicated by growth in customers and in units distributed, particularly the latter. Furthermore a comparison of MEAVs calculated using SPD's and PB Power's unit costs show that the former are marginally high. After deducting the DPCR2 and DPCR3 expenditures from the overall model prediction, the balance of expenditure remaining for DPCR4 is low.

The modelled level of load-related expenditure for DPCR4 suggests that issues may exist that are specific to SPD. Historically SPD appears to be a provider with a relatively high cost per new service connection, which may be reflected in SPD's forecast of increased penetration by third parties offering connections. Furthermore the low level of growth on the network together with relatively high expenditure may suggest an underlying level of load movement (churn) whereas, for instance, a network with a high growth rate may more readily accommodate demand movement and/or stranded assets over a long period. The growth forecast by SPD in relation to the corresponding load-related expenditure is however low. Inward investment on brownfield sites is related issue that may well drive reinforcement need without associated growth indemand, depending on the nature of the load that eventually materialises. This phenomenon may also manifest itself through a higher cost per connected customer.

Some of the other network operators have to varying degrees identified similar issues. At present no substantive case has been made by SPD to suggest that it has a significantly worse set of factors that would allow the modelled output to be adjusted to accommodate such DNO-specific drivers.

Our review of the submission has has shown that there is no clear and unequivocal need for an increase in expenditure of the magnitude proposed by SPD. At the same time the model has identified an issue with regard to the comparability and completeness of the data submitted to support the forecast. Conversely, the model output indicates an appreciable reduction in expenditure that we have not been able to reconcile with the forecast.

Accordingly, we propose that the gross load-related expenditure to be allowed for DPCR4 be £254m.

3.3 Non-load related expenditure

3.3.1 Model inputs

No specific model input adjustments were made for SPD.

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

3.3.2 Model outputs

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

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

Submission	FBPQ Table 26	Adjusted submission	Combined	Adjusted submission	Model output	Bench-marked output	PB Power Opinion
Lines	112.5	97.8	Lines & services	112.2	107.6	112.2	
Cables	55.1	47.9	Cables & services	52.2	14.2	11.9	
Transformers	16.7	14.5	Substations	67.6	80.0	67.6	
Switchgear	45.8	39.8	Part Submission Total	232.0	201.8	191.7	
Services and Lines	21.5	18.7					
SMC	0.0	0.0					
Other Substations	15.3	13.3					
Other Not Modeled	5.9	5.9	Other Not Modeled	5.9		4.2	
Total	272.9	237.9	Total	237.9		196.0	206.0

3.3.3 Non-load related expenditure modelling comments

For overhead lines and services the model benchmarked output is slightly lower than SPD's forecast. For substations the model benchmarked output is higher than the forecast and so the latter is considered appropriate.

However in the case of underground cables, SPD forecasts (before adjustment) some £41.3m of HV cable replacement and £13.7m of EHV cable replacement. SPD's expected average asset lives are considerably shorter (52 years for HV and 42 years for EHV) than the adjusted industry average weighted lives derived by PB Power (Appendix F). Moreover the standard deviation declared by SPD for HV cables is long (22 years) and would tend to result in the modelling of earlier replacement activty. SPD's unit costs for replacement of HV and EHV cables are either the same as or lower than PB Power's. The differences in asset lives and standard deviations would explain the difference between SPD's submission and the model output. We would therefore conclude that SPD is proposing replacing HV and EHV cables at a much earlier age than the rest of the industry in general and may reflect difficulty targetting poor condition assets for replacement. This conclusion is also borne out by SPD's forecast cable replacement expenditure showing a rapid increase from £3.1m in 2006 to £18.8m in 2010.

In PB Power's opinion, the allowed non-load related expenditure corresponding to the model output should be £206.0m, the increase above the model output being an allowance for cable replacement. This amount excludes ESQCR expenditure, diversions, metering and fault capital expenditure. Furthermore ESQCR expenditure has been excluded from the overall total as this matter is being considered separately.

3.4 PB Power's opinion of allowances

Our findings are summarised in the table below.

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

Item	Adjusted DPCR 3 Projection	Adjusted DPCR4 Forecast	Model Output, benchmarked	PB Power Opinion
Gross Load Related	**217.0**	**311.5**	**61.6**	**254.0**
Non Load Related	**291.8**	**407.1**		**355.3**
Gross Capex less Non Op Capex	**508.8**	**718.6**		**609.3**
Non Op Capex (Not Assessed)	11.6	-		0.0
Total Gross Capex	**520.4**	**718.6**		**609.3**
Contributions	-123.7	-180.1		-140.0
Net Load Related	**93.3**	**131.5**		**114.0**
Total Net Capex	**396.7**	**538.5**		**469.3**
Non Load Related Summary				
Replacement		217.1		
ESQCR		8.9		
Heath & Safety		13.7		
Environment		5.0		
Sub Total - Model Comparison	**148.9**	**244.8**	**196.0**	**206.0**
Diversions	4.0	14.2		6.0
SCADA	6.8	13.5		8.7
Sub Total	***159.6***	***272.5***		***220.6***
Metering (Not Assessed)	32.9	44.2		44.2
Sub Total	**192.5**	***316.7***		**264.9**
Fault Capex (Not Assessed)	99.2	90.4		90.4
Non Load Related Total	**291.8**	**407.1**		**355.3**

Notes:

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

- PB Power's 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 Actual and forecast capital expenditure projection for DPCR3

In the table below we present the actual and forecast capital expenditure projection for DPCR3.

SPD's forecast reflects their anticipated loss of market share of the connections market. £71.5m has been added to gross expenditure and capital contributions in the DPCR4 forecast and £9.7m in the DPCR3 projection to reflect the total connections market on a comparable basis with other DNOs, historic expenditure and modelling. The adopted market is currently 34% and when the market matures SPD expects only 22% of the market to remain licensed.

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

	Actual			Forecast		Total
	2000/01	2001/02	2002/03	2003/04	2004/05	
Capital Expenditure						
Load Related Gross Market	45.3	40.6	68.1	63.2	60.2	277.4
Load Related SPD	45.3	40.6	68.1	59.6	54.1	267.7
Capital Contributions	-20.4	-23.8	-29.3	-20.6	-20.5	-114.6
Non Load Related	43.5	70.6	81.9	83.8	46.3	326.1
Non-operational capex	11.6	0.0	0.0	0.0	0.0	11.6
Total Capital Expenditure	80.0	87.5	120.7	122.8	79.9	490.9

A.2 Base case capital expenditure forecast for DPCR4

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

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

	Forecast					Total
	2005/06	2006/07	2007/08	2008/09	2009/10	
Capital Expenditure						
Load Related Gross Market	68.8	68.4	66.8	67.5	68.8	340.3
Load Related (SPD share)	58.0	56.0	52.7	51.2	50.9	268.8
Capital Contributions	-20.6	-18.7	-18.5	-16.8	-15.6	-90.2
Non Load Related	76.2	79.9	85.5	89.3	95.4	426.3
Non-operational capex	0.0	0.0	0.0	0.0	0.0	0.0
Total Capital Expenditure	113.6	117.2	119.7	123.7	130.7	604.9

Note that the above figures are presented without normalisation or adjustment for pensions, lane rentals profits on recharges or ESQCR.

Projections of future load related Capex

SPD'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**	**Total**
LRE Total Gross Market LRE	68.8	68.4	66.8	67.5	68.8	**340.3**
Total Connections Market	47.8	47.4	49.2	49.8	50.4	**244.6**
SPD,s loss of market share	10.8	12.4	14.1	16.3	17.9	**71.5**
SPD's Market Share of Connections	37.0	35.0	35.1	33.5	32.5	**173.1**
Customer Contributions SPD	20.6	18.7	18.5	16.8	15.6	**90.2**
Net Connections	16.4	16.3	16.6	16.7	16.9	**82.9**
Reinforcement from FBPQ	13.9	13.8	11.6	11.9	12.2	**63.4**
Other SPD funded LRE	7.1	7.2	6.0	5.8	6.2	**32.3**
LRE Total Net	37.4	37.3	34.2	34.4	35.3	**178.6**

The above table sets out the affect of the adjustments made for loss of market share. The table includes an amount for reinforcement as set out in the FBPQ and we have not been able to reconcile this declared reinforcement with the total net load related expenditure leaving some £32.3m of expenditure unexplained.

Network reinforcement

SPD has provided information on major network reinforcements to relieve overloaded substations at 33 kV and provided information on major projects planned for DPCR4.

Table A.4 - Network Reinforcement Programme

Summary of Major projects anticipated during DPCR4

								Project Summary						
								DPCR3			DPCR4			
								2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
Area	Activity	Description	Issue No.	Concept Approval	Weighted Score	Cat	**Total (£k)**	Load	Load	Load	Load	Load	Load	Load
West	31067	Mill St Ayr Primary Substation Reinforcement	40	N	2.425	R	**£750**	0	0	750	0	0	0	0
West	31066	Renfrew Ferry Braehead Park	41	Y	4.225	R	**£1,500**	0	0	0	750	750	0	0
Forth	31066	Gartarry Primary Reinforcement	43	N	2.95	R	**£800**	0	0	0	0	800	0	0
West	31066	Yoker Primary Substation	44	N	2.95	R	**£150**	0	0	0	150	0	0	0
Forth	31066	Nethertown Primary Substation	45	N	2.975	R	**£1,000**	0	0	0	0	1000	0	0
West	31066	Glenmavis Primary Substation	46	N	2.975	R	**£150**	0	0	0	150	0	0	0
Forth	31066	Gorgie Primary	17	Y	4.6	R	**£1,000**	0	0	0	0	500	500	0
Forth	31066	Netherdale Galashiels Primary	47	N	2.05	R	**£250**	0	0	250	0	0	0	0
Forth	31066	Wholeflats Primary Substation	48	N	2.825	R	**£1,000**	0	0	0	0	0	500	500
West	31066	Kilmarnock main	49	N	7.15	R	**£1,000**	0	0	0	0	0	500	500
West	31066	Grant St primary Substation	36	N	2.425	R	**£800**	0	0	0	0	0	0	800
Forth	31066	Colquhoun St Primary	37	N	2.425	R	**£500**	0	0	0	0	500	0	0
West	31066	Dumbarton Primary Reinforcement	38	N	2.825	R	**£500**	0	0	0	0	0	0	500
Forth	31067	Pilton Dr/Trinity 6.6kV Reinf	30	Y	5.75	R	**£962**	0	0	962	0	0	0	0
West	31067	Old Dumbarton Rd/Meadow Road 6.6kV Reinf	32	Y	3.475	R	**£1,338**	0	0	0	0	1338	0	0
West	31067	Broomielaw Reinf		Y		R	**£157**	157	0	0	0	0	0	0
West	31067	Lochwinnoch Primary Reinf		Y		R	**£500**	500	0	0	0	0	0	0
West	31066	Newarthill / Easterhouse Contingency		Y		R	**£60**	60	0	0	0	0	0	0
West	31067	Admiral St/Elizabeth St/St Andrews Cross 6.6kV R	32	Y	3.475	R	**£2,052**	0	0	0	2052	0	0	0
Forth	31066	New St Edinburgh Reinforcement	50	Y	3.325	R	**£1,319**	0	0	659.5	659.5	0	0	0
Forth	31066	Sighthill 33kV Board extension	28	N	3.125	R	**£1,600**	0	0	0	0	0	800	800
West	31066	Lockerbie Annan 33kv reinforcment	27	Y	3.05	R	**£1,500**	0	0	750	750	0	0	0
West	31066	Allanbank Lanarkshire	26	Y	1.95	R	**£1,500**	0	0	0	0	0	1000	500
Forth	31066	George Square Lane	16	Y	5.225	R	**£2,000**	0	0	1000	1000	0	0	0
Forth	31066	Glenrothes Pitteuchar/Southfield	25	Y	4.225	R	**£840**	500	340	0	0	0	0	0
West	31067	Glasgow City centre	4	Y	4.925	R	**£1,730**	0	0	0	0	0	865	865
West	31066	Bellshill Strathclyde Business Park	7	Y	5.1	R	**£1,200**	800	400	0	0	0	0	0
Forth	31066	Cultins Rd New Primary Substation	28	Y		R	**£0**	0	0	0	0	0	0	0
West	31066	Corra Linn	33	Y	3.575	R	**£300**	300	0	0	0	0	0	0
West	31067	Shotts/Almond Circuit	8	N	4.95	R	**£250**	0	250	0	0	0	0	0
Forth	31066	Wester Inch Bathgate	29	N	3.65	R	**£1,600**	0	0	1600	0	0	0	0
West	31067	Condorrat/Gartferry Rd	10	N	3.9	R	**£0**	0	0	0	0	0	0	0
West	31067	Abington/Crawford	9	N	4.725	R	**£250**	0	0	0	250	0	0	0
Forth	31067	Currie Primary	19	N	3.775	R	**£0**	0	0	0	0	0	0	0
West	31067	West George St Primary Substation	39	N	4.1	R	**£1,500**	0	0	0	1500	0	0	0
West	31066	Johnstone GSP	1	N	2.925	R	**£40**	0	40	0	0	0	0	0
Forth	31066	Lauder primary	3	N	2.775	R	**£100**	0	0	100	0	0	0	0
Forth	31066	Burghlee Primary	56	N	5.6	R	**£500**	0	0	500	0	0	0	0
		Additional Customer and General Reinforcement projects under £<50k						4560	2780	5529	4739	5212	6135	6135
		Additional circuits for new conn security								400	400	300	400	400
		SPD funded reinforcement for new conns (25% rule)								1400	1400	1200	1200	1200
		Total (consistent with table NC1.5)					**£30,698**	**£6,877**	**£3,810**	**£13,901**	**£13,801**	**£11,600**	**£11,900**	**£12,200**

SPD has explained the rationale behind four reinforcement projects as follows:

Pilton Dr West / Trinity reinforcement (£1,650k): This project is driven by load growth and system fault level issues in the north of Edinburgh. It was authorised in July 2003. The project will alleviate capacity, fault level and security of supply issues affecting an area designated for redevelopment and likely to be utilised for high profile commercial and domestic development along the waterfront and inland in the Granton area of Edinburgh. The project also facilitates competitive connections in the area and allows rationalisation of the 33kV network improving system reliability and removing exposure to environmental risks associated with old oil-filled equipment and noise complaints. The project is expected to be completed in March 2005.

Lochwinnoch reinforcement: This project in July 2003. Lochwinnoch town has a maximum demand of 5MW and is supplied via two 11kV feeders from Milliken primary sub-station. During the winter the voltage can fall outside statutory limits despite a locally situated voltage regulator. In addition, there have been complaints locally of voltage flicker the cause of which has not been pinpointed despite extensive investigation. To alleviate circuit overloading, voltage issues, and flicker it is proposed to provide Lochwinnoch with a new primary substation equipped with two 7.5MVA transformers. There will also be Quality of Supply benefits improving CI/CML figures for customers within Lochwinnoch.

Kilmarnock main primary S/S: This primary substation is equipped with two 12/24MVA 33/11kVA transformers. The maximum demand is currently 25MW and is projected to rise to 26.5MW. The transformers are to be up-rated.

Glasgow city centre : The 11kV cables in Glasgow city centre are presently overloaded in excess of of cyclic capacity and require to be overlaid with higher capacity cables.

New connections forecast expenditure

New connections expenditure and customer contributions are forecast as follows:

Table A.5 - New Connections Expenditure

NEW CONNECTIONS EXPENDITURE - £M	2005/06	2006/07	2007/08	2008/09	2009/10	Total
New Connections SPD	58.0	56.0	52.7	51.2	50.9	268.8
Customer Contributions SPD	20.6	18.7	18.5	16.8	15.6	**90.2**
LRE Total Net	37.4	37.3	34.2	34.4	35.3	**178.6**

Non-load related expenditure

The amount of non-load related expenditure projected by spd 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	44.9	48.9	53.0	57.0	61.6	**265.4**
Metering	4.8	4.6	4.4	3.4	3.6	**20.8**
Faults	19.4	19.8	20.4	20.9	21.6	**102.1**
Diversions	2.9	3.2	3.2	3.4	3.7	**16.4**
Health and Safety	3.0	2.4	3.3	3.4	3.7	**15.8**
Environmental	1.2	1.0	1.2	1.2	1.2	**5.8**
Total	**76.2**	**79.9**	**85.5**	**89.3**	**95.4**	**426.3**

This report does not refer to capitalised fault expenditure.

Overhead lines

SPD has stated that long-term modelling of this asset type using failure characteristics (PDF Curves) cannot reflect the impact of severe weather events, only performance under typical conditions. Therefore, whilst the long-term modelling outputs suggest an overall requirement to increase investment, these outputs do not take into account the additional levels of investment required to manage risks in the event of severe weather. It is therefore necessary to balance long-range investment forecasts for overhead lines with asset risk management techniques. This involves the detailed analysis of practical storm experiences and Metrological Office reports. As a result of analysis and practical storm experiences, SPD has further developed the methodology originally specified within EATS 43-40. This has enabled an approach to overhead line specifications that recognises the existence of geographic areas with greater exposure to severe weather events and the need for more robust specifications within those areas. The ratios between the two areas are as follows:

- severe weather area, represents 39% of SPD's HV overhead line network
- normal weather area, represents 61% of SPD's HV overhead line network.

'Storm resilient' overhead lines in severe weather areas are required to withstand a maximum combination of 70mph winds and 40mm diameter ice accretion.

'Low weather areas' are required to withstand 50mph winds and 40mm diameter ice accretion.

SPD has stated that replacement timescales have been developed taking into account wayleave, landowner and planning constraints. All inter-connected 33kV overhead lines would be storm resilient within 20 years in severe weather areas and 30 years in normal weather areas. Similarly, for 11kV the strategy would ensure that inter-connected overhead lines would be storm resilient within 15 years in severe weather areas and 40 years in normal weather areas. The 33kV overhead line network is a medium criticality asset, has circuit duplication and more robust 11kV interconnection. As a result, SPM has assumed that the high criticality 11kV overhead line network should be made storm resilient over a shorter period. Any extension beyond these timeframes would dilute the ability to achieve restoration of all customers during these events within a 2 to 4 day window. This represents a line strengthening rate of 144km per year in severe weather areas and 84km per year in normal weather areas. In this respect the SPD forecast may be some £6m per year higher than a strictly Base Case scenario. It is noted that the DNO case includes a further 450km of overhead line strengthening.

SPD has not completed the refurbishment information requested within Table 13.1 of the FBPQ. Where minor refurbishment is undertaken, it is performed to the existing overhead line specification standards and will not improve severe weather resilience. SPD only undertakes this form of minor refurbishment on non-interconnected sections of its overhead line networks (spurs) which have very few customers connected.

SPD considers that in rural villages there is a strong case for removing existing open wire overhead lines to enhance safety and reduce environmental impact. In some instances, old construction standards have resulted in inadequate clearances between open wire lines and buildings and other structures. The highest risk locations have been identified and are being rectified on a prioritised, programmed basis. When such lines are due for replacement a modern equivalent LV overhead line construction based upon ABC or undergrounding is adopted. The continued presence of overhead service lines to properties however, prevents the full benefits of wholly under-ground networks from being realised as replacement of services is often expensive and disruptive to customers.

SPD includes this safety work on LV overhead lines as work as part of normal risk assessed replacement. SPD has identified an ESQCR expenditure programme of £10.3m.

Table A.7 - Breakdown of proposed overhead line investment

Asset	2005	2006	2007	2008	2009	2010	Total
LV Overhead Lines	1.9	5.8	5.6	5.6	5.5	5.5	**28.0**
11kV Overhead Lines	8.1	13.5	13.6	13.9	13.8	14.5	**69.3**
33kV Overhead Lines	1.3	4.9	5.1	5.1	5.5	5.4	**25.5**
All Overhead Lines	**11.3**	**24.2**	**24.3**	**24.6**	**24.3**	**25.4**	**122.8**

Of the above about £2.7m per year is fault expenditure.

In summary SPD is proposing an increased level of investment in the DPCR4 period, relative to DPCR3, to improve reliability of LV overhead lines and enhance safety for the general public through removal of open wire LV overhead lines in rural villages. Due to local authority planning constraints, landowner consents etc., investment in 11 and 33kV overhead lines is subject to some degree of annual variation as indicated in the HBPQ submission. Proposed investment in 11 and 33 kV overhead lines is however, consistent with the average level of expenditure during DPCR3 and represents a continuation of the ongoing programme to reconstruct lines and improve storm resilience.

SPD's approach is considered to be beyond that required by the Base Case scenario due to the additional resilience and safety related LV overhead line work by around £48m. Nevertheless in view of storm experience the replacement of interconnector lines with a more resilient design is considered to be prudent and could be considered by Ofgem and DTI as a model for other DNOs in that the resilience expenditure is restricted to 33kV and interconnector lines and the timescales are reasonable and for less severe weather areas would only be completed when the lines need to be replaced.

Underground cables

SPD has identified certain strategic 33kV and 11kV cables which are deteriorating and have a steeply increasing replacement programme based on identifying specific sections for replacement. Forecast replacements rise from £3.1m to £18.7m We do not consider the increase to be justified due to the relatively static fault rate and identification of deteriorating cable from partial discharge studies is not considered to be a sufficient cause for the increase.

Expenditure on replacement of service cables is similar to DPCR3.

Switchgear and transformers

Switchgear expenditure forecast for DPCR4 is similar to DPCR3. This continued level of investment is necessary to manage the risks associated with ongoing disruptive failures, increasing numbers of reported switchgear defects and condition information including; increasing trends in SOPs (Suspension of Operational Practice), DINs (Dangerous Incident Notification) and ORs (Operational Restriction) as reported through the Electricity Association's NEDERS system (National Equipment Defect Reporting Scheme) over recent decades; and condition issues such as OR 49 (oil sludging) and Tyke (insulation deterioration), which have and will continue to, force increased replacement investment over the DPCR3 and DPCR4 periods.

Although SPD is not proposing a programme to address the replacement of oil filled switchgear, SPD has adopted a procurement policy based on the purchase of non-oil filled switchgear.

Transformer replacements are forecast to be similar to DPCR3 although pole transformers are not only replaced on failure but also as a part of overhead refurbishment.

The expenditure on protection assets over the DPCR4 period is associated with replacement of under-frequency relay equipment (non-compliant with national requirements) and to address particular limitations associated with voltage control and sensitive earth fault protection for 11kV overhead lines.

Expenditure on Telecontrol/ SCADA over the DPCR4 can be attributed to addressing performance and support issues associated with RTU equipment in substations and control room SCADA system.

ESQCR Non load related investment

SPD has identified expenditure associated with ESQCR of £10.3m..

3.4.1.1 Health and safety

Only a small proportion of SPD's investment is specifically allocated to Safety and environment to address certain switchgear safety issues asbestos etc.

3.4.1.2 Diversions

SPD has included relatively modest amounts for diversions in their forecasts reflecting the robust approach to managing wayleave terminations.

Major replacement projects

Table A.8 - Major Non Load Related Expenditure Projects

SP Distribution

Project Description	Activity	2005/06	2006/07	2007/08	2008/09	2009/10
Kilmarnock Town	33kV S/s Grid	■	■			
Shrubhill (Building)	33kV S/s Grid	■				
Johnstone GSP	33kV S/s Grid	■				
Govan 33kV Refurb	33kV S/s Grid	■				
Yair Bridge (HP)	33kV S/s Grid	■				
Inverkeithing Grid	33kV S/s Grid	■				
Kelvin Side	33kV S/s Grid	■				
Killermont	33kV S/s Grid	■				
Easterhouse Grid 33kV	33kV S/s Grid	■				
Tongland 11kV Switchgear	33kV S/s Grid	■				
Cupar	33kV S/s Grid		■			
Glenniston	33kV S/s Grid		■			
Kaimes	33kV S/s Grid		■			
Dunbar	33kV S/s Grid		■			
Bainsford	33kV S/s Grid			■		
Gorgie	33kV S/s Grid				■	
Telford Road	33kV S/s Grid					■
Elizabeth Street	33kV S/s Grid		■			
Saltcoats B	33kV S/s Grid		■			
Haggs Road	33kV S/s Grid			■		
Helensburgh	33kV S/s Grid			■		
St Andrews Cross	33kV S/s Grid				■	
Coylton	33kV S/s Grid					■
Warout Road Primary	33kV S/s Primary	■				
Renfrew Ferry Primary	33kV S/s Primary	■				
Kilbowie Primary	33kV S/s Primary	■				
Sherwood Primary	33kV S/s Primary	■				
Glenburn Primary	33kV S/s Primary	■				
Durie House Primary	33kV S/s Primary	■				
Barterholm Primary	33kV S/s Primary	■				
Candlemaker Row Primary	33kV S/s Primary	■				
Greenhill Road	33kV S/s Primary		■			
Annfield	33kV S/s Primary		■			
Wellesley Colliery	33kV S/s Primary			■		
Craigleith Drive	33kV S/s Primary			■		
Cowgate	33kV S/s Primary			■		
Kingsland	33kV S/s Primary			■		
Kirknewton	33kV S/s Primary			■		
Colinsburgh	33kV S/s Primary			■		
Bonnington Road	33kV S/s Primary			■	■	
Rannoch Road	33kV S/s Primary				■	
Kingsknowe Road North	33kV S/s Primary				■	
Earls Road	33kV S/s Primary				■	
Callender	33kV S/s Primary				■	
Penicuik	33kV S/s Primary					■
Gylemuir	33kV S/s Primary					■
Netherdale	33kV S/s Primary					■
Cousland	33kV S/s Primary					■
Methilhill	33kV S/s Primary					■
SGB Lurgi Primary	33kV S/s Primary		■			
Moffat Primary	33kV S/s Primary		■			
Ralston Primary	33kV S/s Primary		■			
Caterpillar Resite	33kV S/s Primary		■			
Kilmarnock Main (11kV)	33kV S/s Primary			■		
Carfin	33kV S/s Primary			■		
Eckford Street	33kV S/s Primary			■		
Kelvin Street	33kV S/s Primary				■	
New Cumnock	33kV S/s Primary				■	
Annan	33kV S/s Primary				■	
Balloch	33kV S/s Primary				■	
Glenmavis Gas	33kV S/s Primary				■	
Dumfries	33kV S/s Primary					■
Stewarton	33kV S/s Primary					■
Glenluce	33kV S/s Primary					■
Distribution OHL Programme	33kV/11kV & LV OHL	■	■	■	■	■
Switchgear OHL Programme	11kV Switchgear	■	■	■	■	■
33kV Cable Replacement Programme	33kV U/G	■	■	■	■	■

APPENDIX B

QUALITY OF SUPPLY SCENARIOS

APPENDIX B – QUALITY OF SUPPLY SCENARIOS

B.1 Network performance improvements

The targets assumed by Ofgem for 2010 and 2020 and the corresponding starting positions calculated by SPD are presented in the table below.

Item	Starting position 2004 and 2005	2010 Assumption	2020 Assumption
Unplanned Customer Interruptions (CIs)	61.1	59.2	58.4
Unplanned customer minutes lost (CMLs)	68.0	57.5	49.5

SPD has established the current level of performance for unplanned HV and LV CIs and CMLs by averaging the underlying performance reported for 2001/02 and 2002/03 using the audited IIP exceptional event adjustments. For EHV CIs and CMLs SPD has established the current performance to be equal to its average performance over the 10-year period 1993/94 to 2002/03. In making this calculation however SPD has taken into account the corrections to reported performance prior to 1997 that the company agreed with Ofgem to reflect changes in its reporting systems. The outcome is that SPD's programme is based on improving CIs by 3.1% and CMLs by 15.3% by 2010.

In establishing the 2010 and 2020 performance targets for each DNO, Ofgem made a number of key assumptions in relation to each of the 22 HV circuit groups (established as part of the disaggregation exercise conducted between Ofgem and DNOs). These assumptions are that within each of the 22 HV circuit groups DNOs will move towards achievement of:

- national average customers per fault – a measure of network design;
- national average faults per km – a measure of asset reliability; and
- upper quartile average duration of supply interruption – a measure of operational response.

B.1.1 Description of investments 2005 to 2010

In developing its investment plans to achieve Ofgem's QoS Improvement Scenario, SPD states that it has followed Ofgem's methodology and assumptions closely and analysed the gap between its performance and the industry average. SPD's analysis has shown that in the period to 2010, the most cost-effective improvements to global CI performance would be achieved by investments in the HV network. From the 22 HV circuit groups, SPD has identified ten groups which together account for over 65% of global CI and deliver below average CI per customer. These ten groups are also characterised by a lower quartile failure rate per km. For each of these ten circuit groups SPD has developed investment plans to improve 'faults per km' towards the national average for that group. These investments have been prioritised according to their cost effectiveness in terms of £/CI improvement and for DPCR4 the investment is directed towards six of the groups as shown below.

Summary of CI Investment by Circuit Category

Circuit Category	Activity	CI benefits	Cost (£m)
UG2B	Partial discharge testing to identify and replace underground cable sections prior to failure	0.31	2.055
MC2B	Maximise number of customers within the main protection zone, removal of performance defects and application of insulated shrouding to overhead line plant	0.31	3.151
MB1B	As MC2B.	0.14	1.821
OH1B	As MC2B.	0.29	4.6201
MB2A	As MC2B	0.59	10.153
MB1A	As MC2B	0.21	3.764
Total		**1.9**	**25.546**

SPD states that the 2010 CML target will be achieved by improvements obtained:

- as a by-product of CI initiatives;
- through operational initiatives; and
- through the application of technology solutions.

The Ofgem target of 57.5 CML equates to a 10.5 CML improvement. SPD has calculated that the CI initiatives targeted at the six circuit categories discussed previously during the DPCR4 period would, as a by-product, improve CML performance by 1.9 CML. Operational efficiency and technology initiatives are planned to address the remaining stretch of 8.6

CML. 7.5 CML would be achieved through business process and operational improvements.

SPD believes that the remaining 1.1 CML improvement could be achieved by installation of remote fault location and isolation facilities on 43 circuits (1.4% of total circuits). These 43 circuits are long, mixed, but predominately overhead line type circuits, in non-urban locations supplying more than 1000 customers. The circuits have typically developed over the years to supply villages and small towns, which in more recent years have experienced significant population growth.

Initiative	**CML Saving**	**% of CML Target**	**DPCR4 Capex (£m)**	**DPCR4 Opex (£m)**
By product of CI initiative	1.9	18.1		
Operational efficiency	7.5	71.4		4.550
Application of technology	1.1	10.5	4.023	
Total	**10.5**		**4.023**	**4.550**

The CML capital expenditure is directed to circuit categories as follows:

Circuit Category	**Number of Circuits**	**CML Benefit**	**Cost £m**
MA2A	15	0.2	1.419
MA2B	2	0.2	0.232
MB2B	3	0.1	0.279
MC2B	4	0.2	0.326
OH2B	6	0.1	0.511
OH3B	13	0.3	1.256
Total		1.9	4.023

B1.3 Ofgem sensitivity scenario three: further two per cent improvement in CML by 2010

The **additional** initiatives required to improve CI and hence CML performance by a further 2 % are shown below:

Circuit Category	**Activity**	**CI benefits**	**Cost (£m)**
OH3B	Maximise number of customers within the main protection zone, removal of performance defects and application of insulated shrouding to overhead line plant	0.23	4.620
OH2B	As OH3B	0.08	1.657
UG2A	Partial discharge testing to identify and replace underground cable sections prior to failure	0.076	17.179
MC1A	Maximise number of customers within the main protection zone, removal of performance defects and application of insulated shrouding to overhead line plant	0.13	4.816
Total		**1.2**	**28.272**

B.1.3 Ofgem sensitivity scenario five: further five per cent improvement in CML by 2010

Achievement of the 5% CML Improvement Sensitivity requires an extension of the technology solutions (remote fault location and isolation facilities) and the additional expenditure required is set out below.

The CML related capital expenditure is directed to circuit categories as follows:

Circuit Category	**Number of Circuits**	**CML Benefit**	**Cost £m**
MA2A	31	0.4	2.883
MA2B	44	0.7	4.092
MC1B	41	0.5	3.813
MC2A	46	0.8	4.278
MC2B	3	0.1	0.279
OH1B	30	0.4	4.185
Total		**2.9**	**19.530**

B.2 Overhead line upgrade

SPD has included only a modest figure of £20.7m for the accelerated overhead line upgrade since its overhead line strategy of line strengthening is a feature of its ongoing asset replacement plans.

SPD's Base Case proposals include the rebuild of 1140km of HV overhead lines to improve the safety and resilience of our networks within the period to 2010 in line with the timescales for the proposed HV overhead lines programme of:

- 15-year timeframe for HV overhead lines in severe weather areas; and
- 40-year timeframe for HV overhead lines in normal weather areas.

SPD states that these timescales are consistent with its assessment of what is achievable given delays associated with the wayleaves and consents process and resource availability.

In responding to the question on accelerated upgrade of HV overhead lines, SPD presents the costs and volumes associated with accelerating the Base Case HV overhead line modernisation programme by five years. The overhead line upgrade profile detailed within this sensitivity analysis has the following timescales:

- 10-year timeframe for HV overhead lines in severe weather areas; and
- 35-year timeframe for HV overhead lines in normal weather areas.

In order to accelerate the rebuilding of overhead lines by five years a total of 1560km of overhead lines would be targeted during the DPCR4 period, at an estimated cost of £20.7m. SPD has however qualified its response stating that resource constraints would preclude the accelerated line upgrade programme being delivered within the specified timescale. The response is therefore illustrative only.

B.3 Resilience undergrounding

SPD has forecast £58m for resilience undergrounding (of 2 per cent of overhead lines) but states that this is not achievable within the timescale proposed due to resource constraints and planning and consents issues.

B.4 Amenity undergrounding

SPD would need to invest £73.4m for under grounding in National Parks and Areas of Outstanding Natural Beauty. This scenario would imply the under-grounding of 552.6km of overhead lines. SPD does not favour under grounding in its own right for amenity purposes due to resource constraints and negative environmental factors.

APPENDIX C

DNO ALTERNATIVE SCENARIO

APPENDIX C – DNO ALTERNATIVE SCENARIO

C.1 DNO Alternative Scenario

SPD's DNO Alternative Scenario includes improvements in key outputs relative to the Base Case and a corresponding increase in expenditure over and above the Base Case of £48.1m capital expenditure and £5.4m operating expenditure during the DPCR4 period.

The DNO Alternative Scenario includes initiatives (additional to the Base Case) necessary, in SPD's view, to meet the expectations of customers, deliver a positive environmental impact and manage risk through:

- improvements in Quality of Supply (addressing worst served customers and
- communities and improving global CI / CML);
- installation of low loss distribution transformers; and
- real time system developments to mitigate the threat of terrorism.

Incremental volumes of work are shown below:

Activity	2006	2007	2008	2009	2010	Total
HV Overhead line bare (kms)	-51	-51	-51	-51	-51	-255
HV Overhead line covered (kms)	38.3	38.3	38.3	38.3	38.3	192
HV Cables	12.8	12.8	12.8	12.8	12.8	64
HV Switchgear Automation (Units)	11.0	11.0	11.0	11.0	11.0	55
Low loss transformers						
Real Time Systems Security						

Note: No additional transformers are planned. Instead existing 11kV ground mounted transformers would be replaced with low loss units, as and when due for replacement.

Additional capital expenditure (£m) is shown below:

Activity	**2006**	**2007**	**2008**	**2009**	**2010**	**Total**
Quality of Supply	9.18	9.18	9.18	9.18	9.18	45.9
Low loss transformers	0.06	0.06	0.06	0.06	0.06	0.3
Real Time Systems Security	0.79	0.82	0.13	0.17	0.0	1.9
Total	10.0	10.1	9.4	9.4	9.2	**48.1**

The incremental benefits of the DNO Alternative Scenario are shown in the table below:

Activity	**Reduction in**	**2006**	**2007**	**2008**	**2009**	**2010**
Quality of Supply	Unplanned CIs	0.0	0.4	1.2	1.7	2.1
Quality of Supply	Unplanned CMLs	0.9	3.0	5.5	7.7	10.4
Low loss transformers	Losses (GWh)	0.0	0.6	1.1	1.7	2.3

APPENDIX D

LOAD RELATED EXPENDITURE MODELLING

APPENDIX D – LOAD RELATED EXPENDITURE MODELLING

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

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

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

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

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

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

D.1.1.1 Analysis of demand growth

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

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

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

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

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

D.1.1.1 Analysis of new customers

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

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

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

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

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

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

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

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

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

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

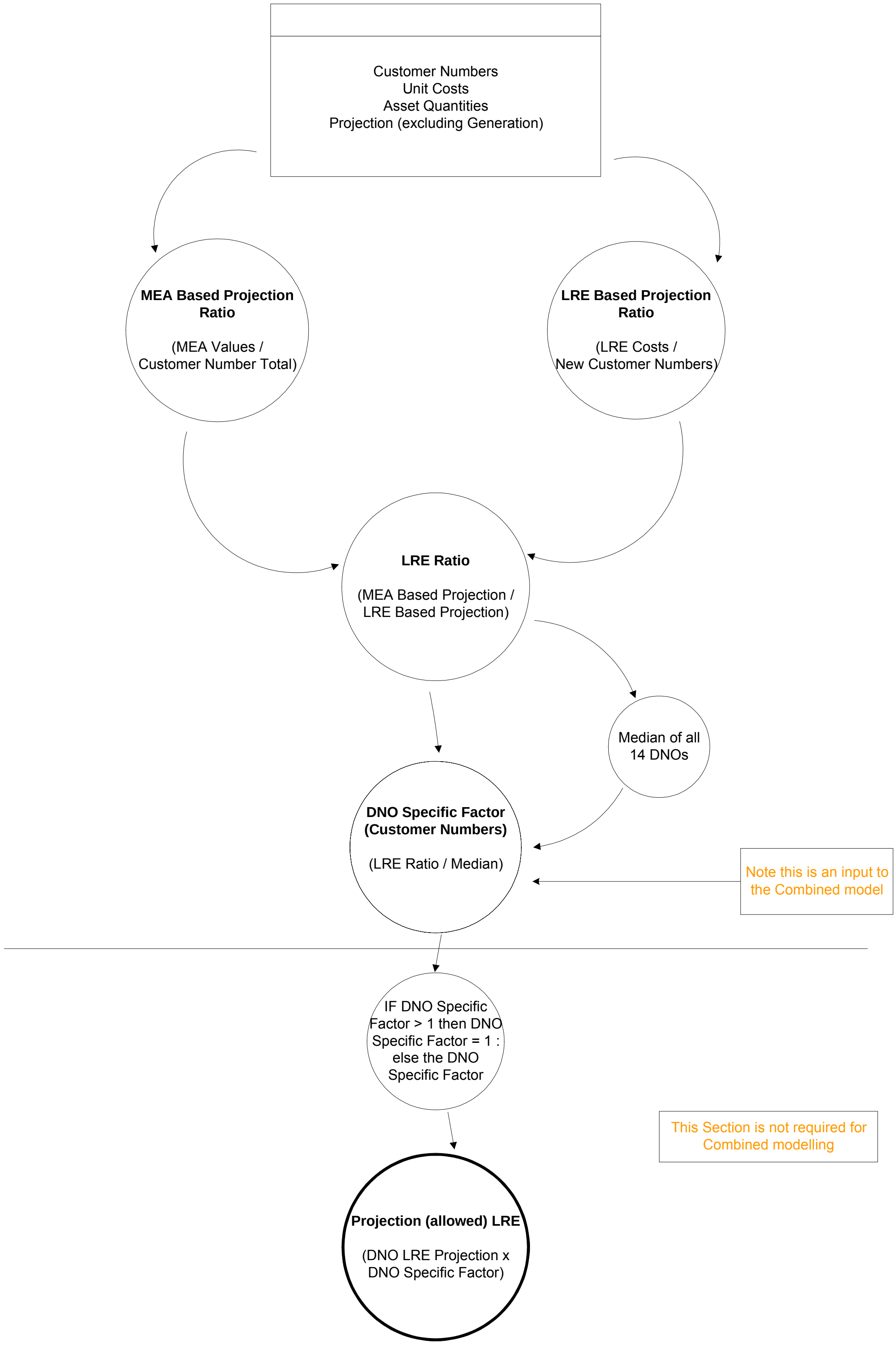
Being benchmarked on a median rather than on an average implies that extremes do not affect the adopted benchmarking position. It also means that the LRE of each company is compared relative to its cost base against the Industry Trend and not in absolute cost terms. This approach recognises therefore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

Period of analysis

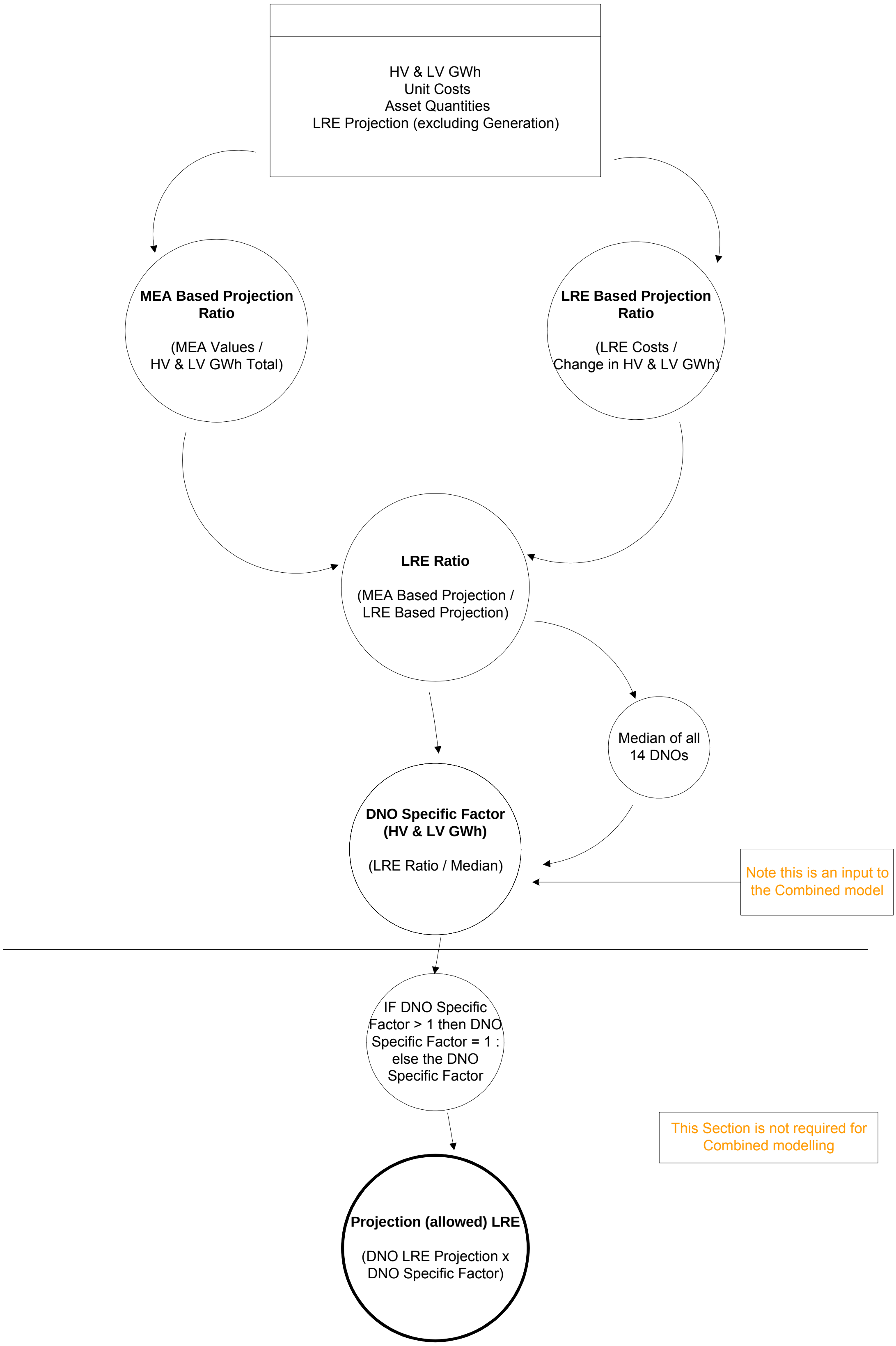
Although each DNO's network is comprised of a large number of smaller networks and that it would be expected that these would have a range of spare capacities depending on local load growth and when individual networks were last reinforced, it is possible that a larger number of the smaller networks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

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

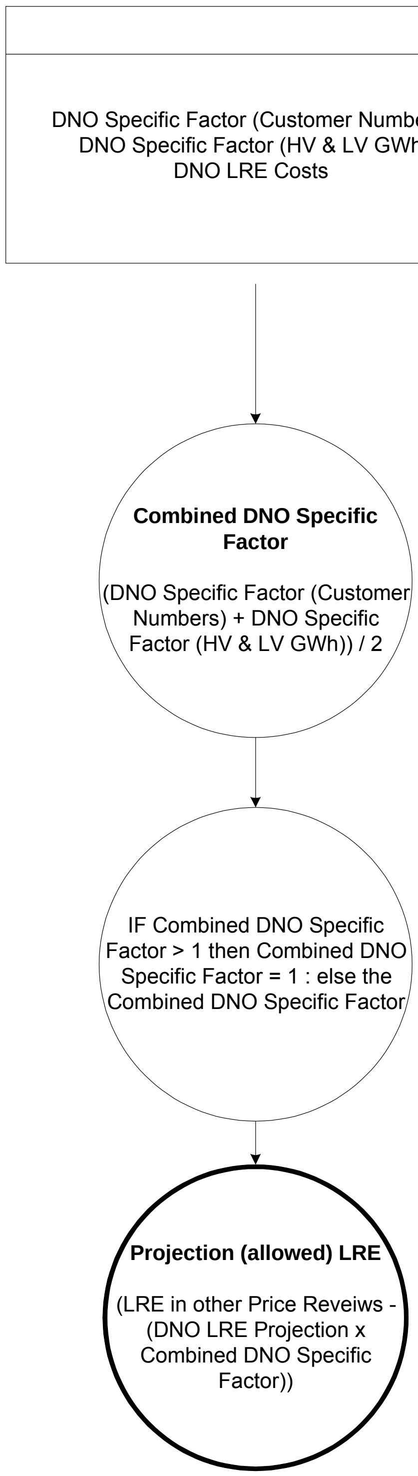
Combined Load Related Expenditure Modelling (Phase 1A Customer Numbers)



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



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



APPENDIX E

DEMAND GROWTH ANALYSIS

APPENDIX E - DEMAND GROWTH ANALYSIS

E.1.1 Introduction

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

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

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

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

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

E.1.2 Gross value added (GVA)

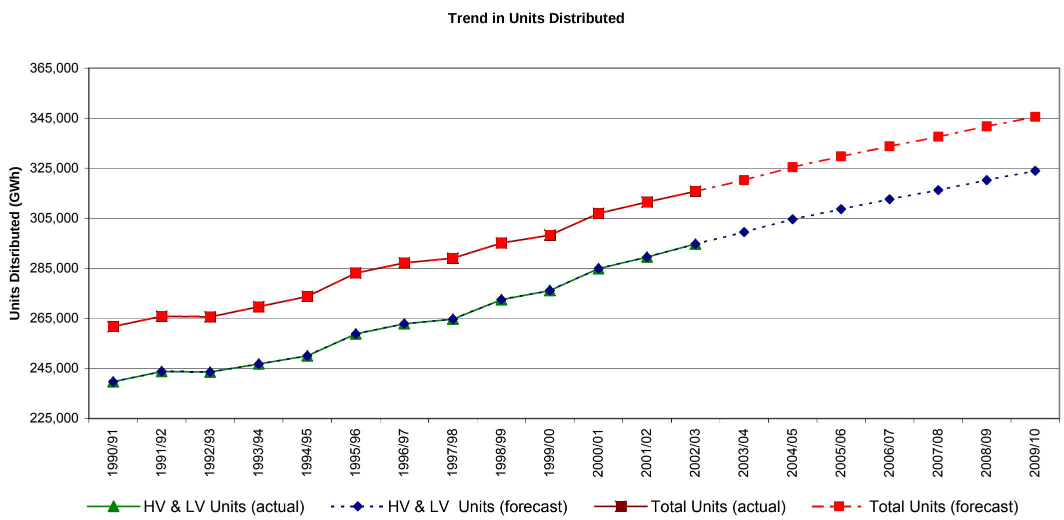
For the purposes of this review, GVA is treated as being synonymous with gross domestic product (GDP). Furthermore Regional Accounts are currently published in terms of GVA1 only. Statistics are published by geographical region in accordance with the Nomenclature of Units for Territorial Statistics (NUTS) classification. NUTS1 covers regions, NUTS2 covers sub-regions and NUTS3 covers unitary authorities or districts. At present NUTS2 data is available for the years 1995 to 2001 and NUTS3 data for 1993 to 1998 only.

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

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

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

Trend of energy distributed against time



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

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.

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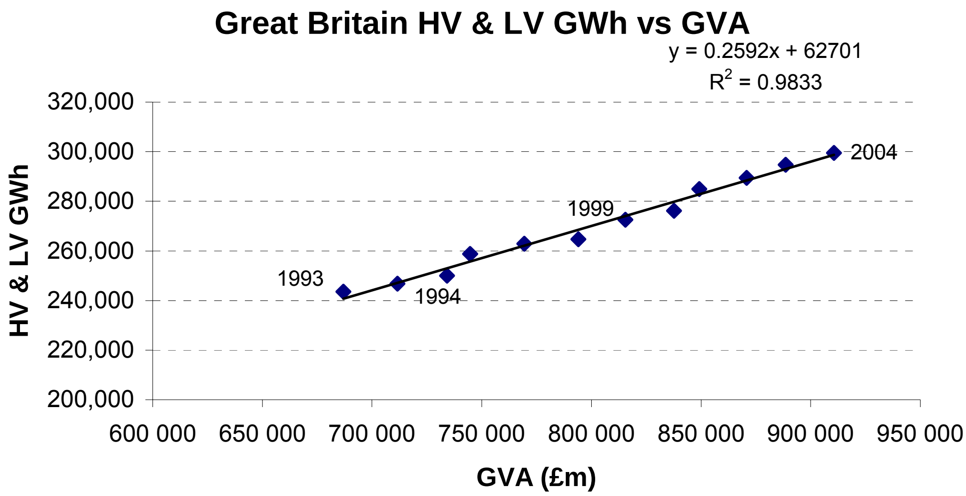
[1] Office of National Statistics: Local area and sub-regional gross domestic product, 26 April 2001, www.statistics.gov.uk

E.1.3 Historic trend of units distributed against GVA

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



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

E.1.4 GVA growth rates

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

For the years 2004/05 onwards, the HM Treasury "Forecasts for the UK Economy" dated February 20043 was used as the forecast for national growth. In a number of cases and, depending on the availability of published data, regional growth trends were estimated from the national trend but with a difference applied depending on the relative positions in 2003/2004.

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

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

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

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

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

E.1.5 Derivation of GVA-based load forecasts

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

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

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

APPENDIX F

NON-LOAD RELATED CAPEX MODELLING

APPENDIX F – NON-LOAD RELATED CAPEX MODELLING

F.1.1 NLRE asset replacement modelling for DPCR4

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

F.1.1.1 Age-based replacement

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

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

i. age profile

ii. retirement profile and

iii. unit cost.

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

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

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

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

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

F.1.1.2 Cyclic refurbishment / replacement

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

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

F.1.1.3 Assumptions

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

F.1.1.3.1 Overhead lines

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

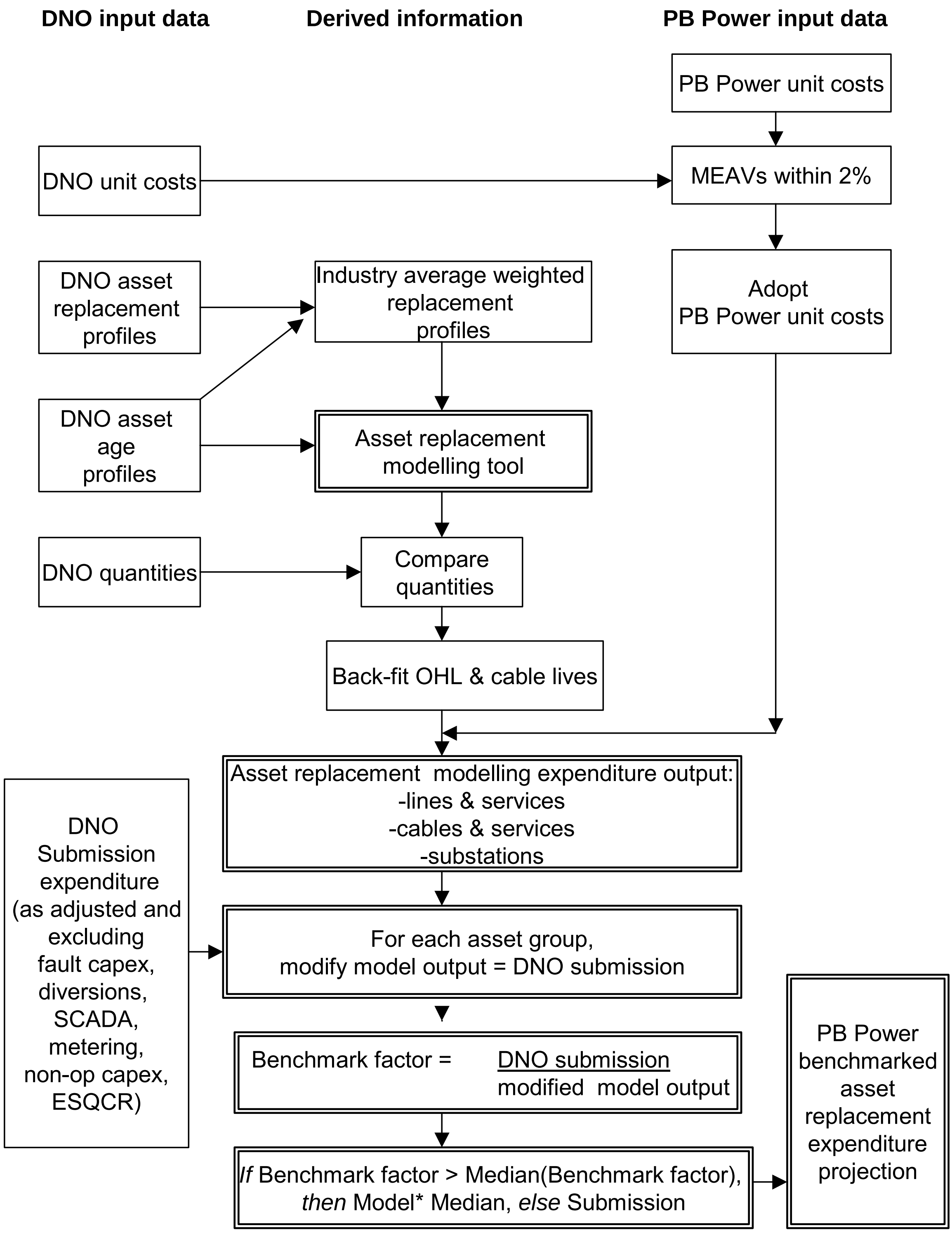
The model output is initially modified so that for each of the asset groups the overall industry (14 DNOs') expenditure predicted by the model is the same as that forecast by the DNOs. (The differences had in any case been small.) For each asset group, benchmark factors of DNO submission/model output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