Ofgem

DG-BPQ Analysis

Summary of Findings

Final Report

March 2004

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Glossary

CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
DG	Distributed Generation
DG-BPQ	Ofgem's Distributed Generation Business Plan Questionnaire
DNO	Distribution Network Operator
LDC	Line Drop Compensation
O&M	Operation and Maintenance

Summary

This report presents the key findings of our work on analysis of the distributed generation business plan questionnaire (DG-BPQ) returns provided by the distribution network operators (DNOs) in Great Britain and includes the findings from our visits to each of the DNOs to discuss their DG-BPQ returns. The focus of this report is on the quality of data provided in the DG-BPQs, the connection cost information provided, the forecasts for future penetration of distributed generation (DG), and the differences between the DNOs that may impact connection costs. The findings of this report will inform Ofgem's development of incentive mechanisms for DG.

The DG-BPQ returns have been completed by the DNOs to a generally high standard, although a number of minor inconsistencies have been discovered during the analysis of the data and the DNO visits, particularly between high-level and detailed information for the same projects included in the DG-BPQ tables for the historical and interim periods. However, the greater inconsistency in detailed project information is caused by the different approaches adopted by the DNOs in forecasting future DG and connection costs.

In the historical and interim periods, it is clear from the information provided that the policy of deep connection charging has led to self-selection of projects with little need for network reinforcement. However, the requirement for reinforcement is expected to increase considerably in the future period, particularly with a shallow connection charging regime which will potentially weaken the existing locational signal and lead to projects requiring more network reinforcement to proceed. Reinforcement is expected to be required on more projects in the future period but is also expected to increase in magnitude due to the need for more substantial thermal reinforcement. In this respect, the future period is unlikely to resemble the past and the connection costs from the historical period are therefore not likely to be representative of future connection costs.

Through review of the DG-BPQs and meetings with the DNOs, a number of differences in connection design policy were identified. Key examples of isolated practices with a potential cost impact include:

- use of redundant circuit breakers in series;
- not employing line drop compensation (LDC) to assist with voltage control;
- installing over-rated equipment capable of handling out-of-phase switching.

Streamlining practices in such areas could aid efficient capital investment. However, the cost impact of the practices observed is not expected to be significant in the scope of this analysis as they relate mainly to sole-use assets. Policies also vary considerably between DNOs for O&M costs, return on assets, loss adjustment factors, and reinforcement savings.

Forecasts of future DG penetration also vary considerably between DNOs. Those DNOs with a large number of enquiries have tended to rely on current activity to forecast activity for the future period. This includes SHEPD and SPD which are both experiencing considerable activity in onshore wind projects at present.

In contrast to DNOs with a high number of enquiries for connections, many others are experiencing little or no current activity in DG due to lack of renewable resource or favourable CHP sites. These DNOs have tended to adopt a more analytical approach to forecasting DG activity, considering a number of hypothetical scenarios and verifying these scenarios against external studies. In many

cases, DNOs have assumed that planning, commercial and regulatory frameworks will become more conducive to developments in future, particularly for combined heat and power (CHP) generation.

A national study on the costs of connecting DG performed by ILEX on behalf of the DNOs is referred to by a number of the DNOs and the presence of this study is considered valuable in providing a top-down approach to the industry as a whole and avoiding potential double-counting of capacity. Whilst the various approaches for forecasting DG activity and costs adopted by the DNOs may have individual inaccuracies, the resulting information is the best that is presently available in the industry.

Having taken account of the information presented by the DNOs together with external information sources and our own views we believe that the aggregated project volumes across all DNOs, while derived from a range of forecasting approaches, are probably the best estimate at this stage for planning the network investment needed at the national level. There is a range between minimum and maximum projections (9,800MW to 10,900MW) that appears representative of genuine uncertainty, and there are variations in individual accuracies and ranges between DNOS. Some DNOs forecast a wide range of possibilities without giving firm opinions on what they see as most likely outcome, which to some extent is reflective of genuine local uncertainties. Where possible, we have provided opinion on the robustness of the forecasting technique employed by each DNO and the reasonableness of the forecast volumes of DG in the future period.

Shared asset costs provided by the DNOs for individual projects in the future period are highly variable, driven largely by network capacity in the locality of the project. Whilst some trends were observed on the key cost drivers of project size, voltage, technology and reason for work, these were not strong enough for a bottom-up approach to modelling of costs to be feasible. Differences between the forecasting methods adopted by DNOs also reduce the usefulness of the data in a bottom-up analysis of costs.

Those DNOs with the highest forecast levels of future DG activity have proposed various levels of strategic reinforcement of their networks to accommodate the capacity wishing to connect. In the case of SPM no shared asset costs were shown in the high-level information as all shared asset costs had been merged with the substantial strategic reinforcement costs, which were not exclusively for connecting DG. However, in SHEPD the split of shared asset costs and strategic reinforcement was more towards shared assets, with some individual projects assigned very large costs for sub sea cable reinforcement where this work would in fact benefit multiple projects. Similar examples of high shared asset costs for individual projects appeared in UU's DG-BPQ return. Clearly, the different balance between shared asset costs and strategic reinforcement costs applied by DNOs further reinforces the unsuitability of the detailed project information for bottom-up analysis of costs.

The DNOs that have suggested a more strategic approach to reinforcement are SHEPD, SPD, SPM, and UU. Both SPD and SPM list significant strategic Capex in their DG-BPQs, and although SHEPD and UU list only a low value for strategic Capex they recognise that significant reinforcement costs might best be considered strategically rather than be allocated directly to particular projects that trigger incremental work. In our view these companies have provided clear and well-argued reasons why particular areas of their networks would require reinforcement under the forecast scenarios they have developed. We have also carried out a high level assessment of projected costs for strategic development proposals in each case and in general we believe them to be a reasonable estimate at this point in time, although for regulatory purpose not all these costs may be allocated to the DG category. In addition, SPD and SPM cost projections for DG strategic reinforcement originally appeared high relative to other DNOs. SPD's costs included those on its 132kV assets and, in SPM's case, the whole costs rather than the advancing costs for a reinforcement scheme were included. Appropriate adjustments have been made in the analysis to include only the relevant costs for these companies. Until proposals are developed in greater detail as project requirements firm up, the accuracies of cost estimates are likely to be fairly low, in our view around +/-20%, although this is based on overall feel rather than a detailed audit of individual costs, which is beyond the scope of this report.

From a top-down approach using regression analysis, the aggregated high-level information on overall shared cost estimates for the future period is seen to have an average unit cost of approximately £41k/MW, based on project-specific shared asset costs and non-project-specific strategic capex, indexed to 2005/06. A straight average of the high-level capacity and cost figures produces a unit cost of £42k/MW. Table S-1 summarises the expected levels of generation and high-level costs for each DNO. Whilst DNOs have adopted various approaches to forecasting levels of generation and future costs, it is our opinion that the aggregated high-level information is sufficiently robust for use in a top-down analysis of costs related to DG. Our opinion is based on the following:

- those DNOs with significant DG activity have generally based their forecasts of capacity on costs on actual enquiries;
- most other DNOs have referred to external projections in compiling their forecasts;
- whilst significant scatter in unit costs has been observed, no major discrepancies in costing methodologies were found during the course of work and the level of scatter is considered representative of the high dependence of unit costs on available network capacity in the location of projects.

In reviewing the spread of costs for different DNOs, we can find apparent reasons for the pattern that has emerged. However the uncertainties in the data do not allow us to form firm views. Given the uncertainty in the future costs, and the lack of detailed information in some DNOs, we believe that the most pragmatic approach is to take an overall average of the high level unit costs across all the DNOs as a reasonable view of the future DG cost. Exceptions could be made for DNOs who have justifiable and robust data. It is noteworthy that the costs are driven mainly by the existing network and the expected volume of renewable connections, and not by issues such as labour cost variations nationally. We would expect factors such as this to be relevant, but to be masked in the available data. In addition there may be scope for the application of new technology and techniques to reduce DG connection costs and this is being examined in separate work on the potential for Registered Power Zones (RPZ) and Innovation Funding Incentives (IFI) for DNOs.

There are good reasons to suggest that O&M costs have fallen in recent years. Introduction of IT systems have considerably reduced control costs and there have been significant improvements in the efficiency of fault location and repair. The general move towards maintenance based on plant condition monitoring rather than on a time based program has reduced maintenance costs and DNOs have made significant reductions in corporate overheads.

In our view there will be an increase in strategic Opex as a result of the increasing penetration of DG in the future period. Although the DNO thinking is not well developed on this and the figures they have put forward are clearly only rough estimates, our high level view is that some licensees may have over estimated and other licensees appear to have under estimated or overlooked cost increases in this area. The overall national total estimate for increase in strategic Opex due to DG may therefore be quite reasonable.

Regarding quality of supply we believe that DNOs should be able to make appropriate allowance for continued improvements in levels of CI and CML as DG penetration increases through good organisation with proper and timely planning.

DNOs have a range of approaches to DG projects wishing to connect to their networks, and this is evident even between individual DNOs facing similar levels of DG volumes and network constraints. These approaches range from resolving shared problems to facilitate connection leading to a positive relationship, to applying procedure rigidly, which tends to make the resolution of issues more difficult thus creating barriers. In our view there is room for improvement of information flow and flexibility of interaction between DNOs and developers.

Table S-1 – Summary of High-Level Costs for Future Period

	Capacity	Shared Asset Costs		Strategic	Total Cost	Unit Costs
		Newly Installed	Reinforced	Capex		
	(MW)	(£m)	(£m)	(£m)	(£m)	(£k/MW)
Aquila[1]	70 - 309	0.0	13.7 - 27.5	0.0	13.7 - 27.5	44.3 - 89.0
EME	865	0.2	10.5 - 49.6	1.2	11.9 - 51.0	13.7 - 58.9
EPN[2]	800	35.0	0.0	6.2	41.1	51.4
LPN	334	9.2	0.0	6.4	15.6	46.7
SPN[3]	471	12.0	0.0	5.6	17.6	37.3
WPD South West[4]	175 - 316	0.0	2.6 – 22.1	1.4	4.0 - 23.5	23.0 - 74.5
WPD South Wales[4]	261 - 455	0.0	3.9 – 31.9	1.9	5.8 - 33.8	22.2 - 74.3
NEDL	1153	0.0	9.5	0.0	9.5	8.2
YEDL	1097	0.0	11.3	0.0	11.3	10.3
SPD[5]	1437	1.7	3.5	14.3	19.5	13.6
SPM[6]	987	0.0	0.0	43.5	43.5	44.1
UU[7]	987 - 1530	5.5 – 28.9	20.1 - 36.0	2.2	27.8 - 67.1	28.2 - 43.9
SEPD	248	0.0	7.0 – 9.0	0.0	7 - 9	28.2 - 36.3
SHEPD	867	22.0 – 26.0	32.0 – 39.0	6.8	60.8 - 71.8	70.2 - 82.9
Totals[8]	**9752 – 10869**	**85.6 – 113.0**	**114.1 – 239.4**	**89.5**	**274.0 – 426.7**	

1. Aquila cost ranges relate only to the high capacity scenario of 309 MW.
2. Reinforced shared asset cost for EPN is included in newly installed shared asset cost. Capacity of 800 MW is taken from Table 11 of the DG-BPQ, which differs slightly from the figure of 807.8 MW in Table 10.
3. Reinforced shared asset cost for SPN included in newly installed shared asset cost.
4. The unit cost ranges shown relate to the minimum cost for the minimum capacity and the maximum cost of the maximum capacity in the WPD scenarios. Other combinations give slightly lower and higher unit costs respectively.
5. Table 11 of the SPD DG-BPQ refers to Table 13 (strategic costs) for shared asset costs for 1106 MW of the 1437 MW total forecast capacity. The initial costs submitted included some work on the 132kV system which is defined as transmission in Scotland. If these costs were included the SPD total strategic Capex would be £82.8m and the unit cost £61.2k/MW.
6. Table 11 of the SPM DG-BPQ refers to Table 13 (strategic costs) for all shared asset costs, which includes advancing a major investment scheme required for both demand and generation. If the whole scheme costs instead of only the advancing cost were included, then the total cost would become £81.1m and the unit cost £82.2k/MW.
7. The unit cost ranges shown relate to the minimum cost for the minimum capacity and the maximum cost of the maximum capacity in the UU scenarios. Other combinations give slightly lower and higher unit costs respectively.
8. Capacity figures are taken from Table 11. There is a difference of 10 MW between the total Table 11 figures and the total Table 10 figures due to minor rounding by EPN, LPN and SPN.

1 Introduction

1.1 Background

The UK Government's Energy White Paper sets out its long-term ambition for 60% reduction in the UK's carbon dioxide emissions by 2050. As part of the UK Climate Change Programme, the Government has also set a target for 10% of electricity supplied in the UK to be from renewables by 2010, and for there to be 10 GW of installed CHP by the same date. Both these targets are substantially in excess of current achievements. There is also an aspirational target of 20% of generation from renewables by 2020. The Scottish Executive has gone further and committed to a 40% renewable generation target for Scotland by 2020.

Whilst some large schemes, notably offshore wind projects, may be connected to the transmission network, much of this new capacity will be connected to distribution networks. In addition there is strong support in the Energy White Paper for micro CHP, and this will be connected to distribution networks at the low voltage level. These developments are a radical change from the recent past, and will require significant change in how distribution networks are planned and operated. The DTI has developed a roadmap setting out issues to be resolved in achieving this transition, and an OFGEM/DTI working group has considered the issues in some detail. The working group's recommendations have been taken up by the Distributed Generation Co-ordination Group (DGCG) for implementation.

There are currently perceptions that network connection issues are a significant barrier to the development of renewable and micro CHP projects. Each DNO is obliged to make connection offers to new generators applying for connection, and to make charges for network reinforcements required specifically to connect the new generation with the exception of connections under policy G83[1] which relates to small domestic generation projects. However, other "deep" reinforcements, which are not clearly attributable to single new connections, have to be managed within the DNO's capital budgets. In addition, the costs of the connections themselves can now be contested by project developers, who can engage contractors other than the DNO to perform certain aspects of the connection works. There is therefore relatively little incentive for the DNOs to connect DG. This situation has been recognised and Ofgem is in the process of designing appropriate incentives for DNOs to facilitate the connection and provision of network access to DG. The consortium of Mott MacDonald and British Power International (MM/BPI) has been appointed by Ofgem to analyse the historical and future cost drivers for connection of DG.

1.2 Purpose and Structure of Report

In order to gain an understanding of the level of costs to provide connections for distributed generators on an efficient basis, each DNO has been asked to submit data on historical and future DG connections, together with the costs and timescales for such connections. This report provides a summary and analysis of the information received from the GB DNOs in response to Ofgem's Distributed Generation Business Plan Questionnaire (DG-BPQ) issued on 27 June 2003. The analysis is supplemented by information received during visits to the DNOs undertaken during October and November 2003. Observations are made on the expected level of DG in each of the 14 licensed areas

[1] Engineering Recommendation G83/1 September 2003 "Recommendations for the connection of small-scale embedded generators (up to 16 A per phase) in parallel with public low-voltage distribution networks."

and on the quality of information provided. The key high-level figures provided in the DG-BPQs are summarised.

This report is broken into four main sections:

- DG-BPQ and DNO meetings summary;
- summary of DG activity and costs;
- key findings for each DNO; and
- assessment of DNO DG projections and costs.

The first section of the report summarises the qualitative evaluation of the information provided in the DG-BPQs and gained from the site visits and will:

- comment on the quality of data submitted and areas where more information/validation is needed;
- note differences in DNO practices for connection from examination of selected projects during the DNO visits.

The second section of the report will:

- summarise DG activity and the requirement for reinforcement;
- summarise the forecast for future DG activity;
- present a high-level summary of connection costs.

The third section of the report presents key findings for individual DNOs on volume and quality of data provided, forecast assumptions, policies for design and costs, and any particular issues.

The fourth section of the report sets out our assessment of the forecasts and explanations put forward by the DNOs in their DG-BPQs and associated narrative documents, together with commentaries on the results that have been derived in the course of this project. We also draw together our high level views on the approach of different DNOs and the key cost drivers in relevant areas of capital and operating expenditure.

It should be noted that the focus of this work is on shared costs, i.e. the costs inside distribution networks resulting from connection of generation, which is the topic of Ofgem's recent consultations on incentive mechanisms. Little attention is paid to sole-use asset costs as it is assumed that these will be paid by the generator for the foreseeable future.

As instructed by Ofgem, all costs are expressed in real terms for the financial year 2005/06, using the headline inflation rates before April 2003 as shown in Table 1-1 and an assumed headline inflation rate of 2.5% from April 2003 onwards.

Table 1-1 – Headline Inflation Rates

From	To	RPI
1997	1998	3.3%
1998	1999	3.1%
1999	2000	1.6%
2000	2001	3.0%
2001	2002	1.5%
2002	2003	2.2%
2003	Onwards	2.5%

2 DG-BPQ and DNO Meetings Summary

2.1 Overview

This section of the report discusses the data provided by the DNOs in the DG-BPQ returns and summarises DNO approaches and views in the following key areas, as described in the DG-BPQ returns and during the DNO visits:

- quality of DG-BPQ data;
- general trends;
- reasons for expenditure on shared assets;
- planning constraints;
- reinforcement savings;
- O&M costs;
- reasons for strategic expenditure; and
- losses.

2.1.1 Quality of DG-BPQ Data

The DG-BPQ returns have been completed by the DNOs to a generally high standard, although a number of minor inconsistencies have been discovered during the course of the DNO visits and analysis of the data. The most common of these inconsistencies is differences between high-level and detailed information for the same projects included in the DG-BPQ tables for the historical and interim periods. In the future period, a number of DNOs are not expecting large numbers of DG connections on their networks so have not been able to provide much meaningful information on connection costs. Other issues with the DG-BPQ data quality include missing information and seemingly incorrect reasons for work. Some of the inconsistencies discovered have been resolved with DNOs during the meetings or by subsequent communications.

The amount of information provided by the DNOs in the DG-BPQ returns and associated narratives generally follows the perceived importance of DG in their various networks. For example, UU expects up to 1500 MW of DG in the future period 2005 to 2010 and has undertaken a significant amount of work to understand the impacts of this level of generation on its network and business practices, including developing a detailed cost model. However, a potential issue is the selection by DNOs of projects to include in the detailed information tables, particularly for the future period. A number of DNOs have included only projects with a network impact, or have provided a selection of what they consider to be typical projects. This selection of projects by DNOs may impact the results of a detailed bottom-up analysis, which should ideally be performed on information for all projects, including those projects whose connections do not require work on shared assets in the network.

A number of areas in the DG-BPQ have been handled differently across the DNOs and these have been discussed during the visits to gain further clarification. Notable examples are loss adjustment factors, charging of O&M costs and inclusion of return and/or profit on the sole-use connection assets. These factors are discussed in the following sections along with other observations from the DG-BPQs.

2.1.2 General Trends

The DG-BPQ has been split into three periods: historical, interim and future. The historical period relates to DG commissioned between 1st April 2000 and 31 March 2003, the interim period covers DG scheduled to be connected to networks in the remainder of the present price control period from April 2003 to March 2005. The future period relates to the next price control period from April 2005 to March 2010.

The levels of DG needed to meet 2010 targets are significantly in excess of current connection applications and all DNOs are anticipating a step increase in connection applications in the future period. DNOs have generally based their forecast calculations on the assumption that the Government target for renewables will be met, but there is more uncertainty surrounding CHP. All DNOs report a lack of significant activity in CHP connections in the historical and interim periods, but have taken a range of approaches to forecasting the impact of CHP. Two DNOs include no CHP at all as no enquiries have been received to date (SPD and SPM), whilst two other DNOs include a significant amount of CHP on the assumption that the incentives for CHP will become more conducive and the Government's targets will be fully met (NEDL and YEDL).

Most DNOs have used relevant information from research bodies and Government offices to inform their forward views of likely DG connection volumes and associated costs. The DNOs in regions with greater potential resources for renewable generation have analysed the impact on the network in greater detail to identify key strategic opportunities and constraints. They reported the need for significant strategic development of their network during the next price control period to enable Government targets to be met.

In general, DNOs are pessimistic regarding CHP. Those projects included in DG-BPQ responses arise mainly from assumptions regarding partial achievement of the Government target rather than projects, and from further assumptions regarding micro generation. We concur with this pessimism and suggest that the industry has little incentive to consider CHP given current and predicted spark spread (difference between electricity price and cost of fuel) and the uncertainty regarding carbon emissions pricing.

2.1.3 Reasons for Expenditure on Shared Assets

In the DG-BPQ returns DNOs listed reasons for expenditure on the installation of shared assets to facilitate DG connections in the historical, interim and future periods on a project-specific basis in the following categories:

- fault level capacity;
- voltage limits;
- system stability;
- thermal capacity;
- other reasons.

One DNO listed expenditure in more than one category for some projects. In all 120 instances of expenditure on shared assets in the above categories were listed by DNOs. 19 of these were in the historical period, 16 in the interim period, and 85 in the future period. From the data given by DNOs it was possible to identify two further significant reasons for expenditure on shared assets, which were:

- protection equipment;
- upgrading of power lines to three phases (three-phasing).

There were no instances listed of expenditure purely for system stability with the exception of one DNO who recorded an instance of expenditure on protection in this category.

Table 2-1 provides a breakdown of instances of expenditure on shared assets in each category together with a percentage of the projects for the relevant period:

Table 2-1 – Reasons for Shared Assets

	Historical		Interim		Future	
	Number	%	Number	%	Number	%
Fault Level	7	37%	6	38%	18	21%
Thermal	1	5%	5	31%	42	49%
Voltage	3	16%	4	25%	20	24%
Protection	1	5%	1	6%	4	5%
Three-Phasing	3	16%	0	0%	0	0%
Other	4	21%	0	0%	1	1%
Totals	19	100%	16	100%	85	100%

The low number of projects listed in the historical and interim periods together with a wide variation in the circumstances surrounding particular projects makes it difficult to draw reliable conclusions from this information. However, the apparent trend towards a higher proportion of expenditure on network thermal capacity seems reasonable in view of the increasing number of generators likely to be connected in future particularly in remote locations. The lower proportion of projects in the future period requiring fault level related expenditure may reflect a reduction in the proportion of urban DG connections in particular CHP where DNOs do not in general expect national targets to be achieved. However, analysis of projects requiring reinforcement due to fault level indicates an increase in unit costs in moving from the historical and interim periods to the future period, reflecting reducing levels of fault level headroom on the networks as installed capacity increases, which is consistent with our expectations.

The following bullet points set out some typical examples of engineering work listed by DNOs under the relevant categories of shared asset cause:

Fault level:

- replacing circuit breakers;
- replacing distribution ring main units;
- replacing transformers;
- replacing isolators.

Thermal Capacity:

- upgrading cables and overhead lines;
- replacing transformers;
- provision and extension of substations and switchboards;

- replacing circuit breakers.

Voltage Control:

- provision of voltage regulators;
- provision of shunt reactors;
- provision of transformer and reactor tap changers.

Protection:

- provision and upgrading of automatic control equipment to detect network fault conditions and provide for safe power interruption by relevant circuit breakers.

Three-phasing:

- upgrading of single-phase lines typically in remote rural areas to provide for the connection of three-phase generators.

Other:

- upgrading of circuit breakers to accommodate out-of-phase switching;
- construction of new substations and switchboards where the DG forms part of wider strategic reinforcement work in an area;
- network reconfiguration so as to provide for security of supplies following DG connection.

2.1.4 Planning Constraints

Planning permission is a key issue for the growth of DG, being central to the development of generation projects and also the construction of new sections of transmission and distribution network. Most DNOs report no signs that planning is becoming easier, with the exception of Scotland where considerable progress has been made in approving renewable projects, particularly onshore wind farms. For the electrical interconnection, most developers of DG appear to favour the more costly underground cables rather than overhead lines due to the greater certainty of timely planning consent. Exceptions exist in Cumbria and the north of Scotland where close liaison between the DNO and the Planning Authority has streamlined the process for approval of both the generation site and the associated electrical connection works.

2.1.5 Reinforcement Savings

All DNOs give credit to DG where there is a coincidence between reinforcement already planned and the requirement for a DG connection. However the planning window allowed is in some cases too short for significant savings to be realised in practice. Some DNOs only credit savings where planned reinforcements have already been approved for construction.

Policies vary on giving credit for assets reclaimed as a result of connection work, depending on whether the DNO employs a time-based or remaining life-based replacement strategy. DNOs are generally wary of re-using assets that are replaced ahead of schedule given the risk of failure following relocation to a new site, particularly transformers.

Only NEDL and YEDL list any estimated savings for work avoided on shared assets in the future period.

2.1.6 O&M Costs

Unlike load customers, DG customers do not currently pay ongoing Use of System charges to DNOs. The contribution from a DG customer to the overall DNO O&M cost is collected, usually as a one-off payment, as a component of the DG connection charge. This payment effectively covers ongoing provision of the DG network connection including contributions to network maintenance, control room operations, and emergency restoration of the network following fault conditions together with a contribution towards the general overheads of running the DNO Company.

In addition to O&M charges some DNOs also include an additional percentage rate of return in the DG connection charge, on the basis that much of the connection work is open to competitive quotation. However, most DNOs do not track actual outturn costs so the actual return earned is not known. This is an area that would need improved clarity in future, particularly as part of Ofgem's proposed incentive mechanism for shared asset costs under a shallow connection charging policy.

Table 2-2 shows the range of O&M costs charged by the DNOs for the three periods covered by the DG-BPQ returns, expressed as either a one-off charge determined as percentage of the direct costs of connection, or as an annual charge where noted. The figures vary considerably as can be seen from the table.

Table 2-2 – O&M Charges as Percentage of Direct Costs

	Historical	Interim	Future
Aquila	22[1]	22[1]	22[1]
EME	12 to 27	8 to 25	35
EPN	10 to 22.5[1]	22.5	10 to 20
LPN	0[2]	0[3]	10 to 20
SPN	28	25	25
WPD South West	14.3 to 23	9 to 18	SS[4]
WPD South Wales	16 to 21	15 to 19	SS[4]
NEDL	0.98pa[5]	0.98pa[5]	0.98pa[5]
YEDL	9-37	25	0.98pa[5]
SPD	19 to 33	25 to 33	2.25pa[5]
SPM	14 to 25	14 to 20	2.25pa[5]
UU	14 to 30	14	14
SEPD	0[6]	20	20
SHEPD	25	20 to 25	20

1. Figure adjusted from DNO DG-BPQ expressed as percentage of connection charge.
2. Only two projects required asset installation in LPN historical period.
3. No projects requiring asset installation in LPN interim period.
4. Site specific rate will be calculated – likely to be less than the WPD current standard of 19%.
5. Percentage rate applicable per annum would be capitalised at 6.5% at customer request.
6. SEPD covered O&M cost during the historical period through the application of an annual charge.

With regard to O&M on shared assets, most DNOs apply the same percentage as used on sole-use assets, with some making a distinction between newly installed shared assets and replaced shared assets and only charging O&M on newly installed assets. Some companies do not recover O&M costs at all on the shared assets component of DG connection costs. Most companies also offer site-specific arrangements to cover O&M costs for larger projects. Table 2-3 shows a summary by DNO of policy on the application of O&M charges to the shared use component of DG connection costs.

Table 2-3 – O&M Policy for Shared Assets

DNO	Standard O&M Charging Policy
Aquila	Same percentage applied to sole-use and shared assets[1]
EME	Same percentage applied to sole-use and shared assets
EPN	Same percentage applied to sole-use and shared assets
LPN	Same percentage applied to sole-use and shared assets[2]
SPN	No O&M applied to shared assets
WPD South West	Same percentage applied to sole-use and shared assets in the historical and interim periods. In the future period no O&M will be charged on shared assets as WPD anticipates that these will not be chargeable directly to the customer under future connection charging rules.
WPD South Wales	As for WPD South West.
NEDL	Same percentage applied to sole-use and shared assets[1]
YEDL	Same percentage applied to sole-use and shared assets[1]
SPD	O&M is calculated on an individual basis, and is only charged on shared assets where equipment requiring additional maintenance is installed and connection charges to the customer are applicable.
SPM	As for SPD.
UU	Same percentage applied to sole-use and shared assets
SEPD	Same percentage applied to sole-use and shared assets
SHEPD	Same percentage applied to sole-use and shared assets

1. O&M is only charged where new assets are installed but is not applied to replaced or reinforced assets.
2. Although this is LPN policy there have been no projects to date where this has been applicable.

We comment further on O&M policies in section 5.4.

2.1.7 Reasons for Strategic Expenditure

In the DG-BPQ returns DNOs were asked to list strategic DG-related expenditure in the historical, interim, and future periods broken down into the following categories:

- general infrastructure;
- research and development;
- planning and design;
- operational and control room;
- other reasons.

DNOs were further asked to divide expenditure in these categories between operational expenditure (opex) and capital expenditure (capex).

General infrastructure strategic capex on the network to accommodate DG generally becomes necessary where DG capacity and fault levels at particular locations rise gradually over a period of time triggering switchgear changes, or the necessity for extra equipment to facilitate active network management. This can arise as a result of periodic reassessments by the DNO or it may become apparent on consideration of a particular DG project to which it would be unfair to allocate the full upgrading costs.

In addition DNOs have included differing levels of strategic capex according to the level of DG activity expected. Some DNOs have anticipated a more strategic approach to DG whereby agreed shared-asset network reinforcements would be undertaken in particular areas in anticipation of DG connections. These DNO areas are generally those in which there is significant wind energy potential. Other DNOs with less renewable energy resource have anticipated continuing on the present incremental approach with network reinforcement defined by the requirements of individual projects. We comment further on the strategic reinforcement proposals of the DNOs in section 5.2.

Table 2-4 shows the breakdown of strategic capital and operational costs listed by the DNOs for the relevant expenditure periods, presented as total costs for each of the different periods:

Table 2-4 – Summary of Strategic Capex and Opex

	Capex (£m)			Opex (£m)		
	Historical	**Interim**	**Future**	**Historical**	**Interim**	**Future**
Aquila	0.00	0.00	0.00	0.00	0.00	0.10
EME	0.00	0.00	1.16	0.61	0.94	1.75
EPN	2.43	2.24	6.15	0.38	0.71	7.47
LPN	0.13	0.58	6.43	0.09	0.14	0.90
SPN	2.42	2.20	5.59	0.28	0.19	2.33
WPD South West	0.00	0.00	1.43	0.14	0.09	0.25
WPD South Wales	0.00	0.00	1.90	0.15	0.10	0.27
NEDL	0.00	0.00	0.00	0.04	0.22	6.53
YEDL	0.00	0.00	0.00	0.18	0.22	6.33
SPD	0.00	0.00	14.27[1]	0.16	0.10	0.68[1]
SPM	0.00	0.00	43.53[1]	0.16	0.10	0.68[1]
UU	0.13	0.90	2.24	0.48	0.37	5.13
SEPD	0.00	0.00	0.00	0.00	0.00	0.00
SHEPD	0.00	2.26	6.83[2]	0.03	0.00	0.33

1. SPD and SPM strategic capex figures given as real 2003/04 so indexed to 2005/06. SPD's initial costs included those to be incurred on the 132kV system which is defined as transmission in Scotland. SPD's strategic Capex would be £82.81m if the 132kV costs were included. SPM's strategic capex would be £81.11m if the whole scheme costs instead of only the advancing cost of a strategic investment scheme required for both demand and DG were included. Strategic Opex figures for SPD and SPM, as originally submitted, would total £8.96m and £8.80m respectively as they would include an element of 10% of the original Strategic Capex (i.e. the £81.11m and £82.81m).

2. Period for SHEPD's future strategic capex given as 2006 to 2008 therefore used 2007 for indexing.

2.1.8 Losses

DNOs agree that allocation of overall loss factors to DG is a difficult problem. Some provide no values, some simply quote the factors generally used in Settlements, and others calculate specifically for each project. Losses may increase locally to the generator but may reduce at higher voltages in the network and may vary significantly with season and time of day.

2.2 Examination of Selected DG Connection Projects

A selection of projects from the historical and interim period data were examined during the DNO visits to improve understanding of the connection process and the various policies for equipment design and connection charges. In most examples the connection projects examined were designed to minimum cost in each particular situation. However, there were a number of inconsistencies identified during the visits that have the effect of introducing extra connection costs for both capital and O&M for generators in some DNO areas. Key examples include:

- circuit breakers in series;
- use of line drop compensation (LDC);
- out-of-phase switching.

In addition there was evidence that some opportunities to share costs, and thereby improve supplies to existing customers, are being lost and this may increase with the move towards a shallower connection charge policy. These points are discussed further in the following sections.

2.2.1 Circuit Breakers in Series

One DNO requires the DG metering circuit breaker to be connected via a short length of cable to a customer's main circuit breaker so that faults on the customer's system do not operate the metering circuit breaker. The short cable must have unit protection. This DNO does not accept jointly owned switchboards consisting of an incoming metering circuit breaker with a customer's busbar and feeder circuit breakers although it was stated that this latter policy may change in future.

In its design approach this DNO appears to rely rigidly on written policies and design standards, which often imply the need to install several circuit breakers where most DNOs would manage with fewer. This rigid adherence to standard systems has no doubt reduced training costs in the past but is now causing additional costs to generation connections. The standards used by this DNO seem to be out of line with general DNO practice.

A second DNO does not permit the operation of its circuit breakers from customers' protection equipment. This results in the need to install an extra circuit breaker on the customer side of the metering circuit breaker adding about £12k to the connection cost of an 11kV project for example. Other DNOs permit customer's protection equipment to operate the DNOs' circuit breakers.

2.2.2 Line Drop Compensation

Two of the schemes checked in one DNO involved 2 MW generation connections to 11 kV systems. In both cases, several kilometres of 11kV cable were laid to connect at a point close to the 33/11 kV substation. The reason given was that the DNO operates tap-changers to give a flat 11.5 kV on the rural systems. Any generation connection to the network at a distance from the 33/11 kV substation will therefore be liable to cause an over-voltage at light system load.

If LDC were installed, as it is in other DNOs, the voltage would be reduced at light load permitting generation to be connected further from the 33/11 kV substation. Thus some or possibly all the 11 kV cable would then be unnecessary.

The DNO would incur hardware and training costs to apply LDC but these would most likely be recovered in savings in 11kV network costs for distribution customers. LDC would allow networks to operate with higher voltage drop without causing unsatisfactory voltages to customers. It is in use by most, if not all, other DNOs.

2.2.3 Out-of-Phase Switching

One DNO insists that its circuit breakers are rated to withstand out-of-phase switching of the generator. Although this would not be done intentionally, in the worst case an operator could mistakenly close onto a generator 180 degrees out of phase thereby exceeding the normal fault rating of the switch and possibly incurring injury as a result. For health and safety reasons this DNO therefore requires replacement of switchgear not meeting the out of phase switching rating which leads to extra connection costs being incurred by the generator in some cases. If this practice were deemed to be necessary across all DNOs it would introduce extra costs of connection. In our view the installation of check-synch interlocks would provide a lower cost solution to this problem although it may not be possible to do this in every case.

2.2.4 Missed Opportunities to Share Costs

In one DNO a small generator was to be connected at a point where the only 11kV available was a single-phase overhead line of small cross section to a remote transformer. To rebuild this would have incurred planning delays and as the generator was prepared to pay for underground cable, this was laid to a point near the 33/11kV substation. Although this is a satisfactory solution for the DNO and the generator, it raises points in respect of the current studies.

If the existing customer connections to the overhead system were transferred to the new underground cable (subject to satisfactory voltage), their reliability of supply might be expected to improve and a substantial length of overhead line could be dismantled. The point of common coupling would then have been at the nearest customer's transformer and the bulk of the cable would therefore have become "shared assets".

Under a shallow charging system, there would be an incentive for DNOs to avoid connecting existing customers to a new network installed for a generator connection. This would keep the point of common coupling as far as possible upstream in the network and at the highest practical voltage as much of the cost would then be sole-use and directly chargeable to the generator rather than shared cost funded by the DNO.

3 Summary of DG Activity and Costs

Table 3-1 presents a summary of the high level information provided in the DG-BPQs on the number of projects, capacity and costs for DG in the historical, interim and future periods. Total installed capacity in the historical period was 2104 MW, including two CCGT projects totalling 820 MW in the networks of EPN and SPN that connected at distribution voltage. For the analysis of costs, these projects have been excluded as they are considered unrepresentative of the general spread of DG projects in the period. In the interim period, DNOs expect to connect 1027 MW of generation, whilst the future period is expected to result in around 11000 MW of new generation, a dramatic step change from present levels.

Figure 3-1 shows the breakdown of generation capacity in the historical and interim periods by technology types. Despite the UK's relatively slow start in the wind industry compared to other European countries, onshore wind is still the largest type of generation technology connected to the distribution network in the historical and interim period. CHP is the next largest contribution.

Figures 2-2 and 2-3 present the maximum and minimum forecast technology mix for the future period. The difference between the maximum and minimum scenarios is not large as only a small number of DNOs provided a range of future capacity, most providing point estimates. From the figures it is clear that onshore wind will continue to be the largest contribution. CHP remains the second largest technology but much of this is based on the expectation of more favourable conditions in the future period. Offshore wind is the third largest contribution with projects being developed under Crown Estate licensing arrangements. Marine technologies such as wave and tidal projects are expected to develop during the future period but are forecast to make only a minimal contribution to the generation mix, according to the DG-BPQs.

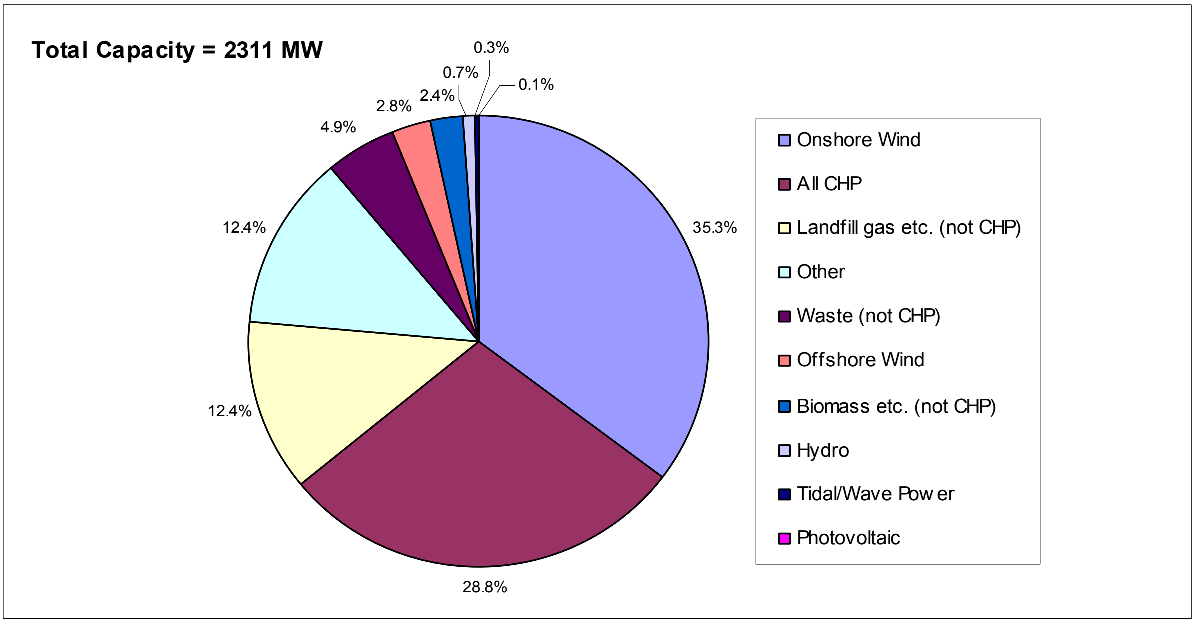

Figure 3-1 – Technology Share in Historical and Interim Periods

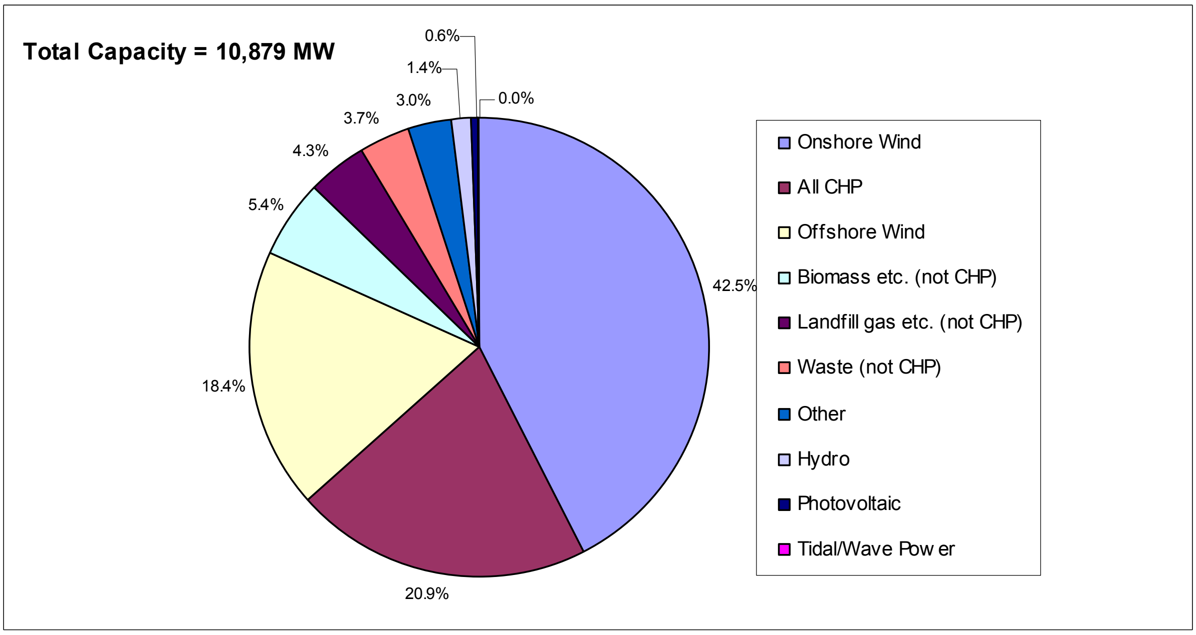

Figure 3-2 – Technology Share in Future Period – Maximum Scenario

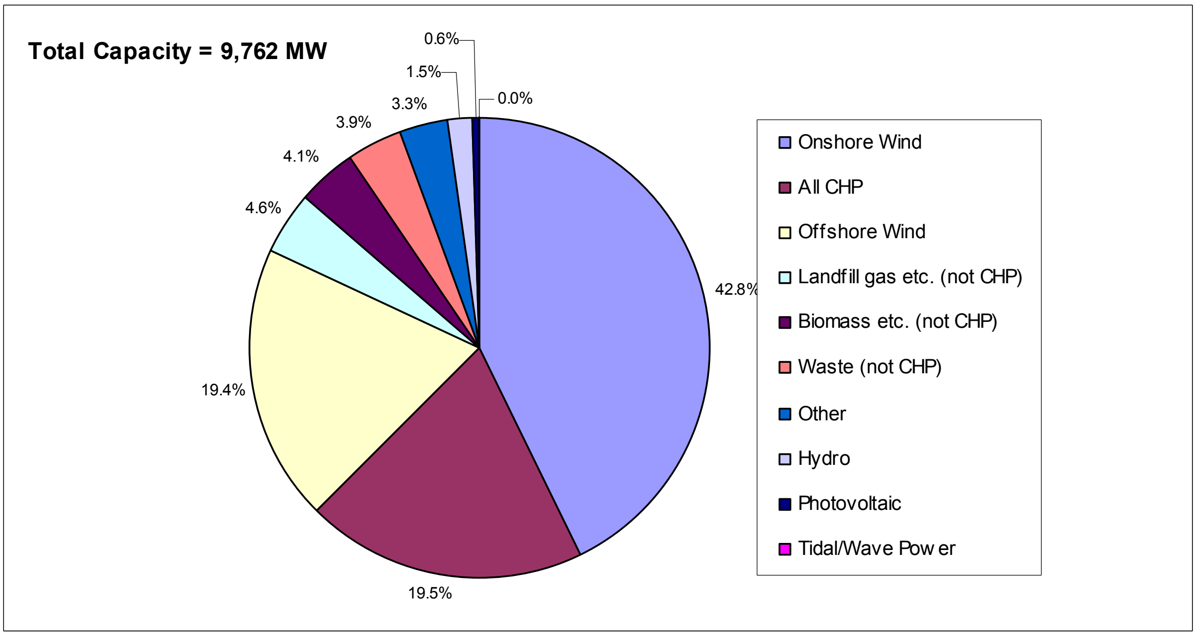

Figure 3-3 – Technology Share in Future Period – Minimum Scenario

Table 3-1 – High Level Information on DG

	Aquila	EME	EPN	LPN	SPN	WPDSW	WPDSWa	NEDL	YEDL	SPD	SPM	UU	SEPD	SHEPD
Historical[1]														
Number of Projects	39.0	22.0	77.0	88.0	28.0	41.0	45.0	21.0	31.0	8.0	14.0	36.0	9.0	17.0
Total MW Connected	93.5	67.3	502.2	101.5	541.5	46.7	70.9	52.7	211.4	76.8	111.8	122.7	51.1	80.5
Sole-Use Capex (£m)	1.0	1.3	1.6	0.0	5.8	0.7	1.9	0.5	8.8	2.7	4.6	1.9	2.5	3.2
Shared Capex (£m)	4.2	0.0	18.7	0.0	4.1	0.0	0.0	0.8	0.9	0.5	2.1	2.9	0.0	0.2
Strategic Capex (£m)	0.0	0.0	2.4	0.1	2.4	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
Interim[1]														
Number of Projects	12.0	5.0	25.0	18.0	7.0	22.0	22.0	7.0	1.0	6.0	8.0	6.0	20.0	18.0
Total MW Connected	19.5	22.6	43.5	4.9	15.0	37.5	134.7	5.6	6.0	84.1	173.1	59.3	128.5	293.1
Sole-Use Capex (£m)	0.6	0.6	1.8	0.0	0.9	2.5	5.3	0.1	1.1	2.7	8.1	7.0	7.0	7.4
Shared Capex (£m)	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	1.7	0.9	0.0	0.9	1.6
Strategic Capex (£m)	0.0	0.0	2.2	0.6	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.0	2.3
Future														
Number of Projects – min[2]	33.0					16.0	25.0					118.0		
Number of Project - max[2]	91.0	91.0	24.0	25.0	10.0	24.0	44.0	532.0	572.0	73.0	35.0	310.0	15.0	84.0
Total MW Connected - min	69.7					175.0	261.4					987.0		
Total MW Connected - max	309.0	865.0	807.8	335.4	472.0	315.8	455.0	1152.9	1097.4	1437.0	987.0	1530.0	248.0	866.7
Sole Use Capex £m - min	1.5	15.9				2.9	1.5					27.6	8.0	33.0
Sole Use Capex £m - max	8.2	38.6	35.9	5.7	21.0	19.1	21.1	74.2	62.9	153.5	26.5	55.5	10.0	40.0
Shared Capex £m - min	13.7	10.7				2.6	3.9					25.6	7.0	54.0
Shared Capex £m - min	27.5	49.6	35.0	9.2	12.0	22.1	31.9	9.5	11.3	5.2	0.0	64.9	9.0	65.0
Strategic Capex (£m)	0.0	1.2	6.2	6.4	5.6	1.4	1.9	0.0	0.0	14.3[3]	43.5[4]	2.2	0.0	6.8

1. Historical and interim costs have been indexed to 2005/06. No date information is available in the high-level information so it has been assumed that all historical period costs occurred in 2001/02 and that all interim period costs occurred in 2004/05. Costs in the future period are nominal.
2. Number of projects excludes photovoltaics and micro CHP due to some very high numbers of small projects, but capacity of these projects is included in the table.
3. This excludes costs on the 132kV system which is defined as transmission in Scotland.
4. This would be 81.1 if the whole scheme costs instead of only the advancing cost of a strategic investment scheme required for both demand and DG were included.

3.1 Forecasts for Future DG Activity

Where possible, DNOs have used actual enquiries to construct the forecasts of future DG activity. Areas of particular interest for renewable projects are Scotland and the west coast of England, notably in the networks of SSE Hydro, SPD, SPM, and UU. Most DNOs have also taken into account external projections (OXERA, DTI and relevant Government Offices etc) where applicable for their geographic area in arriving at their estimates of likely future connected capacity of DG. In addition a number have used the model developed on their behalf by ILEX to estimate the likely costs of connection of distributed generators moving forwards. This model is based on a generic treatment of the network in each DNO area and as such has not taken into account the possible effects of clustering of distributed generators at particular locations.

The results of the ILEX study, whilst providing a useful indicator of likely costs, need to be treated with caution. A large number of simplifying assumptions have been made in undertaking the work. In addition it was not a detailed system study based on particular networks but a modeling approach using stylised, average and generic structures to describe networks. DNOs commented that the modeling did not fully appear to have captured the scale of the impact of expected DG development. As a result DNOs found it necessary to amend some of the ILEX results to take account of their views of likely development in particular areas before finalising the DG-BPQ returns. However, the ILEX study at least provides a broad-brush top-down view of DG on an industry basis. Most DNOs emphasise that there is the potential for outturn costs to differ significantly from the estimates they have provided.

An alternative approach has been adopted in one DNO area in which a number of scenarios have been set out and likely costs studied through the assessment of pseudo connections that might be required in particular areas of the network. This approach appears more likely to give a better account of the effect on cost projections of likely clustering of DG. However, the model needs to be fine tuned to closely fit the specific DG projects.

Our high level assessments of the DNO forecasts of future DG volumes are set out in section 5.1.

3.2 Costs of Connection

Across the range of historical and interim DG-BPQ returns from DNOs there are comparatively few projects with shared asset capital costs, the majority having sole-use asset costs only. Furthermore, there are only a handful of projects requiring the sort of deep reinforcement anticipated in future, and those that have been carried out are for single large generators (e.g. CCGT) rather than to facilitate multiple connections of smaller generators. A number of DNOs have highlighted that projects requiring significant shared costs have not proceeded in the historical and interim periods due to the deep connection charging policy making connection uneconomic for small generators. Such projects are therefore not evident in the DG-BPQ data. For this reason the shared cost in £k/MW averaged across all DNOs and all connected capacity in these periods might be expected to be less than the figure that would become evident moving forward under an alternative shallower connection charging policy.

There are some variations across the DNOs in the interpretation of what constitutes sole-use assets and what constitutes shared-use assets, which may result from the fact that generators are currently charged for the full cost of connection thus making it unnecessary to focus clearly on the precise definition of sole/shared assets.

The key reasons for shared costs in the historical and interim periods are mainly fault level, voltage control and, to a lesser extent, thermal requirements. However, this relates mainly to projects that have been accommodated on existing networks with judicious replacement of local switchgear to avoid fault levels being exceeded but without the need for deep reinforcement. Moving forward it appears likely that thermal requirements will become more dominant as larger strategic reinforcements of the network become necessary in some areas to accommodate increased export from DG.

Figure 3-4 shows total shared asset costs of all projects within the historical and interim periods for which detailed information was provided, ignoring the proportion charged to the generator. Two CCGT projects of 400 MW and 420 MW connected to the networks of SPN and EPN respectively have been omitted from the analysis as they are considered unrepresentative of future DG activity.

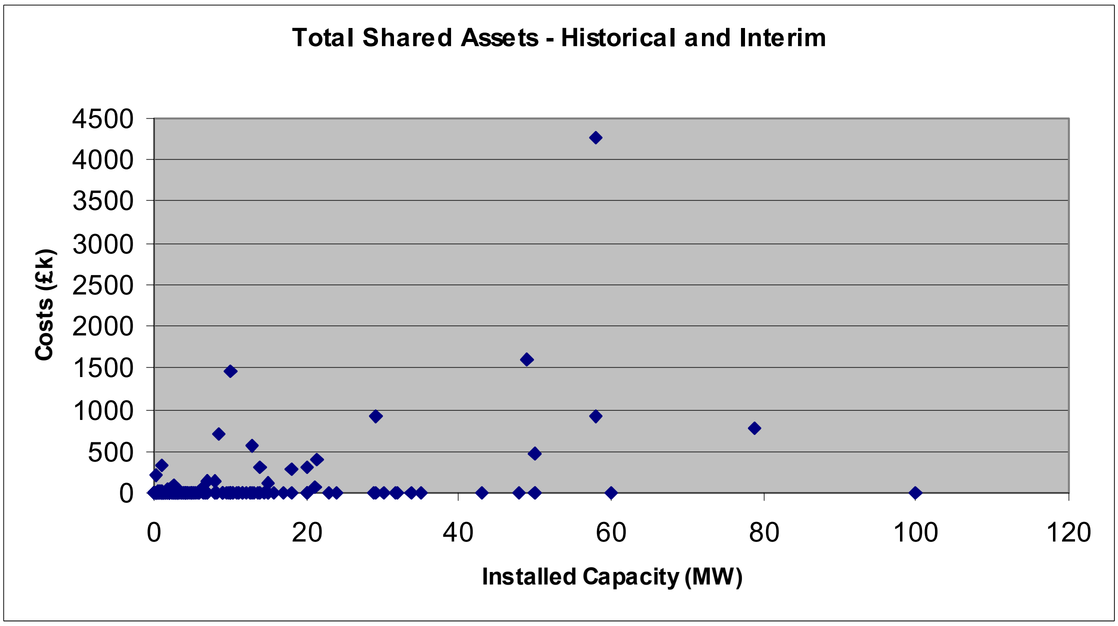

Figure 3-4 – Total Shared Assets Costs for Historical and Interim Periods

As can be seen from Figure 3-4, there is wide variation in the costs of connections, with many projects having no shared costs. In total there are 457 projects for which information was provided in the historical and interim periods, and only 37 (or 8%) of these projects have shared assets. The projects that have shared assets represent 22% of the total installed capacity of the 457 projects, which suggests that it is the larger projects that generally trigger reinforcement. However, this cannot be easily observed in the scatter of costs in Figure 3-4.

Figure 3-5 shows total shared asset costs for all projects within the future period for which detailed information was provided.

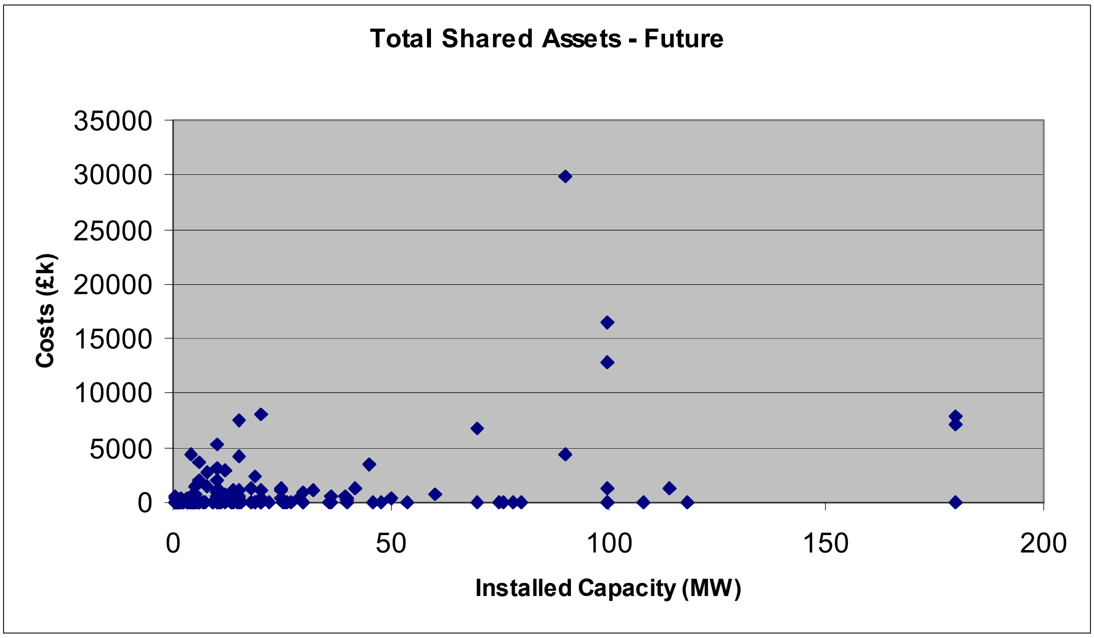

Figure 3-5 – Total Shared Assets Costs for Future Period

As can be seen from Figure 3-5, there are a larger proportion of projects with shared assets in the future period: 79 out of 205 projects, or 39%.

By installed capacity, the projects with shared assets represent 47% of the total installed capacity, again suggesting that it is the larger projects that trigger reinforcement. However, as with Figure 3-4, this trend is not easily confirmed by observation.

DNOs differ in the levels of anticipated strategic spend in the future period. The DNOs listing significant strategic infrastructure costs in their DG-BPQ returns comment that the need arises over a period of time where the general increase in fault levels triggers switchgear replacement and it would be unfair to charge this to a specific project. It is difficult to differentiate strategic costs due to general load growth and to growth in DG but both will be a factor.

It is apparent from Figures 2-4 and 2-5 that there are no obvious high-level correlations for costs of shared assets from the detailed project information provided.

The high-level information provided by the DNOs on shared assets costs and strategic capex is presented graphically in Figure 3-6 against expected installed DG capacity. Where a DNO has provided a range of capacity and cost figures, a minimum and maximum unit cost has been included in the figure. To provide equal weighting to each DNO in the analysis, where single point estimates for capacity and cost have been provided by a DNO, these have been included in the figure twice.

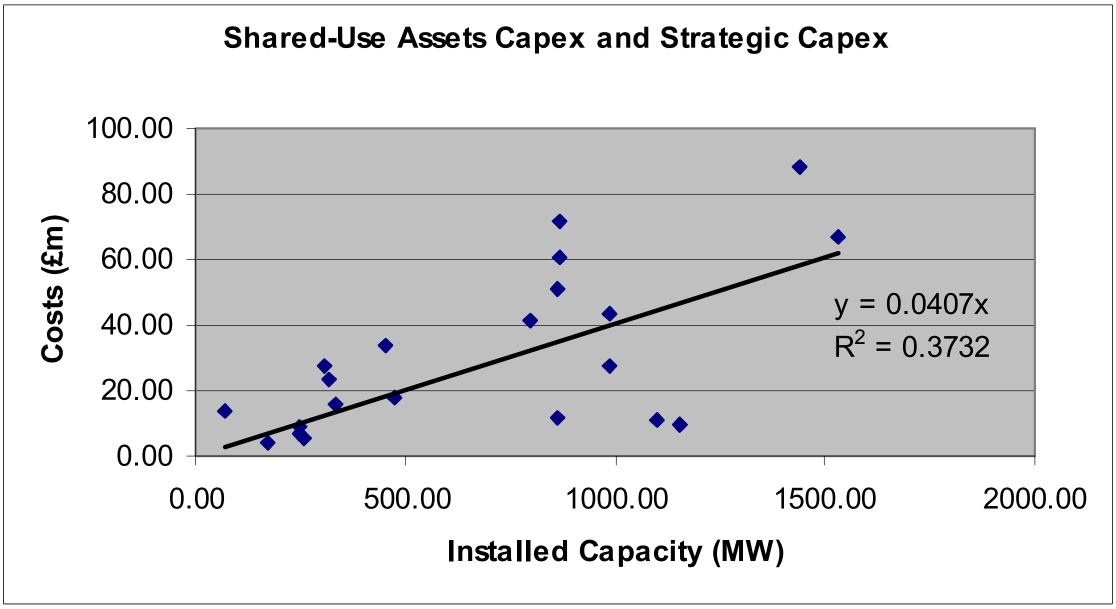

Figure 3-6 – High Level Costs for Future Period

A simple regression analysis indicates a unit cost value of approximately £41k/MW for the high-level future cost information including strategic investment, whereas a straight average gives £42k/MW. (Note that if those on 132kV assets are excluded from SPD's costs, these two numbers would become £31k/MW and £35k/MW.) However, the regression analysis highlights that the correlation of data with the average value is not particularly good. The high-level unit costs for each DNO are compared to this industry average in the following section.

Our assessments of the DNO unit costs for shared assets and strategic reinforcement are given in section 5.3.

4 Key Findings for each DNO

This section presents the key findings for each DNO from the DG-BPQ returns and the DNO visits, along with a summary of DG activity in each area. Where a company operates more than one licensed area, the findings have been presented as common observations followed by any specific observations for each licensed area. Our overall views on DNO forecasts, costs, and performance on DG connections management based on the DG-BPQ returns and visit interviews are given in section 5.

4.1 Aquila

4.1.1 Summary of DG Activity and DG-BPQ Data

Aquila is unusual among DNOs in having very few renewable resources. Of the 423 MW of existing generation, only 105 MW is renewable and few enquiries are expected in future. With no enquiries yet received for the period beyond 2005 and the low base of existing schemes, the forecast for the future is highly speculative. Aquila expects domestic CHP to be the largest contributor in future, with up to 100,000 units of 1.1 kW each, providing 110 MW of capacity. For onshore wind generation, Aquila has considered the potential generation at the few favourable sites it does have, estimated at up to 70 MW based on previous failed applications and a more conducive planning framework in future. The next largest expected contribution is from one or two large waste incineration plants, which Aquila acknowledges are likely to have difficulty with planning permission. While Aquila's estimates of future DG are based on previous failed enquiries and a general assessment of opportunity for each technology, these do not appear to have been balanced with a top-down assessment of likely generation or verified against any external studies.

Existing schemes have made use of existing network capacity. As this becomes filled, it is likely that unit costs will rise with newer schemes requiring significant reinforcement. This will be exacerbated by the change to shallow charging, which will potentially weaken the locational signals that previously affected the siting of DG.

Aquila states that there has been no quality of supply benefits from DG but has not considered the possibility of disadvantages.

Table 4-1 summarises the volume of project data provided by Aquila in the DG-BPQ return. Despite forecasting a moderate level of future DG capacity, Aquila provides no detailed project information for the future period on which to undertake analysis of likely future costs due to a lack of actual enquiries. Instead, a very broad range of total cost relating solely to switchgear replacement was entered as a high level estimate.

Aquila has omitted data on small projects from the detailed project information where no costs were incurred, which is not expected to impact the results of this analysis. Aquila's standard O&M figure is 22% of direct costs, however for the purpose of the DG-BPQ this has been presented as 18% of the total connection charge.

Table 4-1 – Summary of Project Data Provided for Aquila

	High-Level			Detailed		
	Historical	Interim	Future	Historical	Interim	Future
No. of Projects	15	12	33-91[1]	4	4	0
Capacity (MW)	91.0	19.5	70-309	68.2	8.2	0
Proportion of MW with shared costs	73%	0%	n/a	97%	0%	0%

1. Number of future projects in high-level information excludes technologies 8 & 9 (photovoltaic and micro-CHP) included in the DG-BPQ as there are very high numbers of small projects (up to 100,000 micro-CHP projects), however the capacity of these projects has been included.

4.1.2 DNO Meeting

The visit to Aquila Networks was carried out at Aquila's Tipton offices and a number of points were clarified surrounding the DG-BPQ submission. It was noted that Aquila's loss figures were calculated for the purpose of the DG-BPQ as the average change in loss between high and low load with and without generation. However the loss figures reported to settlement are Aquila's standard voltage related values or are site specific for very large generators.

Aquila levies a charge of 22% to cover O&M in connection charges but does not include any extra for planned "return". Credit for deferred renewal is given to developers based on the book life of assets, and for all reinforcement schemes in the current Development Plan. Connection charging in retrospect is the exception rather than the rule (mostly for very large schemes) with costs generally based on an estimate and paid by the customer at the time of accepting the connection offer.

Four generation connection design schemes ranging in size up to 60MW were examined in detail during the visit to Aquila Networks. It was noted that Aquila does not apply LDC and operates all rural primaries at 11.5 kV so there is therefore little margin to accept voltage rise due to generation. Using LDC would enable substations to run at a lower voltage on light load leaving headroom for generation to be added and would reduce generation connection costs in some cases. However Aquila reports that LDC is not a straightforward solution as there are technical problems and difficulties associated with its use on the network. Otherwise the schemes examined were found to be well designed without unnecessary costs.

4.2 EME

4.2.1 Summary of DG Activity and DG-BPQ Data

Historical penetration of DG in EME's area is relatively low, but the EME network has a mix of both urban and rural areas and there is potential for wind farms both in the Peak District and offshore. The 180 MW wind farm now accepted offshore at Skegness was cited as an example. EME has 940 MW of DG of which 815 MW was installed before 2000. Much of this was CHP but the recent downturn in this area is expected to cause distortion in cost averages. EME expects that future costs per kW will rise as DG penetration increases, particularly for offshore wind as early schemes can take advantage of network capacity, which will be denied to later schemes.

EME has completed the DG-BPQ tables but has categorised thermal-type DG schemes by fuel type, regardless of whether they are a CHP application or not. EME has developed a model to examine the future impact of DG, comprising three penetration levels and three cost cases. Forecast numbers of projects were derived and checked against previous estimates, trends in connection applications and a general view of published material and anecdotal evidence. It is clear that EME has undertaken a significant amount of work in examining scenarios for future DG penetration. However, verification of capacity levels and costs against external studies was not performed.

Table 4-2 summarises the volume of project data provided by EME in the DG-BPQ return. As can be seen only a small portion of future projects have been included in the detailed information, predominantly those with shared assets.

The loss factors quoted by EME in the DG-BPQ are the average loss to each voltage level of the network and not specific to individual schemes. EME has not entered any shared assets costs for the historical period but points out that such costs are likely in future when shallow charging removes the incentive to situate DG optimally. EME's model for future projects calculates a total length of connection and then allocates this partly to shared assets and partly to sole-use, typically in the range of 50% or 70% expected to be for the generator's sole-use. This approach is not consistent with the industry definition of sole-use assets based on the point of common coupling.

Table 4-2 – Summary of Project Data Provided for EME

	High-Level			Detailed		
	Historical	**Interim**	**Future**	**Historical**	**Interim**	**Future**
No. of Projects	22	16[1]	91[2]	7	5[1]	9
Capacity (MW)	67.3	99.7	865	37.2	22.6	352
Proportion of MW with shared costs	0%	0%	n/a	0%	0%	49%

1. Cost information was only provided for the five projects in the interim period that have had offers made, four of which were under construction at the time of completing the DG-BPQ.
2. Number of future projects in high-level information excludes 40,000 technology 9 projects (micro-CHP) included in the DG-BPQ; however the capacity of these projects has been included.

4.2.2 DNO Meeting

The visit to EME was conducted at EME's Castle Donnington offices and the following general points of clarification of the DG-BPQ information were discussed. Although EME generally calculates individual loss factors for EHV projects (33kV and above), standard loss factors have been entered in the DG-BPQ for the different voltage levels considered. DG connection charges cover connection costs and associated O&M costs, but not the cost of the initial feasibility study since this is normally charged separately to the customer before commencement. Costs for feasibility study work are therefore not reflected in the DG-BPQ submission figures. There is one example of active management employed on the network, but EME expressed some concerns that implementation costs may have been underestimated based on limited experience.

EME estimates that O&M costs will be 35% of direct costs in future, based on an annual cost of 4%, discounted for the life of the project at 7% for small projects and 9% for projects above 5 MW. Both the annual cost and the discount rates are higher than other DNOs. EME advised that the O&M cost had been determined based on the expected capital cost of each DG project in the future scenario, and represented an expectation of increased levels of active management.

Six DG connection design schemes were examined in detail during the visit. Some apparent inconsistencies were noted in connection costs regarding the calculation of O&M charges and several schemes showed a negative return. Otherwise there were no significant issues raised by EME's design approach.

4.3 The EdF Group – EPN, LPN and SPN

4.3.1 Summary of DG Activity and DG-BPQ Data

EdF has provided a comprehensive and well written document applicable to all three of its DNO licensees (EPN, LPN and SPN) followed by sections for each individual licensee. Common points are covered here and the licensee-specific points are covered in the sections below.

Some evidence exists in the DG-BPQ tables of the different historical ownership of the three EdF distribution license areas. The various policies in each licensed area are being progressively reviewed, standardised and streamlined where possible.

The connection of DG has resulted in no incidences of avoided reinforcement work in the historical or interim periods covered by the DG-BPQs and EdF does not anticipate any avoided reinforcement work resulting from the connection of DG in the future period. There has been no occurrence of annualised connection charges or ancillary services, and it has not been normal practice for EdF to estimate the effect of DG on quality of supply or losses.

No information is provided on DG existing before 2000. The predictions for the future period are generally based on the research and modelling work carried out on behalf of the DNOs by ILEX with variations for known circumstances and no comment is provided on the effects of shallow connection charging.

Strategic costs in the future period are higher than most of the other DNOs, particularly for operational expenditure.

(i) EPN

Approximately 500MW of DG capacity was connected to EPN's network during the historical period covered by the DG-BPQ but this includes one 420 MW CCGT project requiring significant network reinforcement. The other generation projects required only minor or no changes to the network. In the interim period, about 43 MW is expected made up mainly of landfill gas and onshore wind technologies. Forecasts for CHP are based on the ILEX scenarios, and for other technologies on an average of several forecasts ignoring the "Scottish Wind" scenario which EdF viewed as unlikely. The estimate was then checked against a bottom-up approach based on actual enquiries. In the future period it is expected that 800 MW of new DG will be connected, of which the largest component will be offshore wind. This is consistent with the UK Government's strategic plans for development of offshore wind off the Eastern coast of the country, particularly in the areas of the Greater Wash and the Thames Estuary. The key uncertainties associated with offshore wind are the timing of construction and the connection voltage, with larger projects possibly connecting at transmission level. A significant level of domestic CHP is anticipated in future, which we consider is subject to uncertainty.

The DG-BPQ return for EPN does not include any work on shared assets or work avoided although some major work on sole-use assets appears not to have been fully charged to the generator. There is no reference to future infrastructure reinforcement in the text but a forecast of £1m capex per year has been included for the future period. The EPN detailed project information for the future period omits a number projects with no impact on the network.

Table 4-3 summarises the volume of data provided in the DG-BPQ for EPN. A number of issues with the EPN data are as follows:

- In the interim period high-level information no projects have shared asset costs, however in the detailed project information two projects show shared assets;
- The future forecast estimates approximately 800 MW of new capacity associated with 24 projects, however the detailed project information includes 24 projects with a total capacity of only 365 MW, highlighting that actual average project size may be smaller than forecast by EPN;

Table 4-3 – Summary of Project Data Provided for EPN

	High-Level			Detailed		
	Historical	**Interim**	**Future**	**Historical**	**Interim**	**Future**
No. of Projects	24[1]	25	24[2]	7[1]	11	24
Capacity (MW)	74.6[1]	43.5	808[2]	23.2[1]	23.7	365
Proportion of MW with shared costs	0%	0%	n/a	0%	13%	34%

1. Excludes a 420 MW CCGT project which is considered unrepresentative for the purpose of this analysis. Detailed historical information also includes three projects not included in the high-level information. The capacity figure does not include these three projects as no capacity is given.
2. Number of future projects in high-level information excludes 180 technology 8 projects (photovoltaic) and 80,000 technology 9 projects (micro-CHP) included in the DG-BPQ, however the capacity of these projects has been included.

(ii) LPN

The DG-BPQ tables have been completed and the text provides a useful narrative. The historical period generation connected is 100 MW, the largest scheme being 29 MW, non-renewable. The remaining larger schemes are small- and medium-sized CHP, connected to customers' networks. None appear to have exported power. None of the schemes required work on shared assets and a number of projects do not have any sole-use assets. In the interim period all the known connections require no work on LPN assets and none are expected to export power. LPN is therefore unique in the industry and the cost of connection to its network is likely to differ from industry averages.

LPN has the advantage that the ILEX scenarios for its region resulted in only one set of assumptions for the future but comment is not provided on whether the scenarios are considered to be reasonable. The resulting forecast consists almost entirely of CHP with one known scheme for waste incineration added. The forecast levels of generation and technology mix appear reasonable for the LPN area. There is no mention of a need for infrastructure reinforcement and none is stated in the table.

Table 4-4 summarises the volume of project data provided for LPN. The single 70 MW project included in the detailed future information is likely to be unrepresentative of expected DG activity in the LPN network, which is predominantly made up of many small and medium-sized CHP projects.

Table 4-4 – Summary of Project Data Provided for LPN

	High-Level			Detailed		
	Historical	Interim	Future	Historical	Interim	Future
No. of Projects	12	18	25[1]	9[2]	18	1
Capacity (MW)	91.9	4.9	335[1]	68.0[2]	4.9	70
Proportion of MW with shared costs	0%	0%	n/a	0%	0%	100%

1. Number of future projects in high-level information excludes 667 technology 8 projects (photovoltaic) and 1,720 technology 9 projects (micro-CHP) included in the DG-BPQ, however the capacity of these projects has been included.
2. Detailed historical information includes three projects not included in the high-level information. The capacity figure does not include these three projects as no capacity is given.

(iii) SPN

The DG-BPQ tables have been completed and the text provides a useful narrative particularly on the details of schemes in all three periods. The historical period generation connected is 540 MW including a 400 MW CCGT scheme. The interim period only includes schemes that are under construction or where the generators have accepted the offer.

Forecasts for the future period are based on the ILEX scenarios increased where known schemes in particular technology types exceed the scenario projections. In particular, the ILEX work did not forecast the current activity in municipal waste generation and landfill gas generation and SPN has taken this into account in its forecast for future DG. In contrast to EPN and LPN, SPN does expect a significant number of domestic CHP schemes to appear in the future period. SPN's cost estimates for the future period are based on the ILEX work, compared with actual costs for projects, resulting in a total of £12m for shared assets associated with 471 MW of forecast DG capacity.

Table 4-5 summarises the volume of project information provided for SPN. Some gaps exist in the detailed future information where details were not available to SPN.

Table 4-5 – Summary of Project Data Provided for SPN

	High-Level			Detailed		
	Historical	Interim	Future	Historical	Interim	Future
No. of Projects	15[1]	7	10[2]	6[1]	4	4
Capacity (MW)	140.4[1]	15.0	472.0	80.0[1]	13.2	228
Proportion of MW with shared costs	3%	59%	n/a	3%	53%	100%

1. Excludes a 400 MW CCGT project which is considered unrepresentative for the purpose of this analysis.
2. Project numbers only provided for four technology categories, with seven other categories counting for 214 MW having no project numbers.

4.3.2 DNO Meeting

Points in common to all EdF Licensees

The visit to the EdF Group of Distribution Licensees took place at the EdF offices in Crawley and the following points of discussion were covered in clarification of the DG-BPQ returns and associated narrative document.

EdF believes that DG could increase network losses if the level of export from generators is greater than the local demand and the excess power needs to flow a long distance and across voltage levels. EdF is cautious about the calculation of loss factors, which depends heavily on assumptions regarding generation mix and consequent load flows. Currently there are different O&M policies in the different licensees. EPN levies 25% at 11 kV and 11% at 33 kV for O&M. SPN charged 28% historically but has now revised that to the industry standard of 25%, equivalent to 2.25% per annum over a 20-year asset life with a 6.5% discount rate. For higher voltage connections, EdF undertakes a bespoke calculation for O&M.

Based on anecdotal evidence EdF's view is that greater penetration of DG reduces the quality of supply, and transient stability under fault conditions could give rise to additional problems. Fast action circuit breakers would be needed to give generators a chance to ride through a fault, but time delays on circuit breakers may also be needed to ensure that the fault current on opening is within the break rating of the circuit breaker. These conflicting requirements are part of the challenge that greater penetration of DG is likely to bring.

Cost allowances are generally made and credited by EdF to DG projects where reinforcement work has been included in the ten-year development plan, and SPN has brought forward investment within a fifteen-year notional asset life. LPN and SPN make no return on DG connections but EPN currently allows a 10% return.

EdF has allowed for significant strategic reinforcement costs in the DG-BPQ data and commented that DG strategic costs are difficult to differentiate from load related strategic costs. Part of the DG related strategic costs arise from the need to revisit fault levels following a number of DG connections where it would not be fair or practical for a single subsequent project to bear significant incremental cost.

The research work by ILEX forms the basis for the future view of DG for all EdF Distribution Licensees. However, EdF commented that this research was based upon an average distribution network operator model and therefore clustering of DG may not be adequately accounted for. In addition the ILEX work did not recognise spare capacity on feeders constructed to higher voltage standards, nor did the study include potential growth from municipal waste to energy schemes.

(i) EPN

There was significant discussion during the visit surrounding the question of whether strategic reinforcement should be carried out where several projects were proposed. This is particularly relevant for EPN where substantial offshore wind generation development appears likely. In EPN's view a strategic reinforcement approach as opposed to a piecemeal approach would result in a more resilient overall network though not necessarily a cheaper solution in the long term.

Five DG design projects ranging in capacity up to 12 MW were examined in detail covering a range of DG technologies. All appeared to be well designed without unnecessary costs. It was noted that the requirement for separate metering for projects eligible for Renewables Obligation Certificates (ROCs) could lead to extra costs of connection where existing Non-Fossil Fuel Obligation (NFFO) projects are extended to exploit further DG potential.

(ii) LPN

LPN reports that in general there is fault level headroom on its network for DG and CHP applications have to date been connected with little additional reinforcement cost. In future LPN anticipates that there may be a step change in costs, in particular if applications are clustered locally. In such cases there would be significant extra costs arising from the need to establish new 132/11 kV substations and change switchgear in dense urban areas where space is at a premium.

The impact of DG on LPN's network in future depends heavily on the uptake of waste to energy and CHP technologies. Without these two technologies it looks likely that the only extra generation added will be PV applications and domestic CHP.

One DG design project was examined in detail in LPN's licensed area. This was a 5 MW CHP generator and was one of the few schemes in the DG-BPQ listing sole-use asset costs. An inter-trip scheme was necessary to isolate the generators under loss of supply conditions when the local busbars operate with a single in-feed due to maintenance outage. Under these conditions it is necessary to avoid the DG back-feeding other customers via the local 11 kV network.

(iii) SPN

SPN design policy differs significantly from other DNOs in its requirement that circuit breakers be rated to withstand out-of-phase switching of generators. Although out-of-phase switching would not be done intentionally, in the worst case an operator could mistakenly close onto a generator 180 degrees out of phase thereby exceeding the normal fault rating of the switch and possibly incurring injury as a result. For health and safety reasons SPN therefore requires replacement of switchgear not meeting the out-of-phase switching rating which leads to extra connection costs being incurred in some cases.

In addition SPN does not permit the operation of its circuit breakers from customers' protection equipment due to concerns over the integrity of protection settings. In some cases this results in the need to install an extra circuit breaker on the customer side of the metering circuit breaker adding about £12 k to the connection cost of an 11 kV project for example.

SPN believes that many landfill schemes are likely to be re-engineered and a number of sites that have hitherto been uneconomic may be brought forward as a result of the Renewables Obligation. In addition significant onshore and offshore wind projects are under discussion with developers and are likely to move forward. SPN would appear to have more DG potential than has been ascribed to it by many commentators.

Five DG connection design schemes ranging in capacity up to 90 MW were examined in detail during the visit. These projects covered onshore wind, offshore wind and landfill gas technologies. The SPN designs were effectively engineered and demonstrated an innovative and flexible approach to customer requirements.

4.4 WPD – South West and South Wales

4.4.1 Summary of DG Activity and DG-BPQ Data

Points in common to both WPD Licensees

WPD has provided a section of common text applicable to both of its DNOs. All tables have been completed but the average return in the connection charge is not provided. All schemes in South West are given a 5% loss factor based on a predictive model. For South Wales, the values vary between schemes but are all positive for historical schemes and omitted for interim schemes.

In the historical period there has been very little shared asset or reinforcement modification. WPD points out that potential generators are given strong locational signals by the current deep reinforcement charging system. With shallow charging, generators are likely to cause DNOs to incur costs for the deep reinforcement. The interim period includes only known schemes and WPD points out that there may be other short timescale schemes, which are not yet known.

The forecast for future requirements is based on the ILEX scenarios with a small number of known schemes added and the total then scaled back to match the scenarios. Sole-use costs for the future scenarios are estimated by simple cost/kW by generator type. WPD has not examined shared asset costs in detail but has used the ranges provided by ILEX when completing the DG-BPQ.

WPD has not entered any agreements for generation constraints or ancillary services. In future, there will be less incentive for a generator to accept constraints if shallow charging is adopted. They do not consider that any DG commissioned has had any quality of supply impact.

WPD has not identified any avoided work or infrastructure reinforcement.

(i) WPD South West

WPD has used the cost ranges provided by ILEX when completing the DG-BPQ, resulting in unit cost for shared assets and strategic investment for WPD South West ranging from £23k/MW to £75k/MW based on minimum cost for minimum capacity and maximum cost for maximum capacity. Other combinations of capacity and cost ranges result in slightly lower and higher unit costs respectively.

Table 4-6 summarises the volume of project data provided for the WPD South West network. Only a small number of projects have been included in the detailed information for the interim and future periods, due to the low number of enquiries as discussed above.

Table 4-6 – Summary of Project Data Provided for WPD South West

	High-Level			Detailed		
	Historical	Interim	Future	Historical	Interim	Future
No. of Projects	9	22	24[1]	6[2]	3[3]	3[3]
Capacity (MW)	42.3	37.5	175-316	14.0[2]	24.9	66
Proportion of MW with shared costs	9%	0%	n/a	28%	0%	0%

1. Number of future projects in high-level information excludes 6,000 technology 8 projects (photovoltaic) and

41,000 technology 9 projects (micro-CHP) included in the DG-BPQ, however the capacity of these projects has been included.

2. Detailed historical information includes three projects not included in the high-level information. The capacity figure does not include these three projects as no capacity is given.

3. WPD provided only a small selection of typical projects for the interim and future projects.

(ii) WPD South Wales

As mentioned above, WPD has used the cost ranges provided by ILEX when completing the DG-BPQ, resulting in unit costs for shared assets and strategic investment for WPD South Wales ranging from £22k/MW to £74k/MW.

Table 4-7 summarises the volume of project data provided for the WPD South Wales network. Only a small number of projects have been included in the detailed information for the interim and future periods, due to the low number of enquiries as discussed above.

Table 4-7 – Summary of Project Data Provided for WPD South Wales

	High-Level			Detailed		
	Historical	**Interim**	**Future**	**Historical**	**Interim**	**Future**
No. of Projects	45[1]	22	44[2]	6	3[3]	3[3]
Capacity (MW)	70.9	134.7	261-455	8.7	38.2	308
Proportion of MW with shared costs	0%	0%	n/a	0%	0%	32%

1. High-level information for historical period includes 21 very small projects with capacity less than 1 kW, for which no connection charge was made.

2. Number of future projects in high-level information excludes 5,000 technology 8 projects (photovoltaic) and 30,000 technology 9 projects (micro-CHP) included in the DG-BPQ, however the capacity of these projects has been included.

3. WPD provided only a small selection of typical projects for the interim and future projects.

4.4.2 DNO Meeting

Points in common to both WPD Licensees

The visit to WPD was conducted at the Bristol offices and the following issues were discussed to clarify the DG-BPQ return and associated narrative.

Loss figures provided in the DG-BPQ for 33 kV and 132 kV are based on a model designed by EATL to allocate losses based on time bands and voltage levels, and at 11 kV and LV losses are quoted as standardised values. South West has historically levied 19% of direct cost to cover O&M and South Wales has used 21%, but both licensees have recently standardised on 19%. For larger schemes a specific O&M cost is calculated resulting in O&M rates generally lower than the standard 19%. WPD reports that annual charges for O&M are not common and WPD does not favour annual charging for connection costs due to credit risk and would only do so if backed by a bank guarantee or parent company guarantee.

WPD charges developers for all new equipment unless replacement is planned for the next five years in which case the developer pays the cost of bringing the renewal forward. WPD has a condition-based replacement policy rather than age-based and although credit would be given against connection charges (taking due account of the risk of failure after reinstallation) if plant is reusable. WPD considers that DG has not yet had an impact on quality of supply, but it may do in the future, most likely after 2010. Beyond 2010 WPD intends to design the network so that DG does not have an adverse effect. WPD does not have any formal constraint contracts but has the ability to constrain generators in relevant connection agreements.

WPD's future scenarios for DG are based on ILEX research adjusted by reference to a sample of actual projects. Sole-use costs have been based on historical WPD specific connection costs, and reinforcement costs are based on modelling using a normalised network around each of WPD's Grid Supply Points (GSPs) combined with averaged unit element costs.

WPD's approach to DG is positive and this is supported by the website publication of files showing its 132 kV and 33 kV networks to help developers select the best connection locations. Specific generation connection design schemes investigated during the visit showed WPD to be generally thorough and professional in dealing with DG, and pro-active in encouraging connections.

(i) WPD South West

Four DG connection design schemes in the South West licensed area covering a range of technologies up to 50 MW capacity were examined in detail during the visit. An inconsistency was found in the allocation of costs between sole-use and shared-use assets and WPD undertook to review the DG-BPQ information to ensure this had not been repeated elsewhere. In engineering terms the schemes were well designed to customer requirements without unnecessary plant or costs.

(ii) WPD South Wales

Four DG connection design schemes in the WPD South Wales licensed area, mainly onshore wind power, were examined in detail during the visit. Generally WPD allows customer's protection to operate WPD metering circuit breakers covering small amounts of the customer's distribution system. The design approach adopted was sound in each case and did not entail any unnecessary plant or costs.

4.5 CE Electric (UK) – NEDL and YEDL

4.5.1 Summary of DG Activity and DG-BPQ Data

(i) NEDL

NEDL has experienced a large amount of DG historically, largely due to industrial CHP projects. 53 MW of DG has been installed in the last three years and total DG is currently 810 MW, of which 600 MW is CHP, 80 MW is renewables and 130 MW is other generation. Policy has been to charge all connection and reinforcement costs to generators.

Future projects have been examined as clusters to evaluate their impact on individual grid supply points. Sole-use costs have been established based on typical connection costs for different sizes of connections. In estimating costs, NEDL has not identified a need for any newly installed shared assets. Reinforcement estimates are based on the assumption that fault level limitations will be more critical than voltage or thermal considerations, which appears to be a reasonable approach. NEDL points out in its narrative accompanying the DG-BPQ that a significant uncertainty exists in estimating costs on an average basis due to the large influence of network capacity in the location of a project.

The DG-BPQ tables have been largely completed but a degree of uncertainty exists due to the forecasting methods used for future projects. No areas have been identified for strategic investment.

Table 4-8 summarises the volume of project data provided by NEDL.

Table 4-8 – Summary of Project Data Provided for NEDL

	High-Level			Detailed		
	Historical	**Interim**	**Future**	**Historical**	**Interim**	**Future**
No. of Projects	20[1]	7	532[2]	20[1]	7	n/a[3]
Capacity (MW)	49.7[1]	5.6	1152.9	49.7[1]	5.6	n/a
Proportion of MW with shared costs	25%	0%	n/a	31%	0%	n/a

1. Project DI 14963 included twice in both high-level and detailed information in DG-BPQ. Shared asset cost shown in detailed information but not high-level information

2 Number of future projects in high-level information excludes 1,400 technology 8 projects (photovoltaic) and 11,540 technology 9 projects (micro-CHP) included in the DG-BPQ, however the capacity of these projects has been included.

3. NEDL has not provided detailed information for projects in the future period but has provided aggregated figures based on its forecast for future DG and associated estimates for reinforcement costs. It is not possible to determine from this information the proportion of MW with shared costs.

(ii) YEDL

DG connected to the YEDL network currently totals 920 MW comprising 600 MW of CHP, 120 MW of renewables and 200 MW of other generation. 200 MW of generation has been connected since April 2000, mostly small projects in the 1 to 12 MW range. As with NEDL, YEDL policy has been to charge the full cost of connection to the generators, including a proportion of the O&M costs. No returns have been made on connections and only minor reinforcement work has been required. Forecast DG at 2010 is 2019 MW, an increase of around 1100 MW on present connections.

Analysis of costs is based on clusters around grid supply points using typical connection costs and estimated deep reinforcement costs. In the same was as NEDL, YEDL has not identified a need for any newly installed shared assets in its cost estimates. Reinforcement estimates are based on the assumption that fault level limitations will be more critical than voltage or thermal considerations, which appears to be a reasonable approach.

Table 4-9 summarises the volume of project data provided by YEDL. The DG-BPQ tables have been largely completed but a degree of uncertainty exists due to the forecasting methods used for future projects. No areas have been identified for strategic investment. YEDL has reported positive loss adjustment factors as reducing load, which is the opposite of Ofgem's requested interpretation in the guidance notes.

Table 4-9 – Summary of Project Data Provided for YEDL

	High-Level			Detailed		
	Historical	Interim	Future	Historical	Interim	Future
No. of Projects	31	1	572	31[1]	1	n/a[2]
Capacity (MW)	210.1	6	1097.4	160.1[1]	6	n/a
Proportion of MW with shared costs	23%	0%	n/a	27%	0%	n/a

1. One project in the detailed historic information does not appear in the high-level information so it is not possible to determine the capacity of this project.
2. YEDL has not provided detailed information for projects in the future period but has provided aggregated figures based on its forecast for future DG and associated estimates for reinforcement costs. It is not possible to determine from this information the proportion of MW with shared costs.

4.5.2 DNO Meeting

Points in common to both CE Electric (UK) Licensees

The visit to the CE Electric (UK) was conducted at the Castleford offices and the following general points were covered relating to the DG-BPQs for both licensees. Losses in DG-BPQ tables are all voltage-dependent standard values assuming that generators reduce losses. YEDL levies O&M charge at 25% of connection cost derived from 2.25% capitalised at 6.5% over a project life of 20 years. NEDL charges 0.98% per annum charged on an annual basis or at the customer's request capitalised at 6.5% over the scheme life. NEDL reports that most generators prefer the capitalised version. CE Electric (UK) is planning to standardise on the NEDL approach. DG connection costs are determined so as to give no return.

CE Electric (UK) is cautious about the re-use of recovered plant, and switchgear over five years old would not be re-used. Transformers that are re-usable are credited against the DG connection charge at 70% of new cost. Both CE Electric (UK) licensees allocate sole-use costs where the generator is the sole "beneficiary" of the asset and this leads to the allocation of sole-use assets upstream of the point of common coupling in some cases. Both NEDL and YEDL give credit to DG only where reinforcement schemes have been formally authorised. In practice these are only in the first 18 months or so of the network development plan so there is low likelihood of credit to DG for avoided reinforcement.

CE Electric (UK) believes that DG will decrease the quality of supply initially, due to extra equipment, connection outages, and network management complexity, but in the long term there may be gains due to generator support and improved voltage control. Since 11 kV generators are usually not stable for fault ride-through under fault conditions, pole slipping may occur with consequent voltage disturbance, but at 33kV faster protection operation may overcome this difficulty.

CE Electric (UK) described the methodology underpinning the estimation of future impact of DG on its networks. This appeared to be sound and well thought through, however the forecast level of DG activity appears high and the associated costs appear low. Some minor inconsistencies in the DG-BPQ scheme numbering and information were found which were subsequently corrected by CE Electric (UK).

(i) NEDL

Five DG connection design schemes ranging in technology and size up to 10 MW were discussed in detail and the approach was found to be well engineered and without unnecessary plant or cost. Overhead lines are more frequently specified in the NEDL area than the YEDL area and a project in which the customer's protection equipment was permitted to operate the metering circuit breaker was included.

(ii) YEDL

Five DG connection design schemes were examined in detail in the YEDL licensed area and these were all well engineered to customer requirements without unnecessary costs.

4.6 SPD and SPM

4.6.1 Summary of DG Activity and DG-BPQ Data

Scottish Power has completed separate DG-BPQs for the Scottish Power Distribution (SPD) and Scottish Power Manweb (SPM) licensees. Separate narrative responses were also provided for the two licensees. Both the DG-BPQs and the narratives were of high quality and provided a good picture of historical, interim, and future DG activity in the relevant areas.

(i) SPD

SPD foresees a large increase in DG in its network area in the period 2005 to 2010. Historical DG installation has been low at only 115 MW total. Forecasts for future projects are based on actual generator enquiries and Government aspirations, checked against work by OXERA (Regional Resource Report) and the Scottish Executive Resource Study, and only include onshore wind and landfill gas. In contrast to other DNOs, SPD has included no estimates for CHP or other technologies due to a lack of enquiries and a belief that the CHP targets will not be met.

Two areas have been identified by SPD as requiring forward-looking investment: Borders and South West Scotland. Plans have been prepared for progressive reinforcement of the network in these areas. Although 132 kV is considered transmission voltage in Scotland, some reinforcement at 132 kV was included in the DG-BPQ as distribution work where it directly supports identifiable distribution schemes. The costs associated with 132kV work were subsequently removed and updated figures derived for distribution level costs only.

All of the DG-BPQ tables have been completed. Detailed information has been provided for those forecast future projects at offer and feasibility stage, representing 17 out of 73 total projects identified in the high-level information for the future period across the range of technologies. This information should allow a reasonable picture of DG costs to be derived. There is no occurrence of work avoided on shared assets in the tables for historical, interim or future projects.

SPD lists a low cost for shared assets of only £5.2m for capacity of 1437 MW, but a high strategic Capex of £14.27m (the original figure, including 132kV costs, was £82.81m) which includes strategic reinforcement for the Borders and South West areas, and other general strategic reinforcements. The strategic reinforcement is the reason that individual projects are not exposed to high shared asset costs, However it appears from the DG-BPQ that SPD has included considerable amounts of shared asset costs for projects in the strategic costs table, which could distort any analysis on a project basis.

Table 4-10 summarises the volume of project data provided by SPD. Considering the large number of enquiries included in the high-level information (73), the 17 projects included in the detailed information are not a large sample and a better insight could be gained into connection costs if SPD was able to provide details on more of its current projects.

Table 4-10 – Summary of Project Data Provided for SPD

	High-Level			Detailed		
	Historical	Interim	Future	Historical	Interim	Future
No. of Projects	8	6	73	8	6	17
Capacity (MW)	76.8	84.1	1437	76.8	84.1	651
Proportion of MW with shared costs	58%[1]	61%	n/a	17%[1]	61%	62%

1. The same projects are included in both the high-level and detailed information for the historical period, however one project with shared assets in the high-level information has no shared assets in the detailed information, and another project has different cost values for the same shared assets in the high-level and detailed information.

(ii) SPM

SPM currently has a large amount of generation connected to its network and expects continuing significant DG activity in its area in future. Connected capacity is currently around 1000 MW, of which 700 MW is CHP in the industrial areas of Merseyside and Cheshire. Forecast future DG is 827 MW comprising mostly onshore and offshore wind with a small amount of CHP/landfill gas. As with SPD, SPM's forecast is based on actual enquiries so appears to be robust.

Three areas in the SPM area, Denbigh Moors, Mid-Wales and Merseyside, have been identified as hot spots that are likely to experience a large number of projects. SPM reported that it would be more efficient to reinforce the infrastructure in these areas in a forward-looking manner. The DG-BPQ stated that the investment scheme identified for Mid-Wales would be required for demand growth around 2009. It gave information on both the total scheme cost as well as the cost for advancing it from 2009 to 2005. Other areas will require general reinforcement and active network management.

The DG-BPQ tables have all been completed and present a good picture of DG in the SPM area. Forecasts for future projects appear robust, being based on current applications and enquiries, political aspirations, and clusters of past failed projects whose failure could be attributed to connection costs. Estimates have been checked against OXERA work on behalf of the DTI, and EA Technology work also for the DTI. SPM has estimated the extent of works required in each of the three strategic areas identified and the associated costs. It is worth noting that in both historical and forecast future projects, SPM shows no work avoided on shared assets.

Table 4-11 summarises the volume of project data provided for SPM. The detailed project information in the future period only includes six projects, none of which provide costs for shared assets, which makes analysis on a project basis difficult.

Table 4-11 – Summary of Project Data Provided for SPM

	High-Level			Detailed		
	Historical	**Interim**	**Future**	**Historical**	**Interim**	**Future**
No. of Projects	14	8	35	10	8	6
Capacity (MW)	111.8	173.1	987	79.8	173.1	364.5
Proportion of MW with shared costs	41%	34%	n/a	23%	34%	27%[2]

1. Three projects listed share a common network solution, for which only a total shared asset cost is provided.
2. One project in the future period has a requirement for reinforcement, but refers to the strategic reinforcement of Merseyside for its shared asset costs.

4.6.2 DNO Meeting

Points in common to both SP Licensees

The visit to the SP licensees took place at the SP offices in Bell's Hill near Glasgow and the following points were discussed to clarify understanding of the DG-BPQs and associated commentary documents.

Loss factors have not been entered because SP assesses that any reduction in losses from DG is likely to be balanced by local increases and therefore assumes that DG has no overall effect on losses. Both SP licensees levy O&M at 2.25% per annum discounted at 6.5% over the life of the project. This is total operating costs for the SP licensees divided by the value of the asset base and is therefore the average cost for existing SP networks.

Historically both SPD and SPM charged all DG connection associated costs to the relevant generation project unless there were resulting "betterment" gains to the network or if equipment was already programmed for replacement under the asset management schedule. Connection cost drivers in the past have been mainly fault level and voltage control issues and to a lesser extent thermal issues and SP does not include a return in DG connection charges as assets are added to the regulated asset base. SP reports that developers don't generally ask for constrained connections.

No enquiries have been made for either Micro-CHP or other larger CHP schemes and therefore no CHP scenarios were included in the DG-BPQ.

(i) SPD

SPD has already carried out significant strategic reinforcement and this has facilitated the connection of DG in the historical and interim periods. SPD reports that the main cost elements of future strategic reinforcement are likely to be replacement and addition of 132/33 kV transformers. The SPD strategic reinforcement proposals appear reasonable if generator clustering occurs in expected locations but there is a risk that the extra capacity provided might not be located as forecast by SPD.

Five DG connection design schemes ranging in size up to 50 MW were examined in detail during the visit. The designs chosen by SPD appeared to be the optimum from a number of alternatives considered and were all well engineered and without unnecessary costs.

(ii) SPM

SPM considers that significant strategic reinforcement will be necessary in its licensed area to facilitate future potential for the connection of DG since existing connections fill the available capacity in Mid-Wales and Denbigh Moor areas. A new Grid Supply Point (GSP) in Mid-Wales is probably not achievable due to the long distance in a difficult area and would still require 132 kV and 33 kV lines to connect new generators. Therefore the SPM proposed infrastructure reinforcement is by 132 kV extensions from the existing GSP.

Five DG connection design schemes ranging in size up to 60 MW were examined in detail during the visit. These appear to have been designed effectively, but in some cases include circuit breakers that seem unnecessary in our view.

SPM design standards require the DG metering circuit breaker to be connected via a short length of cable with unit protection to an additional customer's main circuit breaker so that faults on the customer's system do not operate the metering circuit breaker. SPM does not accept jointly-owned switchboards consisting of an incoming metering circuit breaker with a customer's busbar and feeder circuit breakers although it was stated that this latter policy may change in future.

In its design approach SPM appears to rely rigidly on written policies and design standards, which often imply the need to install several circuit breakers where most DNOs would manage with fewer. This rigid adherence to standard systems has no doubt reduced training costs in the past but is now causing additional costs to DG connections. The standards used by SPM seem to be out of line with general DNO practice.

4.7 United Utilities

4.7.1 Summary of DG Activity and DG-BPQ Data

United Utilities currently has a moderate amount of generation connected to its network. Many potential renewable projects have not gone ahead due to the high reinforcement costs that would be incurred in reinforcing the constrained 132 kV network, particularly in Cumbria where three large power stations and a number of renewable projects use the 132 kV network to supply power to National Grid. DG in the future period between 2005 and 2010 is expected to be between 987 MW and 1,530 MW based on three key renewables scenarios, comprising mostly onshore and offshore wind, and two CHP scenarios. These scenarios are based on an extensive investigation performed by UU using a number of external resources. UU appears to have embraced the likely increase in DG and has established a special unit to promote the business changes necessary in accommodating future DG. The UU DG-BPQ submission and associated commentary are of high quality. UU appear to have made appropriate use of external information to ensure their submission was based on well informed forecasts, and have done as much as possible in turning these forecasts into likely costs.

To determine connection costs for the DG-BPQ return, UU has developed a high level model based on the scenarios for renewables and CHP. This model has identified a number of broad-brush strategic reinforcements of the network, mostly at the 132 kV level with some 33 kV work. However, concern exists over making this investment considering the uncertain nature of project developments. UU makes the point that it is difficult to judge future connection costs based on historical data as the number of connections has been low and a range of business change costs are expected to occur in future.

Increasing losses have been identified by UU as a key issue in its network. Unlike most other DNOs, there are likely to be increasing reverse power flows at the higher voltages in UU's network, both seasonally and by time of day in the future period resulting from the installation of increased levels of DG, which could lead to a significant increase in distribution losses.

Table 4-12 summarises the volume of project data provided for UU. We note a possible discrepancy between the high-level and detailed project information regarding average project size for the future period in that the maximum scenario includes 310 individual projects counting for 1530 MW, whilst the detailed information includes 995 MW across only 39 projects. However, this may be simply due to UU choosing to include the larger projects of the future period in its DG-BPQ submission.

Table 4-12 – Summary of Project Data Provided for UU

	High-Level			Detailed		
	Historical	Interim	Future	Historical	Interim	Future
No. of Projects	36	6	310[1]	7	6	39[2]
Capacity (MW)	122.6	59.3	1530	92.6	59.3	995.2
Proportion of MW with shared costs	89%	0%	n/a	97%	0%	617

1. Number of future projects in high-level information excludes 1,000 technology 8 projects (photovoltaic) and 46,000 technology 9 projects (micro-CHP) included in the DG-BPQ, however the capacity of these projects has been included.
2. Future detailed project information contains five actual project enquiries totalling 330.4 MW and 34 pseudo projects examined by UU in the Cumbria region totalling 664.8 MW.

4.7.2 DNO Meeting

The visit to UU took place at its Manchester offices and the following points were covered in clarification of the DG-BPQ response and associated narrative document. All generation projects in the detailed information section of the DG-BPQ have an assumed loss reduction, though UU pointed out that there were other DG projects that could have material impact on increasing the losses. Losses are not individually calculated for 11 kV DG connections where UU uses a matrix of standard values, but are site-specific at 33 kV and above. O&M charges are 14% initial capital sum, and this rate is based on the overall ratio of UU operational costs to asset base value. UU avoids circuit breakers in series and allows customer's protection to operate UU metering circuit breakers unless there is an onerous or unusual duty expected (such as protecting extensive offshore cabling). If assets are replaced to facilitate DG connection where reinforcement schemes have already been approved the full new asset cost is allowed as credit against the DG connection charge. However, UU's experience is that independent approved schemes overlapping with DG customer requirements are unusual and generally only scrap value is allowed as credit for removed plant.

Five DG connection design schemes each of around 10 MW capacity were examined in detail and the UU designs were found to be soundly engineered without unnecessary costs. It is noteworthy that the answers provided by UU to all the questions raised were well prepared and presented and UU are clearly taking a pro-active approach to DG.

In order to provide the best possible forecast for DG UU has built a network model for DG costs that was tested with studies for Cumbria based first on network expansion on a project-by-project basis and secondly on strategically led network expansion considering all projects at the same time. The results indicated that the strategic approach yielded few benefits over the incremental design approach in terms of overall cost saving, but also showed that incremental projects precipitated the need for major expenditure on the 132kV network that was unfair to levy on any one project.

4.8 SSE – SEPD and SHEPD

4.8.1 Summary of DG Activity and DG-BPQ Data

SSE believes that the move toward shallow reinforcement charging will significantly impact the cost of DG as generators will select more sites that require deep reinforcement as opposed to historical behaviour of selecting sites with little or no reinforcement requirement. To provide some protection for DNOs under the incentive mechanism, SSE believes that the duty to provide connections should be relaxed so that generators can still be encouraged towards favourable points in the network. SSE also questions the level of scrutiny into DG when the same scrutiny is not applied to load-related expenditure across the industry.

SSE has completed the DG-BPQ tables thoroughly and details have been provided for all projects in the historical, interim and future periods. Information on export MWh has not been provided due to being confidential and generally not available. SSE's cost forecasts for the interim and future period are based on actual connection applications with a margin added so the figures provided are likely to be a good representation of actual activity.

(i) SEPD

Penetration of DG in the Southern Electric network has been limited to date, with only 51 MW installed in the historical period. These projects are mostly landfill gas and solid waste projects as the region does not have a significant wind resource or industrial sector to attract CHP. However, future activity is predicted to be substantial at 380 MW (130 MW in interim period, 250 MW in future period) based largely on actual enquiries. No activity is forecast for domestic CHP and whilst SEPD's estimates are based on actual enquiries, these do not appear to have been verified against external studies.

No reinforcement work has been required in connecting the historical projects to the network; however reinforcement is required for projects in the interim period and will be required in the future period. SSE has not identified any areas for strategic investment in the Southern Electric network.

Table 4-13 summarises the volume of project data provided by SEPD. In the future period, all projects from the high-level forecast appear in the detailed information, providing good consistency in the DG-BPQ information.

Table 4-13 – Summary of Project Data Provided for SEPD

	High-Level			Detailed		
	Historical	Interim	Future	Historical	Interim	Future
No. of Projects	9	20	15	9	20	15
Capacity (MW)	51.0	128.5	248	51.0	128.5	248
Proportion of MW with shared costs	0%	56%	n/a	0%	56%	74%

(ii) SHEPD

The North of Scotland is expected to attract a large penetration of renewable generation in future, mostly from onshore wind. SSE reports 4500 MW of current activity based on actual enquiries and accepted connection applications. A large proportion of this generation will be at transmission voltage (which includes 132 kV in Scotland), however around 1000 MW is expected to connect to the distribution network. SHEPD is investing much time and effort in responding to the large number of enquiries for onshore wind projects and has based its forecast for future on projection of current activity levels.

The strategic reinforcements envisaged by SHEPD are £2.2m for a static VAr compensating device for Orkney in the interim period and £7m for strategic reinforcement of remote island networks in the period 2005 to 2010.

SHEPD has not provided loss adjustment factors, noting that it is policy in the north of Scotland to use unity factors. This was discussed during the visit to SSE and further comment is provided below.

Table 4-14 summarises the volume of project data provided by SHEPD. The 84 projects included in both the high-level and detailed future information provide an excellent insight into the cost drivers in the SHEPD network.

Table 4-14 – Summary of Project Data Provided for SHEPD

	High-Level			Detailed		
	Historical	Interim	Future	Historical	Interim	Future
No. of Projects	17	18	84	17	18	84
Capacity (MW)	80.6	293.1	794.7[2]	80.6	293.1	794.7[2]
Proportion of MW with shared costs	0.2%	29%[1]	n/a	0.2%	29%	38%

1. High level information for interim period includes one project with O&M and return on shared assets but zero direct costs for shared assets. This project has been excluded from the proportion of MW with shared asset costs for consistency with the detailed information.
2. Excludes 72 MW of "other" type projects for which only aggregated information was provided.

4.8.2 DNO Meeting

(i) Points in common to both SSE Licensees

The visit to the SSE licensees was carried out at the Scottish Hydro Electric Power Distribution (SHEPD) premises in Perth. The generation connections process is the same for both SSE Licensees and does not differ significantly from procedures in other DNOs. SSE generally charges 20% for O&M but where requested quotes on a site-specific basis according to the maintenance level of the assets used. SSE gives credit to developers where work is already in their 5 year plan. Credit is also given for recovered items of plant where they are reusable, and on O&M charges on removed assets. The target return expected by SSE is in the order of 8% for generator connection schemes. Neither licensee expects significant micro CHP development in the period to 2010.

(ii) SEPD

Loss factors are derived from SEPD's generic system model, but site-specific values are used if schemes are non-typical. Four generator connection design schemes were examined in detail ranging from 1.25 MW to 50 MW connected generating capacity. The designs appeared to be well engineered without unnecessary cost and no particular issues were identified for further comment.

SEPD sees potential for CHP in the region but in common with all other DNOs, SEPD reports lack of activity in the CHP sector at present.

(iii) SHEPD

The 132kV system is classed as Transmission in Scotland and the SSE Transmission connection policy is to levy shallow initial connection charges with ongoing TUoS (Transmission Use of System) charges. SSE accepts generation connections based on a winter load design condition, the application of the security standards, and constrained (complete with compensating payment) operation during the summer and spring/autumn periods. SHEPD Distribution connection policy is to levy single deep connection charges with generation effectively connected on a "fit and forget" basis. However SHEPD has allowed managed (inter-trip) schemes to connect to the Distribution system on Orkney (without compensating payment), where the economics of reinforcement are particularly harsh. SSE is also considering other similar locations in the North for such arrangements, where generation connection activity is high.

SHEPD maintains close contact with Planning Departments to discuss implications of Government policy and to establish limits to DG and increments of reinforcement including associated overhead lines. SHEPD reports that planners are generally cooperative as wind farms are seen as beneficial to employment in the region.

SHEPD appears very flexible in their approach to DG and willing to adapt to varying customer requirements. Five generator connection design schemes were examined in detail ranging from 30 kW to 150 MW and all appeared to be designed well with additional plant included only where specifically requested by the customer.

5 Assessment of DNO DG Forecasts, Costs, and Performance

In this section we provide our overall assessment on key issues of DNO DG forecasts, cost projections, and performance arising from examination of the DG-BPQ Returns and subsequent visits to each Licensee.

5.1 Volume of DG Projects

The DNOs have all undertaken systematic assessment of project volumes, but have given different weightings to actual connection applications and levels of development activity they are aware of, as compared with high-level scenario planning at national and regional level based on projections of growth potential of CHP and renewable technologies. Both of these approaches have drawbacks:

- Connection applications are only a partial indicator of whether a project will proceed. Delays or cancellation can occur for a wide range of reasons, including planning consent problems, inability to raise finance, and requirement to focus development effort on other projects.
- Connection applications tend to give only a limited view into the future; developers' plans currently look to around 2006 (2008 for offshore wind). There is therefore uncertainty as to what will be built towards the end of the next price control period. In addition, applications for new transmission connections in Scotland after 2006 will be examined on a case-by-case basis considering impact on the transmission system, which may serve to increase the uncertainty of forecast volumes based on projections from current connection application activity.
- Scenario based planning is inevitably uncertain, and the macro results it yields are difficult to map onto the relatively local issues that govern success of individual projects, for example the attitudes of a particular planning authority or the availability of a particular fuel resource in a local area, both of which are highly relevant to considerations of network investment
- The scenarios used for renewable DG, which many of the DNOs worked with ILEX to develop, are based on achievement of the Government's 2010 target. Independent work undertaken by ourselves, involving the identification of actual project commitments and those projects under serious development, indicates that there are firm proposals which would result in achieving 70% of the target, and given that these proposals go no further forward than 2006/08 it is not unreasonable to assume that further projects will come forward to allow the target to be met. However for this to happen a number of major barriers need to be overcome including:
    - Planning consent issues for projects, especially onshore wind farms, including dealing with concerns over wind farm planning saturation in some areas (visual intrusion, noise issues, reduction of house prices due to "industrialisation" etc);
    - Planning consent issues for the major new transmission lines required in Scotland;
    - Planning consent issues for strategic DNO reinforcements;
    - MOD and CAA concerns over radar interference;

- o Confidence amongst the financial community (assisted by the recent extension of the Renewable Obligation to 2015, but not tried and tested yet);
- o Successful and timely delivery of major transmission and distribution network reinforcements;
- o Confidence in the long-term technical performance of offshore wind projects.

There are especial uncertainties regarding CHP, and individual DNOs have approached this very differently, ranging from assuming zero CHP to assuming the Government's target for 2010 is delivered in full. The ILEX work assumed that 50% of the difference between current CHP and the target will be met, and some DNOs have then adjusted this to reflect potential projects in their areas. Connection applications for CHP were almost entirely absent from the DG-BPQs, thus DNOs are faced with uncertainty in developing projections.

Table 5-1 shows in summary form how each DNO has approached the derivation of future project volumes for both renewable and CHP DG and also gives our high level view of whether each forecast seems reasonable.

Table 5-1 – Methodologies used to forecast future DG volumes

DNO	Methodology for Future Forecast	MM/BPI Comments
Aquila	Internal estimates based on connections enquiries, some background research and an assumption that planning will get easier. No top-down assessment of likely generation, and limited reference to external sources. Wide range of possible future capacity provided.	Forecast: 69.7 – 309.0 MW Upper forecast likely to be on the high side in particular for small scale and domestic CHP. Forecasts are considered to be speculative.
EME	Trends in connection activity and a general view of published material and anecdotal evidence. Although considerable scenario planning has been done this does not appear to have been verified against external data.	Forecast: 865.0 MW The forecast is a significant increase on historical activity and may be on the high side, but is possible given the potential impact of onshore and offshore wind. Forecast is a considered view but would benefit from external verification.
EPN, LPN, and SPN	ILEX scenario work carried out nationally on behalf of the DNOs in which full achievement of the government renewables target and 50% achievement of the CHP target are assumed. EdF has extended the ILEX estimates to include waste to energy and potential maximum uptake values for each technology.	EPN Forecast: 807.8 MW Overall, we consider EPN's forecasts for future DG to be robust and reasonable. LPN Forecast: 335.4 MW Likely to be towards the upper end of credible scenarios for the LPN area where much depends on the uptake of CHP and a small number of high capacity waste to energy proposals.

		SPN Forecast: 472.0 MW SPN's forecast is 64% higher than the highest ILEX scenario. However, as the increase is based on actual activity, we consider SPN's approach to forecasting to be reasonable.
NEDL and YEDL	NEDL and YEDL have relied on studies undertaken by PB Power and OXERA, checked against Renewable Energy Assessment Projections commissioned by the Government, assuming more conducive commercial, regulatory and planning frameworks under which the targets for renewables and CHP would be achieved in full.	NEDL Forecast: 1152.9 MW YEDL Forecast: 1097.4 MW NEDL and YEDL have not had sufficient enquiries on which to base future estimates of DG and as a result, a large number of future projects have been included, which may not be realistic. Figures appear high relative to other DNOs and CHP assumptions in particular are likely to be a significant over estimate.
SEPD	Based on actual enquiries – not checked extensively against external sources.	Forecast: 248.0 MW Not particularly robust and probably on the high side in particular if CHP continues to be unattractive. SEPD area does not have high renewable energy potential as there are no local offshore wind development sites proposed in the 2005/10 period, nor are there any areas with significant onshore wind resource.
SHEPD	Based on projections from actual enquiries but not verified extensively against external sources.	Forecast: 866.7 MW While actual enquiries provide an excellent source of real project information, SHEPD do not appear to have accounted for potential changes to current momentum in project developments. The forecast may therefore be on the low side as current enquiries may be installed by 2006/7 leaving a potential gap in the forecast to 2010. However, planning issues may filter out a number of projects currently being considered.
SPD	Actual enquiries checked against government targets, work by OXERA and the Scottish Executive Resource Study. Forecast based on onshore wind and landfill gas only – no other technologies included and no CHP.	Forecast: 1437.0 MW Likely to be on the low side in particular if the economics of CHP improve markedly. Whilst we are confident in the SPD forecasts for the two specific technologies of onshore

		wind and landfill gas, it may be overly pessimistic to expect no other technologies to connect in the future period.
SPM	Based on actual enquiries and mostly onshore and offshore wind with a small amount of CHP and landfill.	Forecast: 987.0 MW The expected level of renewable activity is consistent with our expectations for the SPM area, which has a good renewable resource. However, as with SPD it may be overly pessimistic to expect only low levels of technologies other than wind power to connect in the future period.
UU	Three renewable energy scenarios combined with two CHP scenarios making six scenarios in total. Checked against external references and local government plans.	Forecast: 987.0 – 1530.0 MW A comprehensive and robust piece of work covering a wide range of possibilities; however UU does not comment on which of the scenarios it considers to be most likely. We would tend to agree with levels towards the higher end of the forecast range, but much depends on local planning authorities in sensitive areas.
WPD South Wales and South West.	ILEX scenario work carried out nationally on behalf of the DNOs with some modification for known local project enquiries. Assumes renewable energy targets are met and that 50% of the CHP target is met.	S West Forecast: 261.4 – 455.0 MW S Wales Forecast: 175.0 – 315.8 MW Three scenarios are considered but WPD does not comment on which of these it considers to be most likely. We would tend to agree with levels towards the higher end of the forecast range, but much depends on local planning authorities in sensitive areas.

Our view is that Government is committed to facilitating achievement of its renewable energy targets, but that the steps required to do this are demanding. Achievement of the target is therefore possible if the conditions set out above are satisfied but a more likely outcome is a shortfall against the target.

For CHP we see less evidence of commitment from Government and little interest from the industry. However the non-financial barriers are low and if the investment case for CHP improves markedly this position could change quite quickly. At this stage we see the ILEX scenario of achievement of 50% of the difference between the current level of CHP and the target as possible, but a more likely outcome is installed capacity less than 50% of the difference between current CHP and target. It should be noted that CHP penetration levels do not drive large changes in the level of strategic network reinforcement needed as most potential CHP is in urban areas where strategic reinforcement is not an issue and many projects do not export significant quantities of power to the network due to high on-site power consumption.

In assessing the impact of these uncertainties on network requirements it should be noted that insufficient network capacity is in itself a barrier and that under-investment in networks on the basis that targets will not be achieved may act as a disincentive to the DG industry. It is therefore arguably better for the balance of risk to be towards marginal over-investment to ensure sufficient capacity is available.

Having taken account of the information presented by the DNOs together with external information sources and our own views we believe that the aggregated project volumes across all DNOs, while derived from a range of forecasting approaches, are the best estimate at this stage for planning the network investment needed at the national level. There is an overall range between minimum and maximum projections (9,800MW to 10,900MW) that appears representative of genuine uncertainty, and there are variations in individual accuracies and ranges between DNOs, which Ofgem should approach with caution and use ranged scenarios in assessing impact on DNOs' costs. Some DNOs forecast a wide range of possibilities without giving firm opinions on what they see as most likely outcome, which to some extent is reflective of genuine local uncertainties. Where possible, we have provided opinion on the robustness of the forecasting technique employed by each DNO and the reasonableness of the forecast volumes of DG in the future period.

5.2 Strategic Reinforcement

Where there is a cluster of potential projects, connection to the network can be undertaken when firm projects come forward, leading to the provision of network on an incremental basis, or by considering all the likely projects in advance of firm connection applications leading to the provision of network in a more strategic way.

The features of these two approaches are compared in Table 5-2 below.

Table 5-2 – Comparison of Incremental vs. Strategic Approach

Incremental Basis	Strategic Basis
Work need only proceed when project is firm	Somebody needs to take the financial risk to invest ahead of need
Allocation of shared costs is straightforward	Allocation of costs can be complicated
Multiple planning consents required. Later projects may be more difficult and relationship of DNO and planning authorities may be harmed for future activity	Planning consent should be easier (though still difficult), and less likely to delay connection of the DGs as the work will tend to run ahead of many of the DGs' construction schedules
Overall cost/kW theoretically will be higher, but this is not always evidenced in practice	Overall cost/kW should be lower if all projects proceed. However, one or more of the projects used to justify the investment might not proceed, leading to inefficient investment
Network reinforced in piecemeal fashion	Resulting network should be more robust, leading to DG and demand customer benefits

EPN and UU commented during the DNO visit program that for their networks the difference in costs between the strategic approach and the incremental approach to network provision was likely to be low. Whilst EPN's view appears to be based on overall feel, UU has carried out an in-depth assessment of the likely reinforcement costs incurred by considering a range of pseudo-projects in areas identified as having significant potential. These pseudo-projects were then developed into fully designed schemes and the resulting incremental network developments compared to the likely reinforcements that would result from a strategic approach to accommodating the same projects. For UU's network the major reinforcements required proved to be very similar both in specification and cost for the two approaches, but the distribution of costs in the incremental approach led to very high costs falling on particular projects. Other DNOs have not undertaken a comparison of incremental and strategic development at the level of detail that UU has.

In some cases the initiation of significant strategic reinforcement prior to connection of multiple projects may well be too risky or difficult, for example in much of Scotland where distances and hence costs are likely to be very great, or in Cumbria where planning sensitivities are particularly high.

We have reviewed the DNOs' submissions regarding strategic reinforcement and our findings are summarised in Table 5-3.

Table 5-3 – Proposed Strategic Reinforcements

DNO	Proposed Strategic Reinforcements	MM/BPI Comments
Aquila	No proposed future strategic reinforcement expenditure.	Aquila's area does not have high renewable energy potential but there may be significant DG installed if the economics of CHP change significantly in the future period. Aquila is probably best to proceed on a project-by-project basis.
EME	£1.2m of strategic expenditure proposed on operations and control systems. No future strategic expenditure proposed on general infrastructure.	EME anticipates using the potential of Active Network Management before looking to significant strategic reinforcement to accommodate DG. The estimated costs for the systems to do this seem reasonable at this stage.
EPN, LPN, and SPN	Significant strategic reinforcement capital spend anticipated in EPN (£6.4m) and SPN (£5.9m) but unclear about location. No general infrastructure reinforcement proposed in LPN, but LPN anticipates £6.6m strategic spend of which £5.2m is on operations and control systems	The EPN and SPN areas have potential from offshore wind generation and the proposed levels of strategic spend seem reasonable. LPN's proposed spend on operations and control infrastructure appears high relative to others and may warrant further investigation.
NEDL and YEDL	No significant future strategic capital expenditure proposed. Both licensees anticipate significant operating expenditure increases due to DG.	The NEDL/YEDL approach appears reasonable.

SEPD	No future strategic reinforcements proposed.	SEPD is probably best placed by proceeding on a project-by-project basis.
SHEPD	SHEPD includes only a few strategic reinforcement schemes in its DG-BPQ with a number of large reinforcements associated with individual projects. £7m strategic capital expenditure is proposed for dynamic voltage support on remote island networks.	SHEPD's proposed capital expenditure appears reasonable. There will clearly need to be significant extension and thermal reinforcement of the SHEPD network but it is probably unwise to proceed with this in advance of firm projects due to the wide range of possible locations leading to incorrectly targeted spend. SHEPD expects some individual projects to carry significant reinforcement costs that could be treated as strategic reinforcement, e.g. sub sea cables. It is our view that more of these reinforcements could be considered as strategic reinforcements to allow the large amount of renewable generation to connect to SHEPD's network.
SPD	£14.3m strategic reinforcements proposed in the Borders and South West regions, and to finance general network reinforcement. (The originally submitted cost included work on the 132kV system which is defined as transmission in Scotland. If these costs were included, the total costs would be £82.8m).	SPD appears to have carried out significant work based on actual connections activity to identify the likely areas for strategic reinforcement. However the reinforcements identified will also assist in meeting load growth and so the costs attributable to DG appear high but the extent is difficult to evaluate.
SPM	£43.5m strategic reinforcements proposed mainly in the Mid Wales region, but with Denbigh Moor and Merseyside regions also included together with some general network reinforcement. (These costs would be £81.1m if the Mid Wales scheme included the total scheme cost instead of just the advancing cost.)	SPM appears to have carried out significant work based on actual connections activity to identify the likely areas for strategic reinforcement. However the proposed Mid-Wales reinforcement will also assist in meeting load growth as well as improving reliability and for this reason the costs attributed to DG appear to be high - see the alternative figure on the left.

UU	Although UU has not shown high strategic cost in their DG-BPQ submission it does expect significant reinforcement at 132kV to avoid export constraints at times of low local load. This may be best approached strategically rather than allocating high costs to particular projects. Significant DG capacity is already connected in Cumbria.	UU's strategy and costs appear reasonable.
WPD South Wales and South West.	Strategic infrastructure reinforcements proposed in South Wales (£2m) and South West (£1.5m).	The WPD licensees propose only modest strategic spend due perhaps to the uncertainty of project location. The balance between modest strategic spend and a project-by-project approach appears to be a good compromise.

The DNOs that have suggested a more strategic approach to reinforcement are SHEPD, SPD, SPM, and UU. Although both SHEPD and UU show only a low value for strategic Capex, both companies recognise the need for significant reinforcements that might best be considered strategically rather than be allocated directly to particular projects triggering incremental work. EPN and SPN have also included significant strategic costs of reinforcement but have been less specific about the geographical areas in which this might be spent. To a large extent, the levels of strategic reinforcement reflect potential for development of onshore and offshore wind energy. The Scottish Companies are already dealing with significant levels of wind farm connection applications, and in the cases of UU and SPM the companies are clearer than others in England and Wales about the likely geographical areas of renewables development. In EPN and SPN and to some extent EME there is clarity that significant development will occur but less certainty as to the location due to lower numbers of actual enquiries.

We believe that in each case where the DNO is proposing a strategic solution the proposed approach appears broadly reasonable in engineering terms. The DNOs concerned have in our view provided clear and well-argued reasons why particular areas of their networks would require reinforcement under the forecast scenarios they have developed. Although SPD and SPM cost projections for DG strategic reinforcement originally appeared high relative to other DNOs, SPD's costs included those on its 132kV assets and, in SPM's case, included the whole costs rather than the advancing costs for a reinforcement scheme. Appropriate adjustments have been made in the analysis to include only the relevant costs for these companies, and on this basis we believe overall national strategic reinforcement costs to be a reasonable estimate at this point in time. However, until proposals are developed in greater detail as project requirements firm up, the accuracies of cost estimates are likely to be fairly low, in our view around +/-20%, although this is based on overall feel rather than a detailed audit of individual costs, which is beyond the scope of this report.

It is evident from the figures provided that companies have taken a different approach to the split of cost between strategic reinforcement and shared costs in their DG-BPQ tables. SPD and SPM show their costs as high strategic costs with low shared asset costs for particular projects, whereas SHEPD and UU could potentially have included more costs as strategic reinforcement, (e.g. for major 132kV upgrades and remote island projects requiring sub sea cable reinforcements) rather than allocating these costs to shared assets for individual projects.

It is also possible that some DNOs might decide to adopt a hybrid approach, as appears to be the case for WPD, where a degree of strategic reinforcement is implemented together with an incremental approach where appropriate. DNOs might also choose to undertake all the necessary strategic planning and design at an early stage but only carry out the reinforcement work when it becomes necessary.

5.3 Capital Costs

In broad terms the technical solutions proposed for the shared assets of connection by the DNOs and the trend in cost drivers moving forward appear reasonable given the general state of development of distribution networks. The main driver for expenditure on shared assets in the historical and interim periods has been the need to manage increased fault levels, but in future the main drivers are expected to also include the need to increase network thermal capacity and to control voltage. In the historical and interim periods DNOs have largely been successful in accommodating DG on existing networks with occasional switchgear replacements where required for fault level management. In future this will need to change as networks need to be strengthened and extended due to the increasing requirement to connect generators in remote areas where networks are weak, and the requirement to manage voltage as the number of generator connections increases.

Unlike the sole-use assets of DG connection, the specification and installation of shared assets has to be carried out by the DNO and cannot be subjected to competitive quotation by the customer. Given this lack of competitive pressure it is possible that a degree of inefficiency and over recovery by the DNOs might exist in their quoted prices. In our investigations of comparative costs between DNOs and close examination of a small sample of selected individual schemes we found no evidence to suggest significant over pricing of shared assets by DNOs. However there were significant variations in forecast unit costs between DNOs, expressed as direct shared costs and strategic capital expenditure per unit of capacity of DG forecasted for the future period. Table 4 shows the range of unit costs of shared connection assets forecast by each DNO for the future period.

Table 5-4 – Units Costs of Shared Connection Assets

DNO	Unit Costs (£k/MW)	MM/BPI Comment
Industry Average	42	Ratio of aggregated national figures - see section 3.2
Aquila	44.3-89.0	Aquila estimates shared costs for the future period in the range of £13.7m to £27.5m including strategic capex. From the narrative provided, this cost range appears to relate entirely to the high scenario of 309 MW of future generation. This is in turn based upon a major contribution (110MW) from domestic CHP. This factor, together with the sweeping nature of the switchgear replacements proposed, supports our view that the high scenario is unlikely. Hence we believe Aquila's unit costs will be towards the lower end of their quoted range.
EME	13.7-58.9	The figures in Table 10 of the EME DG-BPQ reflect the plant mix corresponding to the central cost case and highest penetration level, and represent EME's best view of the DG situation in the future period. However, the cost ranges provided in Table 11 of the DG-BPQ relate to the central penetration case and do not match exactly with the scenario provided in Table 10 of the DG-BPQ. The high-level unit cost

		for shared assets and strategic capex of £14k/MW to £59k/MW using 865 MW of capacity in the future period are therefore likely to be under-estimates of the potential range of the unit cost.
EPN	51.4	The future high-level cost information for EPN indicates a shared asset cost of £35m for a capacity of 800 MW and strategic capex of £6.2m, which converts to a total unit cost of approximately £51k/MW. This figure is above the industry average due in part to the strategic costs included which are higher than other DNOs that do not have specific strategic reinforcement plans for the future period.
LPN	46.7	High-level costs for shared assets from the DG-BPQ are £9.2m for capacity of 334 MW. Strategic capex appears high at £6.4m; given that LPN has no plans for strategic reinforcement of its network. The largest contribution to strategic capex is from operation and control equipment. Unit cost for shared assets and strategic capex is above the industry average and above our expectation given the inherent stability of the LPN network.
SPN	37.3	SPN's estimate of strategic capex appears high at £5.6m. This includes £1m per year for general infrastructure, however no details regarding this expenditure are provided in the DG-BPQ narrative and SPN does not identify any hotspots for DG activity or discuss the need for strategic reinforcement. Unit cost for shared assets and strategic capex is comparable with the industry average.
NEDL	8.2	The high level cost information provided by NEDL indicates reinforcement costs of only £9.5m to allow connection of 1153 MW. NEDL has included no strategic capex in the future period. Total unit cost for shared assets is very low compared with the industry average. Our view is that costs have been under-estimated by NEDL and would benefit from further detailed bench-marking against industry average.
YEDL	10.3	YEDL's high-level estimate of reinforcement costs for the future period is £11.25m for capacity of 1097 MW. Their unit cost is similar to that for NEDL and considerably below the industry average. Like NEDL, YEDL has not forecasted any strategic capital expenditure in the future period.
SEPD	28.2-36.3	SEPD's high-level unit costs for the future period are based on shared asset costs of £7m to £9m and no strategic expenditure for a forecast capacity of 248 MW. The unit cost figure is below the industry average and appears reasonable given the low penetration of DG relative to other DNOs.
SHEPD	70.2-82.9	SHEPD's high-level unit costs for the future period are based on shared costs of £54m to £65m and strategic capex of £6.8m for an installed capacity of 867 MW. The resulting unit cost range is above the industry average, which is consistent with our expectations given the large number of projects wishing to connect to remote parts of SHEPD's network. Particularly high

		costs appear where undersea cable installation or reinforcement is required for island-based projects.
SPD	13.6	It is consistent with our expectations that SPD's unit cost would be above the industry average, were the 132kV costs to be included (i.e. at £61.2k/MW) given the significant penetration of DG in the SPD network and the associated requirement for reinforcement. However, as the 132kV system is defined as transmission in Scotland, it is excluded from the distribution cost. The resulting unit cost is lower than the industry average.
SPM	44.1	The high-level unit cost for shared assets and strategic investment in the SPM licensed area is comparable with the industry average (and would be significantly higher, at £82.2k/MW, if the whole scheme costs instead of only the advancing cost of the Mid-Wales scheme were included). SPM has included no shared asset costs and £43.5m of strategic costs for the various areas identified, but we consider it to be unlikely in reality that all reinforcement will be strategic rather than project specific. A much more detailed examination beyond the scope of this high level assessment would be needed to further assess the allocation of these costs.
UU	28.2-43.9	High-level unit costs for shared assets and strategic investment in UU's area for the future period are based on the six scenarios considered by UU. Unit costs are based on minimum cost for minimum capacity and maximum cost for maximum capacity and other combinations of capacity and cost ranges result in slightly lower and higher unit costs respectively. The range of unit costs for UU is comparable with the industry average but seems conservative given the need for significant reinforcement in the future period, particularly in the Cumbria region. However, we acknowledge that UU appears to have performed the most work in determining cost estimates through its modelling approach.
WPD-South Wales	23.0-74.5	The wide range of the figures for both WPD licensees are distributed almost evenly about the industry average, with the maximum unit cost appearing to be on the high side. Total strategic costs are forecast at £1.9m for the future period, which appears low compared to other DNOs.
WPD-South West	22.2-74.3	See note for WPD South Wales. Strategic capex is forecast at £1.4m for the future period, which appears low compared to other DNOs.

The average unit costs for each DNO exhibit a wide spread and the ratio of greatest to least estimates is over 10:1 (£8.2k/MW up to £89k/MW). The extent to which this spread can be understood and justified in terms of real differences between DNOs is discussed in the following paragraphs.

Where Companies have considered a range of future DG scenarios this has resulted in a range of future unit costs with the higher costs generally being associated with scenarios requiring higher levels of reinforcement. SHEPD show unit costs towards the higher end of the range, which seems logical since future projects are expected to occur in remote areas with only weak existing networks, and sometimes requiring unusually high cost connection work (e.g. undersea cables) due to the specific geographic characteristics. SPD, SPM and UU, the other companies expecting major strategic reinforcement, have lower unit costs (assuming only the advancing cost of the Mid-Wales was included for SPM). This may reflect a greater degree of clustering whereby individual reinforcements benefit greater numbers of projects and/or demands as well as generators. In SPD's case, an additional factor contributing to the lower costs is that its distribution network does not include 132kV (which is defined as transmission in Scotland). At the high end of the range are the upper limit costs of the WPD companies whose costs also show a wide spread. The WPD area has moderate DG potential but the upper limit costs appear high relative to other companies facing similar challenges.

Aquila has derived upper limit costs that appear high relative to others based on an apparent worst-case in which large-scale switchgear replacements are required to manage fault levels at major substations, and in our view have not yet been able to provide convincing evidence of the necessity for this. Compared to the average value of £42k/MW from the high-level information provided for the industry, Aquila's range of estimates appears on the high side. In addition, the expected cause of shared assets is predominantly large scale replacement of switchgear which highlights a possible lack of detailed investigation into the causes for reinforcement on the part of Aquila. Therefore our view is that the lower end of their unit cost range is likely to be more realistic.

Both EPN and EME in their upper bound scenarios anticipate unit costs exceeding £50k/MW. Both Companies have significant potential for DG but there appears to be less clarity about location of likely connections and on whether offshore wind connections will be made to the distribution network or directly to the transmission system. LPN's forecast unit cost is derived mainly from a single major energy from waste site that appears broadly typical of its type.

SPN's forecast unit cost appears lower than others and this may be in part due to the existence of an historically strong network in the area. SEPD forecast figures appear reasonable although the potential for renewable energy in the area is low relative to others due to the absence of proposed local offshore wind developments in the 2005/10 period and the lack of significant onshore wind resource.

In contrast to the DNOs where major strategic reinforcements have been anticipated, NEDL and YEDL appear to anticipate connecting DG with little need for significant shared cost in the period to 2010, and are the only DNOs to list future direct cost savings on shared assets. The majority of DG applications to date have been large-scale CHP connections, and these Companies have historically strong networks in areas where heavy industries have in recent decades been in decline. Based on our understanding of the NEDL and YEDL networks, it seems reasonable that these DNOs will be able to continue to connect DG without the need to provide significant new distribution network for some time to come. In addition there is reason to believe that provision of new generation in the North East may restore some of the voltage control flexibility lost on closure of coal fired generating capacity at Blyth. However, we believe that the NEDL/YEDL figures of £8.2k and £10.3k per MW for future shared costs of connection may be a significant underestimate in particular if future DG connections are concentrated in rural areas where the network is weak.

Thus in reviewing the spread of costs for different DNOs, we can find apparent reasons for the pattern that has emerged. However the uncertainties in the data do not allow us to form firm views. Given the uncertainty in the future costs, and the lack of detailed information in some DNOs, we believe that the most pragmatic approach is to take an overall average of the high level unit costs across all the DNOs as a reasonable view of the future DG cost. Exceptions could be made for DNOs who have justifiable and robust data. It is noteworthy that the costs are driven mainly by the existing network and the expected volume of renewable connections, and not by issues such as labour cost variations nationally. We would expect factors such as this to be relevant, but to be masked in the available data. In addition there may be scope for the application of new technology and techniques to reduce DG connection costs and this is being examined in separate work on the potential for Registered Power Zones (RPZ) and Innovation Funding Incentives (IFI) for DNOs.

5.4 Operation and Maintenance Costs

DNOs have historically based the O&M contribution in DG connection costs on 2.25% of connection capital cost per annum over a 20 year notional lifetime brought forward into a one-off charge using the prevailing allowed cost of capital. At the current cost of capital of 6.5%, this results in an O&M price of around 25% of the direct cost of connection being added as part of the overall connection charge. The calculation procedure is based on a modelling approach developed by the Electricity Association (formerly the Electricity Council) over 20 years ago[1]. Using this broad approach, estimates of the long run incremental costs of the system have been derived using a stylised model of the distribution network. This is typically constructed to reflect the specific changes in network design required to meet an additional 500MW of load. Some DNOs commented that this is now in need of revision.

There are a number of factors taken into account by DNOs in setting the level of the O&M component of DG connection charges including:

- the proportion of network O&M costs and general company overheads fairly attributable to DG connections - DNOs generally use the ratio of average annual operational costs to overall capital value of network in most DG connection cases, but also calculate specific O&M costs where appropriate;
- whether differing percentage rates should be applied to sole-use and shared-use components of assets;
- the number of future years life of the connection over which to include O&M charges - most DNOs generally use 20 years but occasionally other periods such as 10 or 15 years are used if deemed by the DNO to be appropriate;
- the level of discount to be applied to O&M costs in future years so as to bring forward future costs into a present charge - most DNOs apply a discount of around 6.5%, which is commensurate with their regulated figure for cost of capital.

The differing cost bases and approaches of the DNOs have led to differing O&M percentage in DG connection charges being applied for different projects and in different DNO areas.

There are good reasons to suggest that O&M costs have fallen in recent years. Introduction of IT systems have considerably reduced control costs and there have been significant improvements in the efficiency of fault location and repair. The general move towards maintenance based on plant condition monitoring rather than on a time based program has reduced maintenance costs and DNOs have made significant reductions in corporate overheads.

The modern distribution plant used to effect connections today requires less maintenance and is more reliable than the average for typical plant items on the network, many of which are over 40 years old, and so it seems excessive to charge O&M at the average rate. In addition it seems incorrect to charge O&M on shared assets where older assets are simply replaced with new plant requiring similar or less maintenance.

[1] The basis for cost reflective retail tariffs in England and Wales, T A Boley and G J Fowler, IEE Third International Conference on metering, Apparatus and Tariffs for electricity supply, London 1977.

A number of DNOs have already moved away from the historic values of around 25% and now charge a lower percentage rate for O&M. NEDL and YEDL have moved from 2.25% per annum to 0.98% per annum (capitalised to around 12%), UU has moved to 14% and WPD is set to move away from a percentage basis to individual O&M calculations for each connection. In our view a level of 14% (equivalent to 1.3% per annum over 20 years) seems reasonable given the factors described above.

An additional factor on which there is little experience at present is the cost of active management of the network. EME reports anecdotal evidence suggesting that costs of active management have turned out to be higher than anticipated and as a result list a figure of 35% for O&M in the future period. The introduction of active management techniques may result in the reduction of connection costs as it may prove possible to connect more DG before triggering major reinforcement, but there will clearly be some extra operating costs associated with active management and these may represent a higher percentage of the reduced capital cost of connection. Further work is needed to provide informed estimates of what level of extra costs might efficiently be incurred.

In addition to the variations in percentage allowance for O&M in DG connection costs there are variations in the estimates for strategic Opex in the future period and these are shown in Table 5-5 below.

Table 5-5 – Breakdown of Future Strategic Opex Cost Estimates

	Operations & Control	Other	Planning & Design	Research & Development	Grand Total
Aquila					£0.10
EME	£0.41	£0.47	£0.68	£0.18	£1.75
EPN	£5.03	£0.35	£1.73	£0.36	£7.47
SHEPD	£0.14		£0.10	£0.10	£0.33
LPN	£0.38	£0.08	£0.43	£0.00	£0.90
SPM	£0.16			£0.53	£0.68
NEDL		£5.27		£1.26	£6.53
SEPD					£0.00
SPD	£0.16			£0.53	£0.68
SPN	£1.08	£0.35	£0.76	£0.15	£2.33
WPD South Wales			£0.27		£0.27
WPD South West			£0.25		£0.25
UU	£2.22	£1.25		£1.67	£5.13
YEDL		£5.07		£1.26	£6.33
Totals	**£9.58**	**£12.83**	**£4.22**	**£6.04**	**£32.77**

DNOs argue that additional functionality will be required in control rooms, ranging from more sophisticated computer systems to additional control engineers. It seems reasonable to us to conclude that as DG penetration increases so will the associated operational complexities and extent of system monitoring, particularly if the system becomes more actively managed. It is also likely that there will be a requirement to balance demand within parts of the network and manage other technical parameters such as voltage and security.

There is an expectation amongst DNOs that as penetration of DG increases the stresses on network assets are likely to increase and this may tend to increase the failure rate of assets, if only because existing weak points are more likely to develop into faults. In addition the presence of significant DG will increase the complexities and hence costs of arranging network outages. Some DNOs have indicated that increasing the integration of DG into networks and moving away from the 'fit and forget' approach will increase the complexity and extent of network design studies associated with network reinforcement and compliance monitoring. This will in turn lead to the requirement for increased numbers of highly-skilled staff to undertake these activities. In addition the deployment of innovative control and management systems on networks will be a significant change in the complexity of current control and protection systems, and this will lead to the requirement for a more highly-skilled workforce in the field to install, repair and maintain such equipment.

We therefore believe it is reasonable for DNOs to include a component of additional strategic Opex spend due to projected increases in DG penetration. However there is considerable variation across the expenditure categories set out in Table 5-5 and also across DNOs estimated total costs. It is evident that some DNOs have not allocated costs carefully to the appropriate categories and others appear to have overlooked that extra costs may be incurred in particular categories. It may also be the case that some DNOs consider extra costs in these areas to be small and therefore not significant enough to warrant individual attention. DNO thinking is clearly not well developed in this area and therefore cannot be challenged in detail.

However, in our view it would be reasonable to expect that strategic DNO Opex increases due to DG in the Operations & Control, and Planning & Design areas would be largely driven by levels of penetration of DG and by DNO size. It also seems likely that a relatively constant component of R&D would be needed across all DNOs to enable new technologies and practices to be adopted at an early stage. The need for significant R&D expenditure is probably best considered in the context of other potential mechanisms such as the proposed RPZ and IFI mechanisms.

Although the DNO thinking is not well developed on strategic Opex increases due to DG, and the figures put forward are clearly only rough estimates, our high level view is that some licensees may have over estimated (e.g. EPN, NEDL/YEDL, and possibly UU) and other licensees (e.g. SHEPD, Aquila, and SEPD) appear to have under estimated or overlooked cost increases in this area. The overall national total estimate may therefore be quite reasonable.

5.5 Quality of Supply

Some DNOs have commented that the presence of DG has reduced the quality of supply in the locality of the connections. SPN produced a short piece of monitoring work that demonstrated increased incidence of faults on a particular feeder over a number of years following the installation of DG, although the cause of the faults was not examined in detail. NEDL and YEDL commented that they expect quality of supply to deteriorate in the short term simply because of the presence of more equipment subject to the risk of failure as numbers of DG connections increases. The intermittency of DG operation may in certain areas give rise to an increased incidence of rapid local power flow variations thus putting additional physical stresses on ageing network assets. In addition the presence of DG may give rise to changes in the thermal stresses on existing transformers and cabling that have been operating satisfactorily within a particular range for many decades. These factors, coupled with the lack of fault ride-through of many DG connections and the absence of agreed safe arrangements for island operation, suggest that DNOs may not in the short-term experience the potential benefits to quality of supply that local generation may eventually provide.

Whilst some DNOs are uncommitted on whether DG will have an effect on quality of supply, those who expressed a view felt that there would be deterioration as DG levels increase and seemed to have a tendency to emphasise all the problems. However, we believe that DNOs should be able to make appropriate allowance for continued improvements in levels of CI and CML as DG penetration levels increase through good organisation with proper and timely planning.

5.6 Relationships between DNOs and DG Developers

DNOs have a range of approaches to DG projects wishing to connect to their networks, and this is evident even between individual DNOs facing similar levels of DG volumes and network constraints. These approaches range from resolving shared problems to facilitate connection leading to a positive relationship, to applying procedure rigidly, which tends to make the resolution of issues more difficult thus creating barriers. Approach to connections seems to be a function of the business culture existing within the DNO. There are also issues of inconsistent treatment of costs, notably for O&M, and the savings credited to projects for the re-use of displaced equipment and for network betterment. In our view there is scope for clearer guidelines to ensure greater consistency.

In dealing with developers of DG projects, DNOs face a number of challenges, particularly related to uncertainty. Connection applications and discussions for a project can proceed sporadically over many years, meaning that DNOs struggle to have a solid view of which projects are likely to proceed in a given part of the network. Their local knowledge and contacts help, but a DNO is often in the dark much of the time. In areas of good resource or network capacity, DNOs may receive multiple requests for connections to the same part of the network, which requires careful and transparent management.

In our view there is room for improvement of information flow and flexibility of interaction between DNOs and developers. DNOs could for example adopt a similar approach to WPD that has published high level network layouts on its website. In addition a published clear point of contact for DG developers in each DNO area would be helpful. On the developers' side we recommend that a mechanism be introduced whereby connection applicants are encouraged to provide DNOs with quarterly progress reports on non-connection aspects of their project. This could be a standard sheet giving details of key areas of development, for example permits, financing, fuel supply, construction contracts, level of development priority, changes in output or technology etc.