QUANTIFYING THE SYSTEM COSTS OF ADDITIONAL RENEWABLES IN 2020

A report to the Department of Trade & Industry

In association with

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EXECUTIVE SUMMARY

This report quantifies the additional system costs that are likely to be incurred if the volume of renewables in Great Britain were to increase from an assumed level of 10% of demand from 2010 onwards, to 20% or 30% of demand by 2020. The systems costs considered comprise:

- reinforcing and managing the transmission systems;
- the impact on transmission losses;
- reinforcing and managing the distribution networks; and
- balancing energy generation and demand, including:
  - short-term response and reserve; and
  - long-term system security.

This study specifically excludes the capital and operating costs of renewable generation and the costs of connecting these generators to the distribution or transmission systems. We refer to these costs as "project costs" to distinguish them from system costs. The study has not considered the likelihood or otherwise of meeting current or new targets, but has taken these as given. This study does not propose an allocation of the identified system costs or presuppose any particular charging mechanism, trading arrangements or renewables support programmes.

The report is based on a study undertaken by ILEX Energy Consulting and Professor Goran Strbac of the University of Manchester Institute of Science and Technology (UMIST) for the DTI. The study used scenario analysis to investigate the plausible range of system costs in 2020 under various combinations of demand, renewable technology mix and volumes of renewable generation. This report presents the additional system costs for a market with 20% or 30% renewables over and above the costs that would be incurred for a market with 10% renewables.

In all the scenarios we investigated, we found that extending renewable generation to 20% or 30% of demand by 2020 would increase system costs. Moving from a market with 10% renewables, as envisaged from 2010 onwards, to a market with 20% renewables, may increase system costs by between approximately £150m and £400m per annum. Extending renewables from 20% to 30% of demand would increase costs by around a further £200m to £500m per annum. However, the extent of the additional system costs varies considerably, primarily driven by the technology and location of renewable plant. These extra costs may be compared with the wholesale value of all electricity generated in 2020, of some £9 billion[i] per annum. All monetary values presented in this report are in Pounds Sterling, expressed in real terms in April 2002 prices.

The calculation of system costs is complex and projecting these costs for 2020 is subject to a great degree of uncertainty. The values presented in this report should therefore be taken as indicative of the order of magnitude of the likely costs. Although we have presented figures as calculated by our modelling, the reader should be aware of the degree of uncertainty involved in their derivation.

Table 1 – Range of additional annual system costs (real 2002 prices)

Renewables penetration		Annualised / annual costs (£m)	Cost per unit of: all generation (£/MWh)	Cost per unit of: additional renewable generation (£/MWh)
20%	Lowest cost	143	0.3	3.3
	Highest cost	398	0.9	9.3
30%	Lowest cost	325	0.8	3.8
	Highest cost	921	2.2	10.8

Table 1 illustrates the range of system costs on an annual and unit basis. The unit costs illustrate the annual cost spread over all generation on the system and spread over the additional renewable generation only.

Lowest system costs

If the additional renewable generation required to meet higher targets came from an equal mix of predictable baseload plant, such as the biomass technologies located throughout Great Britain, and the closer-to-market interruptible generators, such as wind, dispersed around England and Wales, then the additional system costs would be £143m per annum for 20% renewables and £325m per annum for 30% renewables.

Highest system costs

Alternatively, if the additional renewable generation required to meet 20% or 30% of demand were met entirely from intermittent generation, such as wind, located predominantly in Scotland and northern England, then the costs would be £398m or £921m per annum, respectively.

System cost drivers

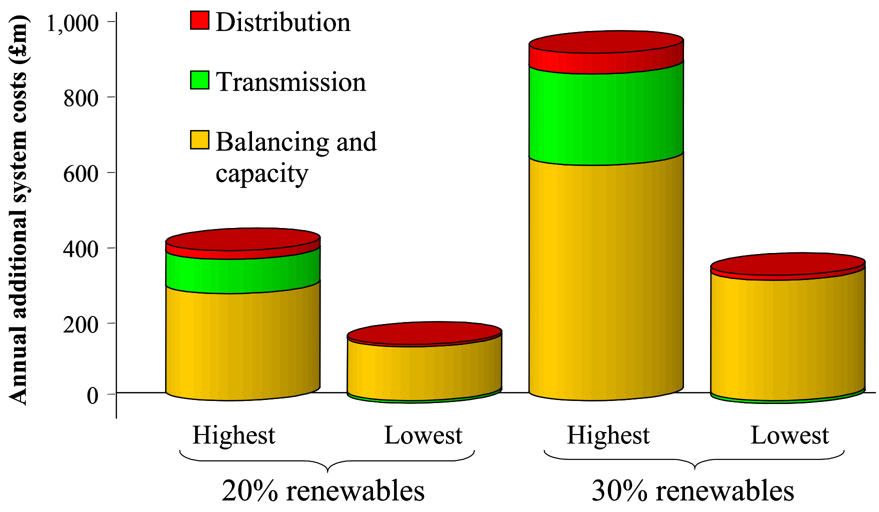
Figure 1 and Table 2 present the breakdown of additional annual system costs between the three elements examined – balancing and capacity, transmission and distribution. It can be seen that balancing and capacity costs, principally the cost of maintaining system security, dominate all other costs. These costs arise because of the intermittency of many renewable technologies, in particular wind, which represents a large proportion of Great Britain's renewable resource.

Table 2 – Additional annual system costs broken down by source (£m, 2002 prices)

Renewables penetration		Balancing and capacity costs	Transmission costs	Distribution costs
20%	Lowest cost	143	-6	6
	Highest cost	284	91	23
30%	Lowest cost	319	-8	13
	Highest cost	624	242	55

In the lowest cost scenarios, the additional renewables reduce transmission losses to the extent that total transmission costs are less than for a system with 10% renewables.

Figure 1 – Breakdown of annual system costs in highest and lowest cost cases



Intermittency

The intermittency of renewables is the single largest driver of system costs, increasing the costs of capacity, synchronised reserve, response and wind curtailment costs.

- Capacity costs relate to the limited contribution that wind can make to system security, because of the correlation of output across generators and the risk of low wind speeds across the whole country for prolonged periods. In the values presented above, based upon statistical analysis we have carried out, wind makes some contribution to capacity at peak, but this contribution is significantly less than for equivalent conventional generation or non-intermittent renewables. Our calculations of capacity costs assume that the additional capacity required to maintain system security is provided by open-cycle gas turbine (OCGT) plant. New technological developments in storage, fuel cells or load management by 2020 may reduce the cost of providing this additional capacity. However, it is often argued that wind may be unable to contribute to system security at all, because of the risk of periods with hardly any wind at times close to maximum system demand. Although we found no evidence for this being a significant risk in the one year of generation data we studied, we have run a sensitivity which suggests that if wind were considered to have zero capacity value, this could increase the balancing and capacity costs reported in Table 2 by approximately 30%.

- Synchronised reserve and response are related to the balancing of generation and demand over seconds and minutes. Intermittency of wind increases the variance of generation patterns considerably, requiring greater reserve and response to be held on the system.
- Energy curtailment costs are incurred during periods of low demand, particularly on summer non-business days, where inflexible generation can exceed the demand. On windy summer days, wind generation may need to be constrained-off the system to avoid over-generation relative to demand.

Location of renewables

The location of renewable generation, like conventional generation, can have a significant effect on transmission, and to a lesser extent, distribution costs.

Transmission

Transmission costs have historically been driven by a north-south flow from thermal generators located predominantly in the north, to demand in the south. With significant wind resources in Scotland and off the North West and North East of England and North Wales coasts, it is possible to envisage scenarios where this pattern of flows endures, despite the retirement of many of the existing conventional stations, thereby increasing the requirement for transmission reinforcement and the level of transmission losses.

Alternatively, if the additional renewables were developed across Great Britain and included the offshore wind resources around the England and Wales coast, as envisaged in the lowest cost scenario described above, then transmission reinforcement costs could be negligible and transmission losses might be reduced.

Distribution

The principal distribution system costs of connecting significant levels of renewable generation are the capital costs associated with reinforcement of the network. The study confirms that the costs of reinforcing the distribution networks will generally increase with higher penetrations of renewable generation and that distribution system reinforcement costs are driven by concentrations of generation capacity. The study shows that costs may increase significantly where there is a high concentration of smaller scale generation deployed in a particular region – such as onshore wind turbines in the North of Scotland – or where a high number of generation schemes of the same size are concentrated on one particular voltage level.

The analysis suggests that a regime of advanced, coordinated management of network voltages could deliver significant reinforcement savings – especially in areas of high generation density. Also, the circuit reinforcement costs of connecting generation at very high voltages can be a significant contributor to overall costs.

Extent of renewable deployment

System costs under a 30% renewables scenario are significantly greater than under a 20% scenario. From Table 1, it can be seen that costs per unit of additional renewable generation are 15% higher for 30% penetration. This is observed across generation and transmission costs. It follows that the cost curve is rising, that is to say, the incremental system cost in moving from 20% to 30% is greater than that of moving from 10% to 20%.

Experience in Denmark

Our study also includes a brief survey of Danish experience since wind generation has reached a significant proportion of total generation in that country. We found that electricity trade with neighbouring countries has been a significant tool for managing the intermittency of wind generation in Denmark. The Danish system has much larger links with neighbouring countries, in relation to its total capacity, than is the case for Great Britain.

We have not investigated the commercial values of the extra trade in electricity arising from managing intermittency and have therefore not been able to form a view on the extent of costs which intermittent generation may have imposed on the Danish system. However, it is clear that in Denmark the impact of intermittent generation is managed in a way that would not be feasible in the UK without a fundamental change in the degree of interconnection with wider European electricity networks.

[i] The value of wholesale electricity in 2020 has been estimated to be £9 billion per annum. This is based on total generation of 394TWh to 427TWh, and a wholesale price of £22/MWh in 2020 (in 2002 prices), as assumed for this study. This value excludes ROCs and transmission and distribution use of system charges, and so it is not indicative of the retail value of electricity to final customers.

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1. INTRODUCTION

What this report is about…

1.1 This report describes a study undertaken for the DTI by ILEX Energy Consulting and Professor Goran Strbac of the University of Manchester Institute of Science and Technology (UMIST). The study quantifies the additional system costs that are likely to be incurred if the volume of renewables in Great Britain were to be extended from the current target of 10% of demand from 2010 onwards, to 20% or 30% of demand by 2020. The study was concerned only with the additional costs of reinforcing and managing the transmission and distribution systems and with balancing energy generation and demand (through both short-term reserve and longer-term capacity).

1.2 Additional system costs might be incurred as renewable generation is increased to 20% or 30% of demand because:

- the location of new renewable generation, either connected directly to the transmission system or embedded within local distribution systems, is different from that of existing, mainly conventional, transmission-connected generation;
- intermittent generation such as wind, wave or tidal power may require additional balancing actions by the system operator or may not be able to contribute to system security by providing firm reserve; and
- inflexible generators or small diverse generators, such as photovoltaics or some biomass generators, may not be able to provide system services such as frequency support that is presently provided by conventional generation.

1.3 There was no presumption that system costs under a high renewables scenario would necessarily be higher than under a low renewables scenario, so additional system costs could be negative as well as positive.

…and what the report is not about

1.4 This study specifically excludes the costs of developing renewables, and the connection costs of renewable generators to the distribution or transmission systems. The study has not considered the likelihood or otherwise of meeting current or new targets, but has taken these as given. This study does not propose an allocation of the identified system costs or presuppose any particular charging mechanism, trading arrangements or renewables support programmes.

1.5 This report presents scenarios for the future deployment of renewables, discussed in detail in Section 3, that were designed not as predictions of the likely development of new renewables, but as relatively extreme scenarios in order to test the likely maximum and minimum ranges of the additional system costs.

Background

1.6 The PIU (Performance and Innovation Unit) Energy Review[1] proposed that the current target for electricity supplied coming from renewable generation should rise from 10% by 2010 to 20% by 2020. The Government is now drafting an Energy White Paper to be published early in 2003, which will set out its approach to future energy policy.

1.7 To inform the White Paper, the Government has been undertaking research in a number of areas. This report, prepared by ILEX Energy Consulting and Goran Strbac (hereafter collectively referred to as ILEX), documents the findings of a project undertaken to establish order of magnitude estimates of the system costs of expanding the quantity of renewable generation in Great Britain in the period after 2010. The original terms of reference for this study are attached at Annex G.

1.8 The overall aims were to establish the plausible range of the additional systems costs of 20% and 30% of renewables by 2020 over baselines in which renewables remained at 10% of demand. In so doing, the study defined system costs as:

- provision of system security and system balancing;
- transmission system reinforcement, constraint management and so on;
- distribution system reinforcement and management.

1.9 This study has tackled this question by drawing a distinction between the *project* costs of developing and operating renewables (which we have not considered), and the *system* costs associated with them under a number of scenarios for wider renewables deployment. The study developed a broad range of scenarios covering the volume of renewable generation, the renewable technology employed and its location. By comparing system costs in these scenarios with compatible baseline scenarios, where renewables remained at 10% of demand, the study was able to determine the additional system costs related to renewable generation of 20% or 30% of demand.

Consultation and collaboration

1.10 In undertaking this study, ILEX has benefited from the assistance of a large number of individuals from within the industry and government departments. ILEX is grateful for all the assistance it has received in undertaking this work.

1.11 The project reported to a Government Steering Group comprising representatives of DTI, DEFRA, the Scottish Executive and independent experts from Imperial College, London.

1.12 ILEX established an Industry Review Group comprising representatives of the three transmission companies, (NGC, Scottish Power and Scottish and Southern

1 The PIU (Performance and Innovation Unit) Energy Review (February 2002)

Energy), and a number of the distribution network operators. Members shared their valuable experience gained from similar studies and commented on this project's assumptions and methodologies. The assumptions and approach adopted reflect the consensus of the group but the results presented in this study may not necessarily reflect the opinions of individual members of the review group or the companies they represent.

1.13 ILEX also convened a Distribution Review Group by for the purposes of this study to discuss and agree both the methodology adopted in the assessment of distribution costs and the key assumptions upon which the analysis was based. A wide range of GB Distribution Network Operators (DNOs) were represented in the group with only three of the fourteen DNO areas not directly represented. All of the geographic areas identified as generally having significant renewable resource potential were represented within the group.

1.14 ILEX also benefited from the assistance of a wider body of contributors throughout the industry.

1.15 All those who contributed to the project are listed in Annex A.

Convention

1.16 All monetary values presented in this report are in Pounds Sterling, expressed in real terms in April 2002 prices.

1.17 System costs per unit are expressed variously in this report as per unit of total generation, per unit of additional renewable generation (over the 10% baseline) and as per unit of additional wind generation (over the wind generation in the baseline). Unit costs are expressed as £/MWh. To convert to unit costs expressed as p/kWh, divide by factor of ten, i.e. £2.20/MWh is equivalent to 0.22p/kWh.

Outline of the report

1.18 In Section 2, we present the high level results, quantifying the additional system costs, and describe the key cost drivers and the issues arising from this study. All subsequent sections provide fuller descriptions of our methodology, assumptions and findings for those who are interested in understanding the detail of the various aspects of the project.

1.19 Section 3 provides a description of our methodology and common assumptions.

1.20 The subsequent sections provide details of the specific assumptions, approach and results for each of the three core cost areas:

- Section 4 relates to generation costs;
- Section 5 to transmission costs; and
- Section 6 to distribution costs.

Each of these sections concludes with a description of the cost drivers in that area.

1.21 Section 7 provides a summary of Danish experience with relatively high levels of renewable generation. It had been suggested that Denmark might be able to provide insight into system cost issues, after reports that it had curtailed support for renewable projects because of system problems associated with its extensive investment in wind generation.

1.22 In the Annexes of this report we:

- acknowledge the contributions and assistance we have received in undertaking this study;
- provide a detailed set of assumptions and results for each of the baselines and scenarios;
- provide a summary of the assumed location of new renewable generating capacity;
- undertake a worked example of the capacity cost calculation;
- summarise transmission system reinforcements;
- provide further details of the distribution system analysis; and
- attach a copy of the original terms of reference for this study.

2. THE SYSTEM COSTS OF ADDITIONAL RENEWABLES

2.1 In this section we present the high level results of the study, commenting on the key cost drivers and identifying the issues that arise from the findings. The system costs in relation to transmission and distribution are reinforcement related, and as such are capital expenditure on assets that may be expected to remain in place for 40 years. In contrast, generation costs related to balancing are annual costs and those related to system security are capital costs of generation assets. To compare costs across these categories we have annualised[2] costs and presented them in this section on a total and per unit basis. The additional capital expenditure on transmission and distribution reinforcement is discussed in Sections 5 and 6 respectively.

2.2 In all the scenarios we investigated, extending renewable generation to 20% or 30% of demand by 2020 would increase system costs. However, the extent of these additional system costs varied considerably, with the technology and location of plant being the major drivers and the extent of renewable generation also a key factor.

2.3 The calculation of system costs is complex, and projecting these costs for 2020 is subject to a great degree of uncertainty. The values presented in this report should therefore be taken as indicative of the order of magnitude of the likely costs. Although we have presented figures as calculated by our modelling, the reader should be aware of the degree of uncertainty involved in their derivation.

Scenario analysis

2.4 The study has considered two alternative levels of demand in 2020, a business as usual, *high* demand case, where peak demand and the annual volume of demand continue to grow at a rate of 0.8%, and a *low* demand case, where demand is held constant beyond 2010. The 2020 renewables targets are 8% greater in the high demand case than the low demand case. In our baselines, demand is met by a combination of conventional generation (some existing plant and a large volume of new-build plant, to replace retired coal and nuclear generators), CHP and renewable generation in line with the Government's 10GW and 10% targets. In these baselines, we assumed that the only nuclear generation remaining open in 2020 was Sizewell B. However, we also developed a *Nuclear baseline* in which we assumed that all existing AGR stations remained in operation and that 3000MW of additional nuclear plant was commissioned between 2015 and 2020. In the renewable scenarios, we extend the volume of renewable generation to 20% and 30% of the identified demand.

[2] Our approach to annualisation is discussed further in Section 3.

2.5 We developed three alternative views for the technology and location of the additional new renewables to meet 20% or 30% of demand. These combinations were designed to explore the maximum and minimum generation, transmission and distribution costs. These scenarios for new renewable generation beyond 2010 are summarised in Table 3 and described in detail in Section 3. Figure 2 illustrates the capacity mix in each scenario for 20% renewable penetration.

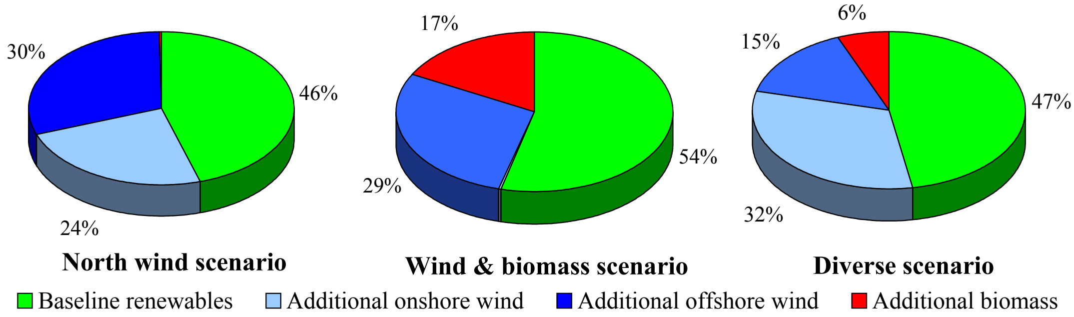
Table 3 – Additional renewable technology and location scenarios

Scenario name	Type and location of additional renewable generation
North Wind	Equal volumes of onshore and offshore wind. Onshore wind located predominantly in Scotland and offshore wind predominantly in northern and eastern England.
Wind & Biomass	Equal volumes of offshore wind generation and biomass generation. Offshore wind located around the coast of England and Wales and biomass throughout Great Britain.
Diverse	Half of new renewable generation from offshore wind, 30% of generation from onshore wind and the remaining 20% from biomass. All technologies located throughout Great Britain.

2.6 We have considered only two key technology types, wind and biomass. This simplistic assumption does not represent a belief that only these two technologies will be developed, but that these technologies reflect two extremes – intermittency and unpredictability on the part of wind and baseload predictability on the part of biomass. By using these two technologies as examples, we believe we have spanned the range of likely system costs.

2.7 Our calculations of system costs were run for the three technology/location scenarios at 20% and 30% deployment levels in both the low and high demand scenarios. – some twelve renewables scenarios in total. A further scenario was also run, combining the *North Wind* renewables with an increased volume of nuclear generation, as described for the *Nuclear baseline* in paragraph 2.4. Each of these scenarios was compared to the base case where renewables remained at the 2010 10% target, to determine the additional system costs of the higher renewables deployment. Separate base cases were developed for high and low demand and for the high nuclear scenario.

Figure 2 – Capacity by technology in 20% renewables scenarios with high demand



Note: The additional capacity of renewables is substantially greater in scenarios with greater wind generation, as this technology has a lower load factor than biomass generators.

Total additional system costs

2.8 Additional system costs range from £150m per annum to £400m for 20% renewable penetration, depending on the mix of renewable technologies and the location of those plant. Theses costs are equivalent to £0.3/MWh to £0.9/MWh per unit of total generation or £3/MWh to £9/MWh per unit of additional renewable generation.

Table 4 – Range of additional system costs in high demand scenarios (2002 prices)

Renewables penetration		Annualised / annual costs (£m)	Cost per unit of: all generation (£/MWh)	Cost per unit of: additional renewable generation (£/MWh)
20%	Lowest cost	143	0.3	3.3
	Highest cost	398	0.9	9.3
30%	Lowest cost	325	0.8	3.8
	Highest cost	921	2.2	10.8

2.9 For 30% penetration, the additional system costs range from £300m per annum to £900m per annum, equivalent to £0.8/MWh and £2/MWh respectively, per unit of total generation and £4/MWh to £11/MWh per unit of additional renewable generation.

2.10 The lowest costs were incurred consistently in the *Wind & Biomass*[3] scenario, and the highest costs in the *North Wind*[3] scenario. This finding applied irrespective of the level of penetration and is true not only of total system costs, but also of each of generation, transmission and distribution costs (discussed further below and in the following sections).

3 The technology/location scenarios are summarised in Table 3 and are discussed in detail in Section 3.

2.11 In Table 4, we illustrate these costs spread over two alternatives generation volumes – total generation and additional renewable generation. To set these values in context, it is worth noting that current wholesale prices are approximately £18/MWh and ILEX estimates wholesale prices in 2020 would have to be around £22/MWh[4], to support the required level of new thermal plant. Thus, the additional system costs per unit of total generation for 20% renewables are approximately 1% - 4% of the wholesale price, and for 30% are 4% - 10% of the projected wholesale price.

Scenario costs

2.12 In Table 5, we present the total additional system costs in each of the scenarios we have evaluated. It can be seen that unit costs in the High and Low demand cases are very similar, indicating that costs are not very sensitive to small changes in the level of demand.

2.13 In contrast, there is a step change in the level of cost in moving from 20% renewables to 30% renewables, where costs per unit of additional renewable generation increase by 16% on average.

2.14 The *Nuclear* scenario is based on the *North Wind* renewables scenario, and its costs are in line with the North Wind scenario with conventional non-nuclear capacity. This scenario is discussed further in paragraph 2.30.

Costs for 20% renewables penetration

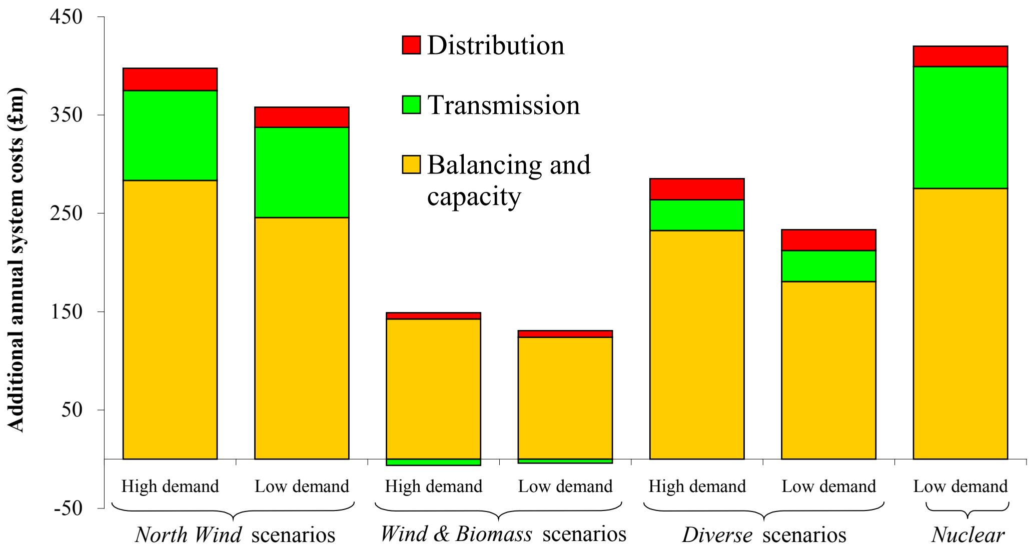
2.15 Figure 3 illustrates the additional annual costs for the 20% renewables scenarios, split by generation, transmission and distribution. In all scenarios, the costs of generation dominate transmission and distribution. It can also be seen that the *North Wind* scenarios (including *Nuclear*), have the highest costs in all three categories. Table 6 provides a breakdown of the additional annual costs for all scenarios.

4 This price is calculated for a conventional thermal system and does not include provision for the recovery of costs of build substantial renewable capacity, where the cost of such capacity is greater than the equivalent conventional generation. Nor does this price include the recover of the additional system costs identified in this report.

Table 5 –Additional annual system costs in each scenario

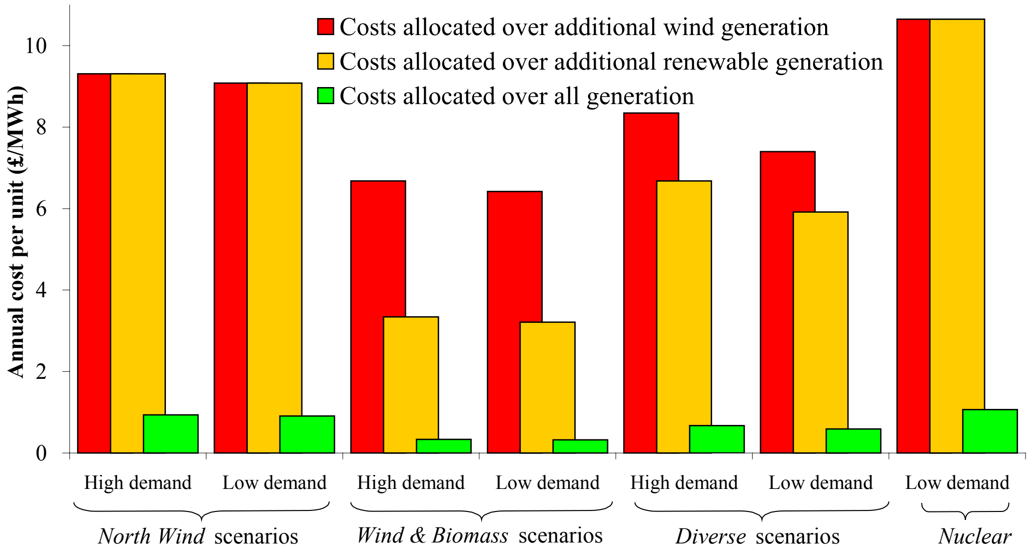
Scenario	Demand	Renewables	Annual cost (£m)	Unit costs (£/MWh) by generation: All	Additional Renewables	Wind
North Wind	High	20%	398	0.93	9.31	9.31
North Wind	High	30%	921	2.16	10.78	10.78
North Wind	Low	20%	358	0.91	9.08	9.08
North Wind	Low	30%	846	2.15	10.73	10.73
Wind & Biomass	High	20%	143	0.33	3.34	6.68
Wind & Biomass	High	30%	325	0.76	3.80	7.60
Wind & Biomass	Low	20%	127	0.32	3.21	6.42
Wind & Biomass	Low	30%	271	0.69	3.43	6.87
Diverse	High	20%	285	0.67	6.68	8.35
Diverse	High	30%	642	1.50	7.52	9.40
Diverse	Low	20%	233	0.59	5.92	7.40
Diverse	Low	30%	587	1.49	7.44	9.29
Nuclear	Low	20%	420	1.06	10.65	10.65

Figure 3 – Breakdown of additional annualised costs for 20% renewables



2.16 Figure 4 illustrates the unit costs in each of the 20% scenarios, calculated over the total volume of generation on the system, the volume of renewable generation and the volume of wind generation. In the *North Wind* and *Nuclear* scenarios, costs per unit of additional renewables and per unit of additional wind are the same, as all the additional renewable generation is from onshore and offshore wind.

Figure 4 – Additional system costs per unit of generation for 20% renewables



Costs for 30% renewables penetration

2.17 Figure 5 and Figure 6 present the total and unit costs for the 30% renewables scenarios. As with the 20% scenarios discussed above, generation costs dominate. Table 6 provides a breakdown of the additional annual costs for all scenarios.

Figure 5 – Breakdown of additional annualised costs for 30% renewables

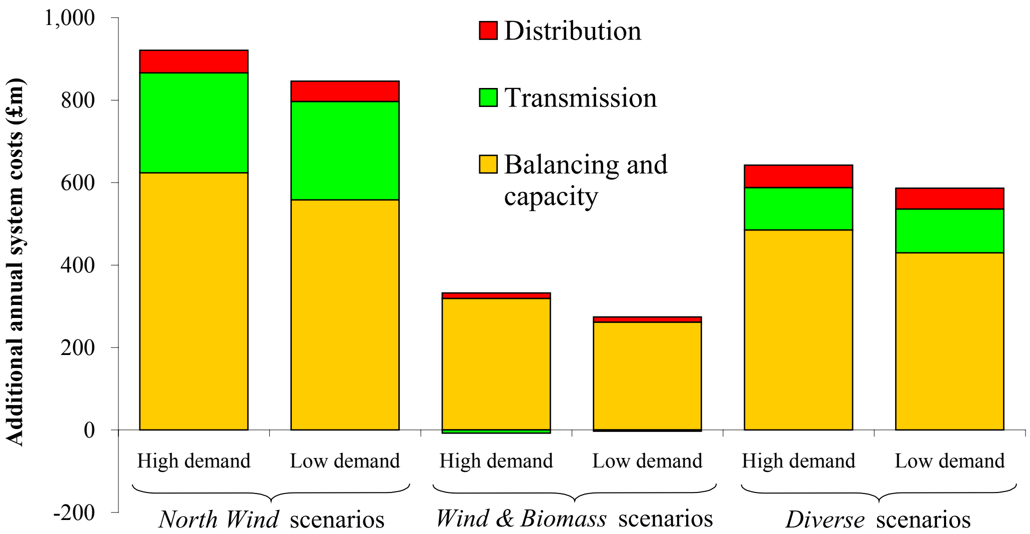
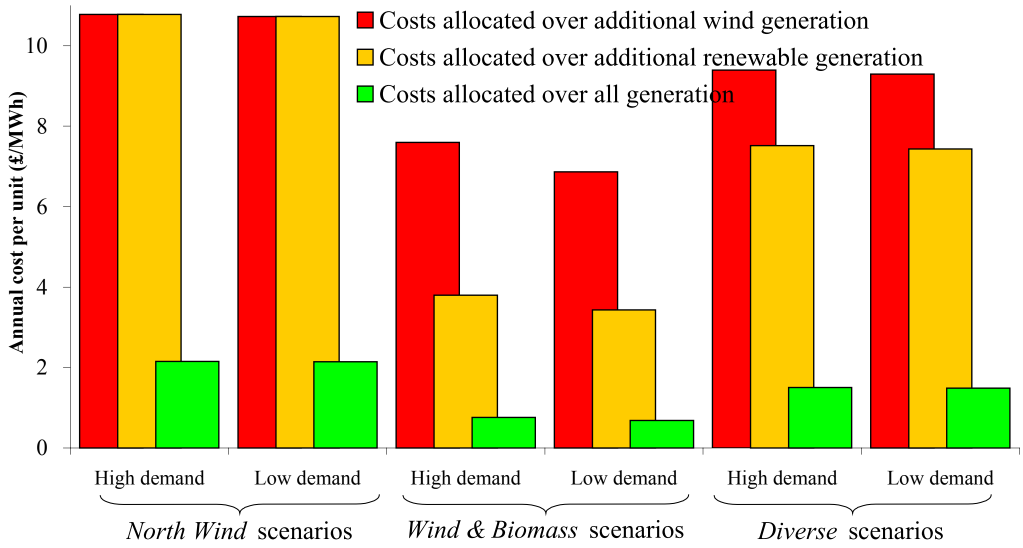


Figure 6 – Additional system costs per unit of generation for 30% renewables



2.18 A comparison of Figure 4 and Figure 6, which are presented on the same scale, illustrates the significantly higher unit costs in the 30% scenarios. On average, costs per unit of additional renewables are 16% greater in the 30% scenarios, which suggests that incremental system costs increase as the proportion of renewables rises.

Table 6 – Breakdown of additional annual system costs

Scenario	Demand	Renewables	Balancing	Capacity	Transmission	Distribution	Total
			Annual / annualised cost (£/m)				
North Wind	High	20%	93	191	91	23	398
North Wind	High	30%	217	407	242	55	921
North Wind	Low	20%	77	168	92	21	358
North Wind	Low	30%	196	362	239	49	846
Wind & Biomass	High	20%	47	95	-6	6	143
Wind & Biomass	High	30%	103	216	-8	13	325
Wind & Biomass	Low	20%	40	84	-4	7	127
Wind & Biomass	Low	30%	93	168	-3	12	271
Diverse	High	20%	75	158	31	22	285
Diverse	High	30%	170	315	103	54	642
Diverse	Low	20%	66	114	32	21	233
Diverse	Low	30%	150	280	106	50	587
Nuclear	Low	20%	82	194	124	21	420

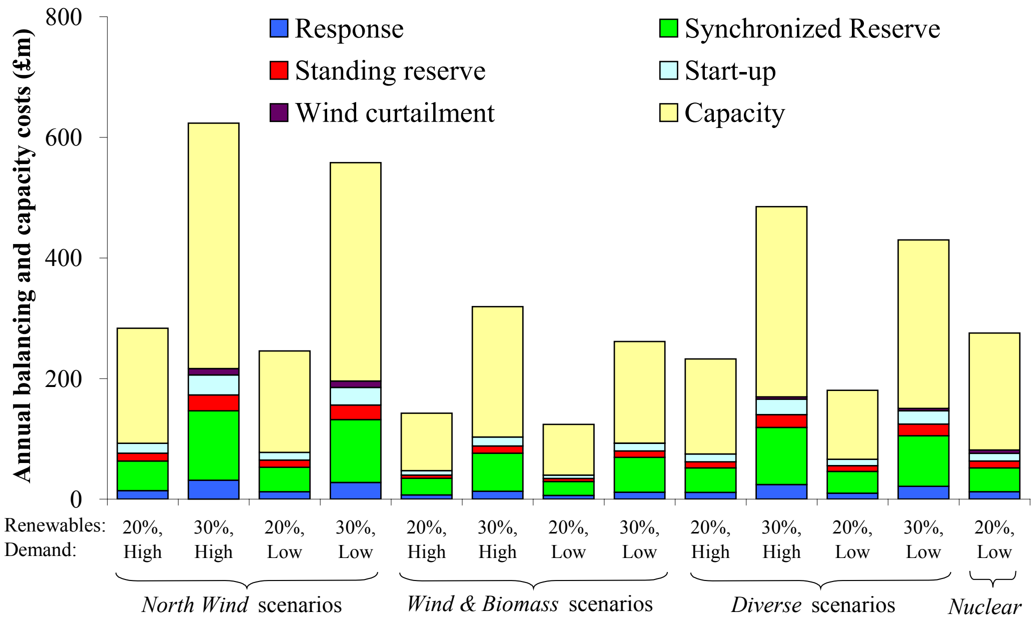
Analysis of generation costs

2.19 From Figure 3 and Figure 5, above, we have identified generation costs as the dominant element of system costs. In Figure 7 we break down generation costs into its constituent parts – capacity (for system security) and balancing. Balancing comprises costs of:

- response;
- synchronised reserve;
- standing reserve;
- start-up; and
- wind curtailment (defined below).

2.20 The role of each of these elements of generation costs and their calculation is discussed in Section 3.34. Within this study we have only separately identified the utilisation-related aspects of balancing costs. In addition to utilisation costs, providers of these services will also need to recover the costs of their investments in the generation assets (capacity costs). All capacity-related costs for the provision of balancing and system security services are included in the capacity element of costs, to avoid double-counting. For this reason, caution should be exercised in the separate use of figures quoted for balancing and capacity costs.

Figure 7 – Breakdown of additional generation costs



2.21 It can be seen from Figure 7 that capacity costs dominate not only generation costs but, given the relative magnitude of generation costs, transmission and distribution costs also. Capacity costs relate primarily to the provision of system security. In scenarios with a high volume of generation from wind, which provides a limited contribution to system security at these levels of penetration, additional costs are incurred in procuring relatively predictable conventional capacity to provide security.

Cost drivers

Intermittency

2.22 The intermittency of renewables is the single largest driver of system costs. The generation costs presented in Figure 7 are not location-specific, and so are driven only by the mix of technologies within the scenarios. These costs are substantially greater in the *North Wind* scenarios, where the additional renewables comprise 100% wind, and are also higher in the *Diverse* scenario that is 80% wind.

2.23 It can be seen from Figure 7 that capacity, synchronised reserve, response and wind curtailment costs vary most between these scenarios. These costs are related directly to the intermittency of wind.

- *Capacity costs* relate to the limited contribution that wind can make to system security, because of the correlation of output across generators and the risk of low wind speeds across the whole country for prolonged periods. In the values presented above, based upon statistical analysis we have carried out, wind makes some contribution to capacity at peak, but this contribution is significantly less than for equivalent conventional generation or non-intermittent renewables. Our calculations of capacity costs assume that the additional capacity required to maintain system security is provided by open-cycle gas turbine (OCGT) plant. New technological developments in storage, fuel cells or load management by 2020 may reduce the cost of providing this additional capacity. However, it is often argued that wind may be unable to contribute to system security at all, because of the risk of periods with hardly any wind at times close to maximum system demand. Although we found no evidence for this being a significant risk in the one year of generation data we studied, we have run a sensitivity which suggests that if wind were considered to have zero capacity value, this could increase the capacity costs reported in Table 6 by approximately 50%.
- *Synchronised reserve and response* are related to the balancing of generation and demand over seconds and minutes. Intermittency of wind increases the variance of generation pattern considerably, requiring greater reserve and response to be held on the system.
- *Energy curtailment costs* are incurred during periods of low demand, particularly on summer non-business days, where inflexible generation can exceed the demand. On windy summer days, wind generation may need to be constrained-off the system to avoid over-generation relative to demand.

Location of renewables

2.24 The location of renewable generation, like conventional generation, can have a significant effect on transmission, and to a lesser extent, distribution costs.

2.25 Transmission costs have historically been driven by a north-south flow from thermal generators located predominantly in the north, to demand in the south. With significant wind resources in Scotland and off the North West and North East of England and North Wales coasts, it is possible to envisage scenarios where this pattern of flows endures, despite the retirement of many of the existing conventional stations, thereby increasing the requirement for transmission reinforcement and the level of transmission losses.

2.26 Alternatively, if the additional renewables were developed across Great Britain and included the offshore wind resources around the England and Wales coast, as envisaged in the lowest cost scenario described above, then transmission reinforcement costs could be negligible and transmission losses might be reduced.

Connection of renewables to the transmission or distribution systems

2.27 In this study we have not considered the connection costs of developments. We have implicitly assumed a 'shallow' connection cost approach under which new lines between the generator and existing networks are counted as project costs (and thereby excluded) whereas consequential ("deep") system reinforcement costs have been included in our assessment. We have also assumed that large offshore wind developments connect to the transmission system. However, were these developments to connect at high voltage to the distribution system, it would have a substantial impact on distribution costs, doubling distribution costs on average. There would be no impact on transmission, as this already takes account of the energy flows from such plant and excludes connection costs. This finding is discussed further in Section 6.

Extent of renewable deployment

2.28 In paragraph 2.13 we observed a step change in costs per unit of renewable generation between the 20% and 30% deployment scenarios. This is observed across generation, transmission and distribution costs. Not only may additional renewables impose new costs directly on the system, but by offsetting more flexible conventional generation, it reduces the ability of the system operator to manage those costs.

2.29 In paragraph 2.12 we observed that there was no significant change in unit costs between scenarios with high demand and those with low demand. The demand in the high case is some 8% greater than the low case. The relatively small difference in renewables volumes between the two demand cases does not appear to have any significant bearing on cost. This finding is in contrast to the impact that the substantial increase in renewable generation brought about by a move from 20% to 30% would have on costs.

Impact of new nuclear generators

2.30 We have modelled the *North Wind* scenario for 20% deployment (with low demand) with two alternative mixes of non-renewable plant. In general, we have assumed that much of the existing coal and all nuclear (bar the Sizewell PWR[5] plant) retire prior to 2020. Even with the expansion in renewables to 20% or 30% of demand examined in this report, there would be a requirement for substantial new conventional capacity, up to 31GW. We have assumed this to be predominantly gas-fired.

2.31 However, we have also examined a mix of plant that retains the capacity of the AGR[6] nuclear reactors on the system, and includes the commissioning of two new nuclear plants (an additional 3GW). As nuclear plant is generally less responsive than other thermal plant, this scenario might be expected to increase generation costs. However, we found this effect to be only slight, with costs up 6%, predominantly due to higher wind curtailment costs. There is also a significant increase in capacity costs.

2.32 However, transmission costs increased significantly under this scenario, by £30m per annum (35%), largely due to increased north-south flows from the AGR plant.

2.33 In total, the additional costs of combining substantially increased renewables generation with a new nuclear programme were of the order of £62m per annum. This is 17% of the additional costs of renewables in the equivalent *North Wind* scenario.

Issues arising

Mix of renewable plant

2.34 The mix of renewable technologies deployed will be significant in determining the level of additional systems costs incurred. We have identified the intermittency of renewables, such as wind, as the principal driver of additional systems costs. That is not to say, however, that we should avoid intermittent generation in favour of more predictable technologies, such as biomass. Determining the optimal mix of renewable technologies will require an examination not only of the system costs described in this study, but also the costs of developing and operating the renewable capacity (the *project* costs).

2.35 Energy modelling to date has not tended to consider the impact renewables will have on system costs. But it is clear from the costs identified in this study, in extending renewables to 20% or 30% of demand, that an appropriate balance will have to be struck between *project* and *system* costs.

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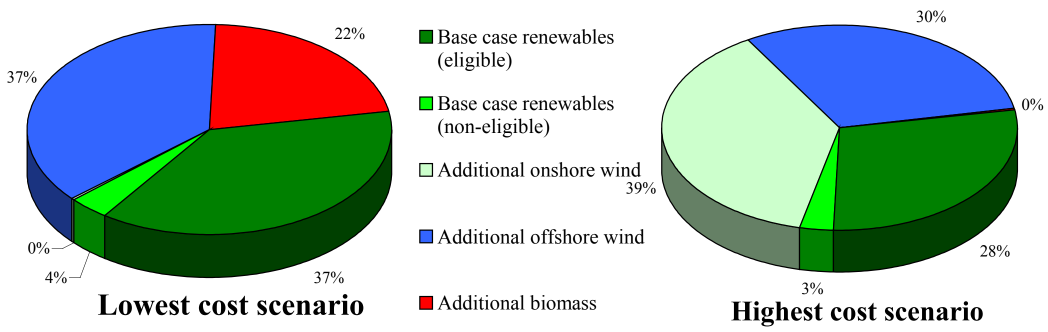
5 Pressurised Water Reactor

6 Advanced Gas-cooled Reactor

Figure 8 – Renewables capacity mix in lowest and highest system cost scenarios



Note: The additional capacity of renewables is substantially greater in scenarios with greater wind generation, as this technology has a lower load factor than biomass generators.

Allocation of costs

2.36 This report has not considered the appropriate allocation of the identified system costs. Given the significance of the system costs identified in this study, and the higher costs imposed by intermittent and northerly generation there may be an argument that allocating additional system costs to generators that impose them would provide an appropriate market signal to promote an efficient mix of plant on the system.

Locational signals

2.37 At present TNUoS charges vary by location, penalising generation in the north and rewarding generation in the south. These signals may be reinforced shortly by the imposition of locational transmission losses, which is the subject of two proposed modifications to the Balancing Settlement Code (BSC).

2.38 We have identified a need for substantial new conventional capacity in addition to the growth in renewables to replace retiring plant. We have assumed that the plant locates efficiently, given the appropriate locational signals on the electricity and gas networks. If such signals are weakened or inefficient, plant locations could become sub-optimal, increasing transmission costs beyond those considered here.

2.39 Our findings on transmission suggest that renewable, like conventional generation, can impose substantial costs on the transmission system if located away from sources of demand. The results of this work would not support any weakening of locational signals for renewable generators.

Stranded assets

2.40 We have found no evidence of significant assets in generation, transmission or distribution becoming stranded due to further increases in the share of renewables over the period 2010 – 2020. This is not altogether unexpected, given the length of time the systems have to adjust between now and 2020.

3. CORE APPROACH AND METHODOLOGY

3.1 In this section we set out the approach, methodology and assumptions that are common to all three elements of system costs. Those assumptions that are specific to the quantification of generation, transmission or distribution costs are discussed in subsequent sections.

The 2020 base cases

3.2 The base cases define the make-up of the electricity system in 2020 with renewables making up 10% of the total generation. Our scenarios all describe a unified Great Britain system, as envisaged within the proposed British Electricity Trading and Transmission Arrangements (BETTA).

3.3 Three base cases have been developed:

- high demand;
- low demand; and
- low demand with increased nuclear generation.

Demand

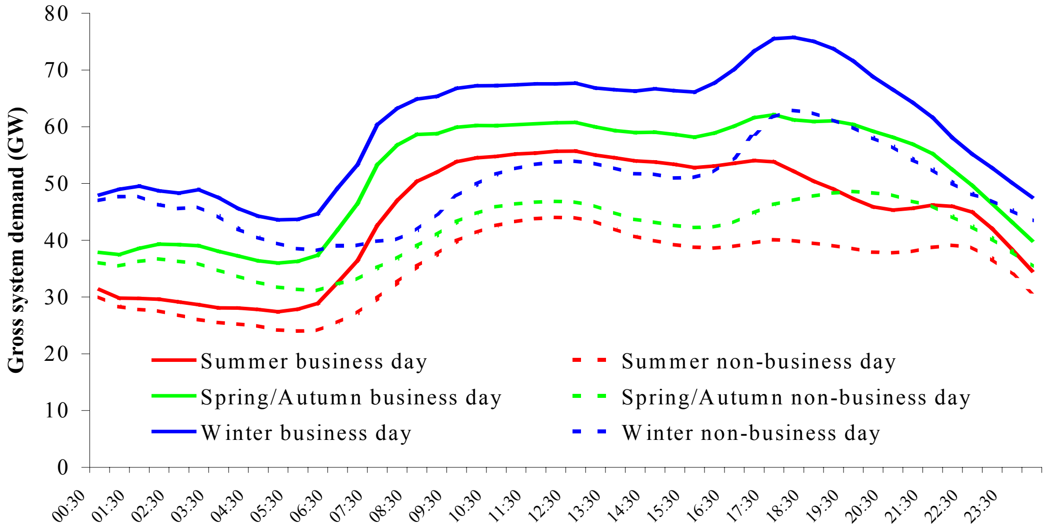
3.4 In describing the base cases, we first determined the level of demand, both gross demand and the net demand on the transmission system[7]. We developed two views of growth in both the annual and peak demand – a business as usual, high demand case, where peak demand and the annual volume of demand continue to grow at a rate of 0.8%, and a low demand case, where demand is held constant beyond 2010.

3.5 By 2020, annual gross demand in the high case is 427TWh and peak demand is 76GW. In the low case these values are 8% less at 394TWh and 70GW, respectively.

3.6 We developed profiles for the *shape* of demand over the day. We simplified the year to six sample days - a business day and non-business day in each of a summer, winter and a shoulder spring/autumn season.

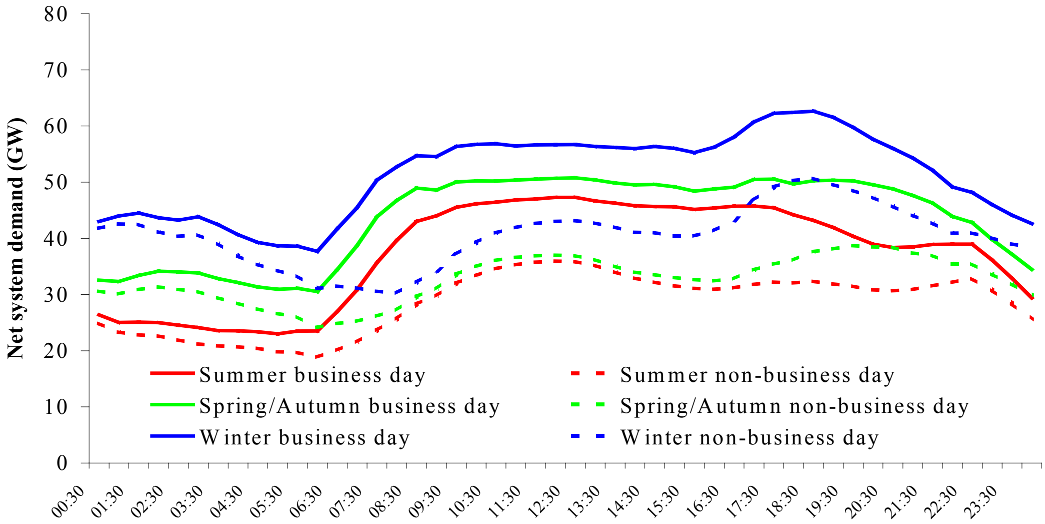
[7] Our estimate for gross demand reflects the total electricity consumption in Great Britain, irrespective of the source of power used to satisfy demand. In contrast, our projections for net demand reflected transmission system demand, after demand met from distributed generation such as CHP, micro-CHP and other on-site generation, had been satisfied. For the purposes of the balancing costs assessment, we assumed that all renewable generation other than wind was below the level managed by the system operator.

Figure 9 – Gross 2020 system demand by sample day for the high demand case



3.7 Next, we calculated transmission system demand by netting off distributed generation including non-wind renewables, CHP and micro-CHP. Our assumptions for these technologies are discussed later in this section. Finally, we netted off from this demand energy generation from large-scale hydro plant and adjusted demand to reflect the historical scheduled utilisation of generation and pumping of pumped storage units not providing balancing services. This left a residual system demand to be met from conventional generation and wind.

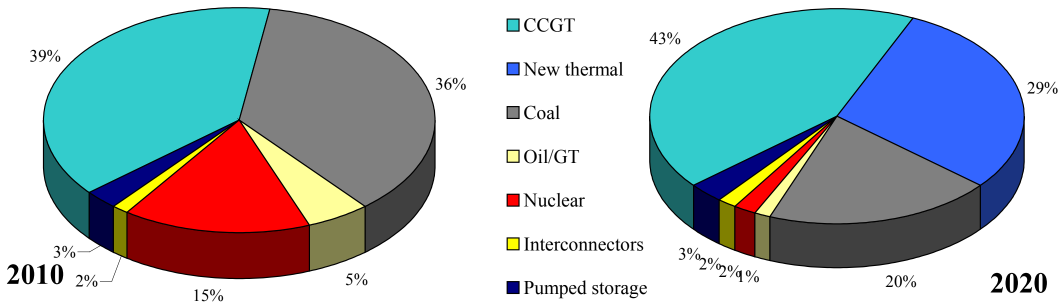
Figure 10 – Net 2020 system demand by sample day for the high demand case



Conventional plant mix

3.8 From the net demand values, we calculated the required conventional capacity to be able to meet peak demand under the CEGB generation security standard. In deriving this value, we took two views as to the level of contribution that interruptible renewables, such as wind, are able to make to system security. These assumptions are discussed further in Section 3.34.

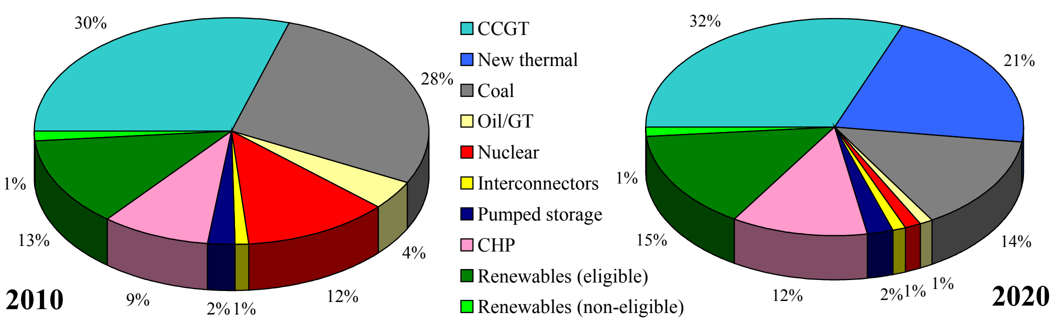
Figure 11 – Net conventional capacity mix in 2010 and 2020 in low demand base case



3.9 Figure 11 illustrates the mix of conventional capacity assumed for 2020 in the low demand base case. As a point of reference, we have also illustrated the assumed capacity mix in 2010. We assume that the Magnox nuclear generators retire prior to 2010, and the AGRs, prior to 2020. By 2020, we also retire 15GW of coal generation, as the existing fleet will be fifty to sixty years old in 2020, much of it probably beyond economic life-extension. In all scenarios, there is a requirement for substantial new conventional generation (in addition to the assumed 20% or 30% renewable generation). We have assumed this capacity is gas-fired.

3.10 In the high demand case, a further 7GW of additional gas generation is included. In the nuclear scenario we retain the AGR fleet through to 2020 and commission 3GW of new nuclear capacity (as discussed in paragraph 2.31). This reduces, but does not eliminate, the need for new gas-fired generation.

Figure 12 – Net capacity mix in 2010 and 2020 in the low demand base case



3.11 Figure 12 illustrates the total mix of capacity in the low demand base case, and includes CHP and eligible renewables consistent with the Government's targets for 2010 of 10GW of CHP capacity and 10% renewables.

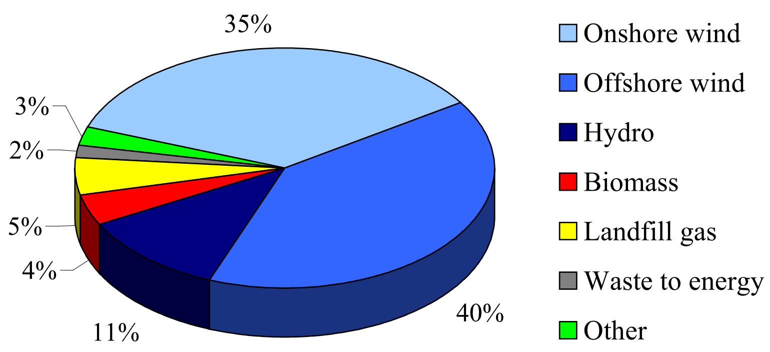
Location of conventional plant

3.12 In determining the location of new conventional generation, we firstly assumed that proposed project sites are utilised. Thereafter, we assumed an efficient location for the electricity and gas transmission systems, utilising the brown field sites of retired plant. This is consistent with developers being swayed by the locational price signals charged by NGC and Transco. This has led to new plant generally being located in central, eastern and southern England. We have also assumed that there is 2GW of new plant in central Scotland, to provide system support after the assumed retirement of Longannet, Cockenzie and (except in the *Nuclear* scenarios) the Torness and Hunterston AGRs.

Renewable plant mix

3.13 It was a given within the terms of reference of this study (attached as Annex G) that the baselines would assume that the Government's target for 10% renewables by 2010 would be met. We have determined the mix of renewables in our baselines from ILEX's database of over 1,000 commissioned, developing and proposed renewable projects. However, the capacity of these projects falls some way short of the target. To meet the target we have included additional onshore and offshore wind generation, in the proportion 33% onshore and 67% offshore. We have chosen these technologies because they are closest to market, with the lowest costs. The resultant mix is shown in Figure 13. For the high demand baseline, additional renewables (again assumed to be onshore and offshore wind) are required beyond those to meet the target in 2010, so as to maintain renewables at 10% of demand.

Figure 13 – Renewable capacity mix for low demand baseline (10% renewables)



CHP and micro-CHP

3.14 Like renewables, CHP deployment to meet the Government's 10GW target was a given for the baselines. This represents a 50% increase over the current capacity of CHP. We have assumed a mixture of packaged and bespoke CHP, with 20% of capacity sized less than 5MW, 60% sized 5MW-20MW and the remaining 20% above 20MW. We assumed that the present locational mix was maintained for new CHP plant. We assumed a range of operating profiles, with 50% of capacity operating baseload, and the rest at lower load factors.

3.15 The study has also assumed a substantial take-up of domestic and other micro-CHP after 2010, with 2GW of plant installed by 2020. The plant is expected to follow the domestic heat load and operate for sustained periods over winter and spring/autumn.

The renewables scenarios

3.16 We developed twelve scenarios for renewables deployment, in addition to the three baselines discussed above, that combine scenarios for high and low demand, 20% and 30% deployment and three alternatives for technology and location.

Penetration

3.17 We have considered two levels of renewable penetration, 20% and 30% of gross demand. It follows that in high demand scenarios, the volume of renewables required is greater, by some 8%. In all cases, we have determined the extent of renewable deployment, mix of technologies and locations based on the volume of required renewable generation. References to the capacity of renewables reflect a view of the load factors at which each technology will operate and can vary from, for example, approximately 30% for wind, to baseload for biomass. Our load factor assumptions are discussed later in this section.

Technology

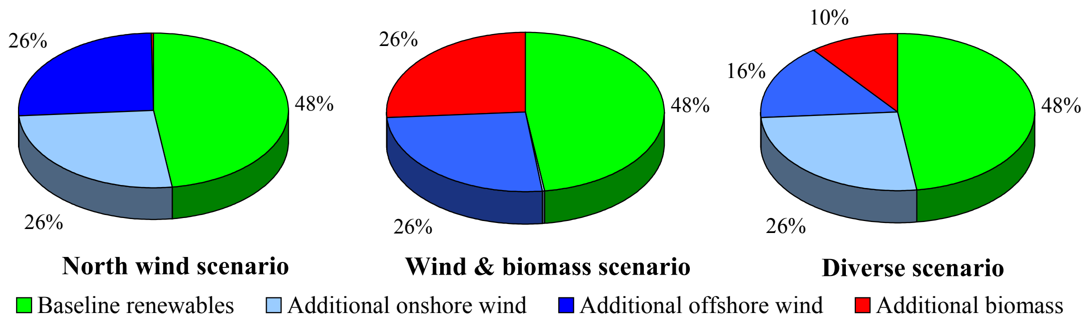
3.18 Three scenarios of renewable technology and location have been considered. These are summarised in Table 7, below.

Table 7 – Summary description of renewable technology and location scenarios

Scenario name	Type and location of additional renewable generation
North Wind	Equal volumes of onshore and offshore wind. Onshore wind located predominantly in Scotland and offshore wind predominantly in northern and eastern England.
Wind & Biomass	Equal volumes of offshore wind generation and biomass generation. Offshore wind located around the coast of England and Wales and biomass throughout Great Britain.
Diverse	Half of new renewable generation from offshore wind, 30% of generation from onshore wind and the remaining 20% from biomass. All technologies located throughout Great Britain.

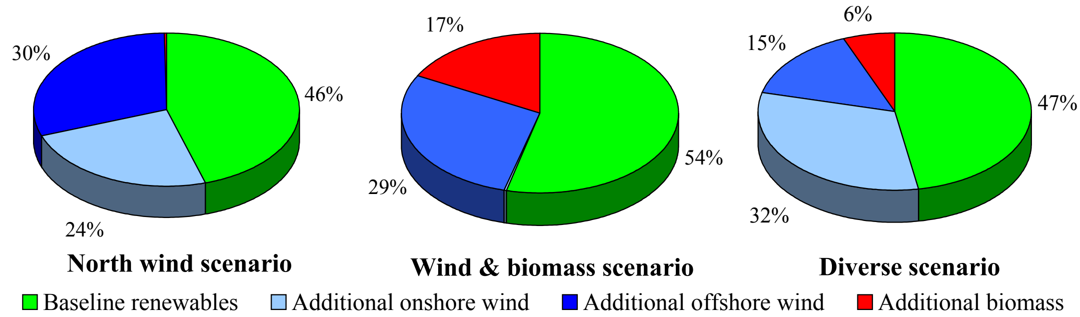
3.19 We have considered only two key technology types to provide the required capacity to meet the 20% and 30% thresholds, wind and biomass. This simplistic assumption does not represent a belief that only these two technologies will be developed, but that these technologies reflect two extremes – intermittency and unpredictability on the part of wind - and baseload predictability on the part of biomass. By using these two technologies as examples, we believe we have spanned the range of likely system costs.

Figure 14 – Generation by technology in 20% renewables scenarios with high demand



3.20 In Figure 14 we present the mix of renewable technologies, by generation volume, in each of the scenarios. In Figure 15 we illustrate the mix by capacity. The split of baseline renewables is given in Figure 13.

Figure 15 – Capacity by technology in 20% renewables scenarios with high demand



Note: The additional capacity of renewables is substantially greater in scenarios with greater wind generation, as this technology has a lower load factor than biomass generators.

Onshore wind

3.21 Wind generation is a maturing technology, but one where production costs continue to decline, turbine capacities are increasing rapidly, and control technologies are improving. In converting our scenarios for generation from wind into equivalent capacities, we have assumed that the load factor of wind will improve over time to a little over 30%. This is substantially better than that observed from the present wind generation data we have analysed, where annual load factors are between 25% and 28%.

Offshore wind

3.22 Offshore wind development is a relatively new progression for wind generation, though the core technology is the same as onshore wind. We have assumed that free of local microclimates and with more consistent wind speeds, offshore load factors are 36% for proposed projects, rising to 39% for further developments, as control technologies improve and turbine sizes continue to increase.

Wind profiles

3.23 We observed significant discrepancies between anticipated wind generation derived from wind-speed data and actual wind generation. Most previous work in this area has been based on wind speed data, converted into anticipated generation by using manufacturers power curves. However, our analysis of actual generation from GB wind farms suggests that using wind speed data overestimates generation and underestimates intermittency. As a result, this study utilises only actual half-hourly metered generation data from UK wind farms in its assessment of generation costs.

3.24 Consistent data was gathered from all available sources to examine the extent of diversification in wind generation. In total, we gathered usable data from 39 projects around the UK[8] over a consistent eleven-month period. This period is somewhat shorter than desired, but we were keen to exclude abnormally low output values observed in the generation data for the period April to July 2001.

3.25 We observed from the wind data set that there was as much variation in output within region as there was across regions. It was not possible, with the limited data set available, to develop regional patterns of generation. Clearly such a small data set, representing 200MW of wind capacity, would not be representative of the diversity of wind generation that systems with 24GW or more wind would exhibit. To build a profile for substantial wind generation, we could not simply scale the observed output. We therefore created diversity by time-slipping[9] proportions of the aggregate half-hourly wind profile, to build up a new profile representative of substantially larger wind systems. The degree of diversity introduced was an arbitrary assumption, with our target level of diversity being a midpoint between the observed diversity exhibited by the 39 wind projects for which we had data and a theoretical maximum diversity if output across a much larger number of projects was uncorrelated.

Biomass

3.26 Our use of biomass is representative of a number of baseload, predictable, renewable generation technologies. Biomass can comprise a wide range of technologies and fuel sources. In this context we have considered energy crop incineration as the most likely form of biomass generation to be capable of providing substantial capacity. In practice, we would anticipate a mix of technologies and fuel sources, but these might be expected to exhibit similar characteristics in aggregate.

3.27 We have assumed the baseload operation of a large number of small plant, perhaps 30MW-50MW at the extreme, with size limited by the ability to transport and store large volumes of low energy-density feedstock. We have assumed an availability of 66% to take account of planned and forced outage and feedstock supply issues.

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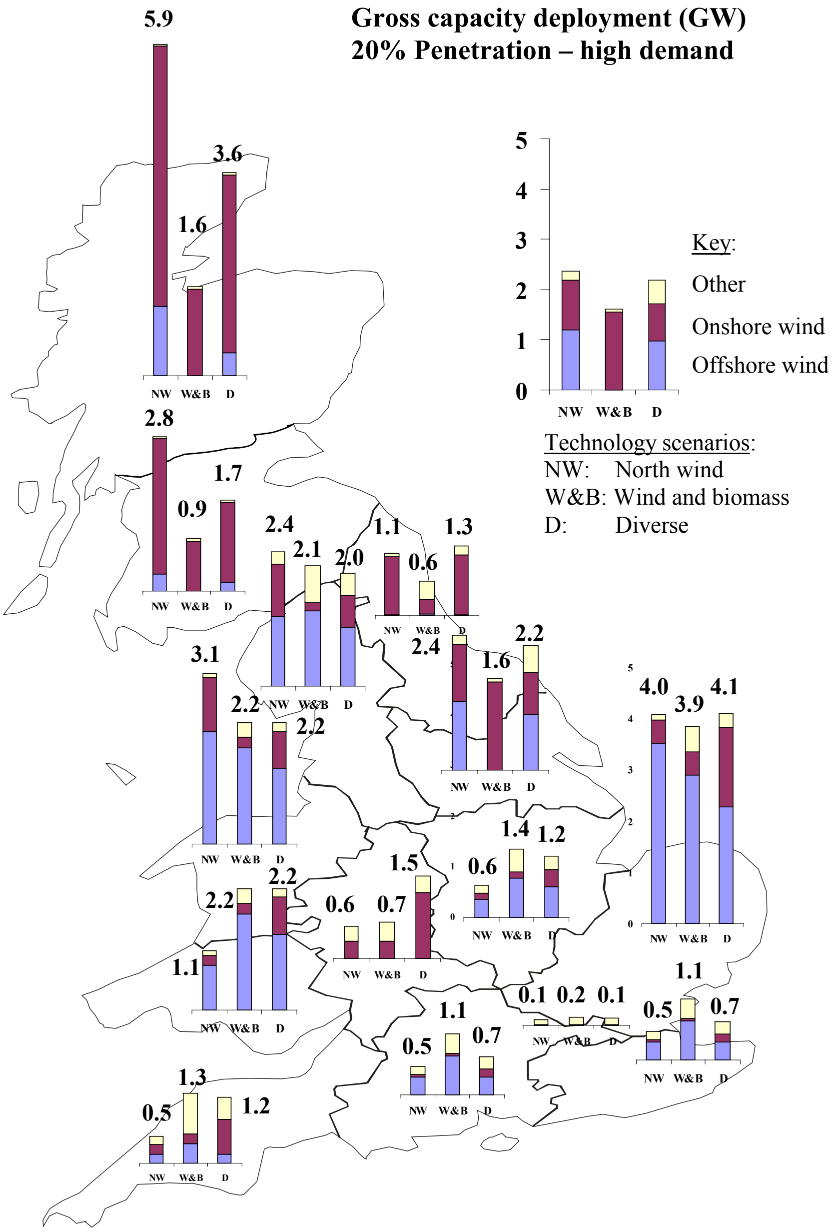
8 The data spanned sites throughout Great Britain, though a number of the sites were clustered in the North West and North East of England. We found as much correlation and variance in sites across the country as we did in those located in the same regions. On this basis we believe that data is representative of Great Britain as a whole.

9 Time-slipping involved scaling-up the observed generation data by overlaying annual half-hourly aggregate generation profiles for the 39 projects, but slipping each tranche of data by half-an-hour more than the last tranche. For example, to create the output equivalent to 117 projects we would have laid the first profile representing the aggregate output of 39 projects commencing 00:00 on 1st January, the second commencing at 00:30 and the third at 01:00, thereby artificially increasing the observed diversity in the generation data.

Figure 16 – Regional renewables capacity mix (GW) by 20% scenario



Location

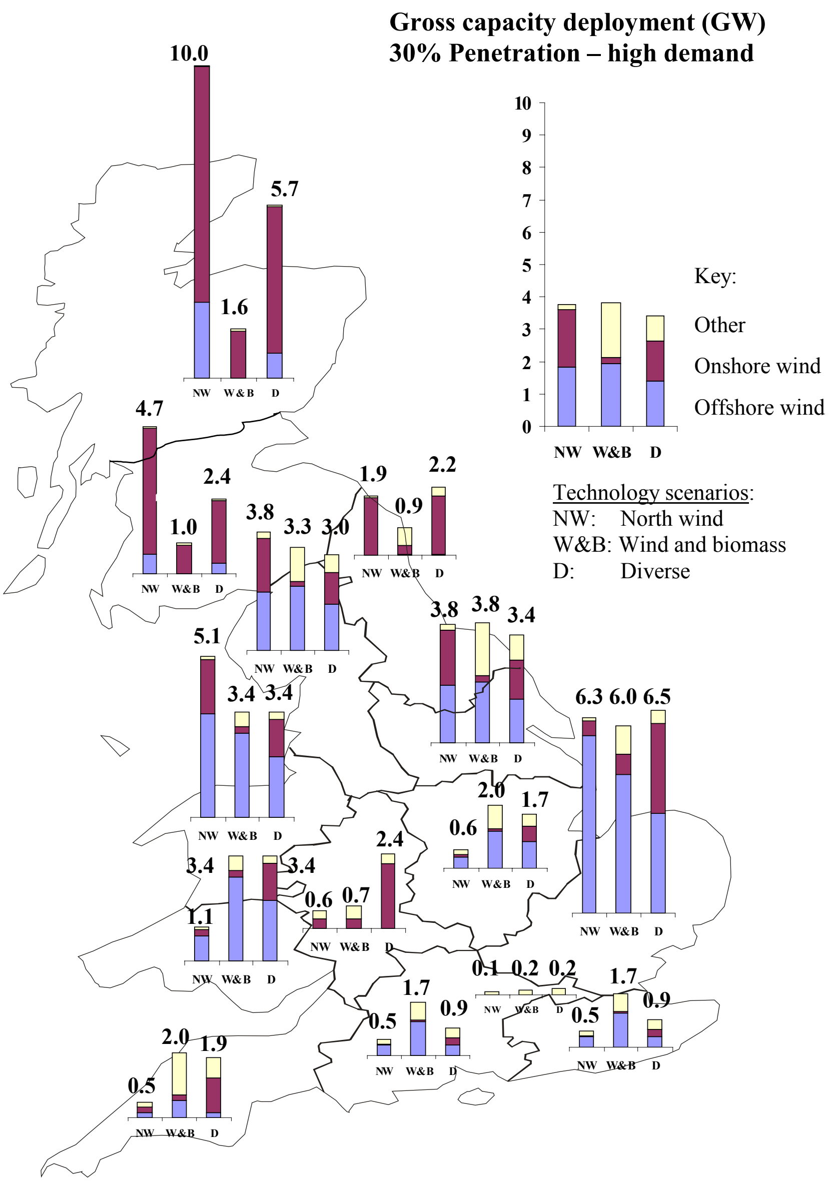
3.28 In determining the location of new renewables, we have been guided by a number of considerations and sources. The first is the regional renewable energy assessments[10]. These assessments identified resource availability for a number of renewable technologies, including onshore and offshore wind and biomass. The

[10] Regional Renewable Energy Assessments: A report to the DTI and the DTLR. OXERA Environmental / ARUP Economics and Planning. February 2002.

assessments relate predominantly to the period to 2010, so we have generally taken these as a guide only, and allocated required volumes of generation needed to comprise our renewable scenarios to regions in proportion to the identified resource for that technology. In the North Wind Scenario, we have only allocated renewables to northerly regions (and East Anglia).

3.29 The significant exception we made to the use of the regional assessment was in relation to Scotland. Advice from the Scottish transmission companies suggested that the number and size of connection enquiries they had received would support a greater allocation of onshore wind to Scotland.

Figure 17 – Regional renewables capacity mix (GW) by 30% scenario



Annualisation of results

3.30 In this report we have presented assessments of costs on a consistent basis reflecting:

- total capital expenditure (transmission and distribution only);
- annual or annualised costs; and
- costs per unit of:
  - all generation;
  - all renewable generation; and
  - all wind generation.

3.31 Our annualised transmission and distribution costs are based on the required annuity to recover the capital investment over a 40-year asset life at a regulated real pre-tax discount rate of 6.25%.

Capacity cost for OCGT

3.32 In calculating the costs of generation capacity, we have assumed a fifteen-year project life for Open Cycle Gas Turbines and a 13% real pre-tax rate of return, giving an annualised cost of £47/kW. This cost comprises the investment cost of the project and annual fixed operation and maintenance costs. We believe this value is consistent with the long-term costs of merchant capacity provision by independent power developers, where the investment is not backed by long-term contracts for the utilisation or support of the plant.

3.33 Alternatively, if generation capacity for system security were supported by long-term contracts or an explicit capacity-support mechanism, the required rate of return might be reduced to 8%-10% (real, pre-tax), lowering the cost of an OCGT from £47/kW/pa to between £38/kW/pa and£42/kW/pa. This could reduce the capacity costs in this report by approximately 10%-20%.

Table 8 – Annualised cost of OCGT capacity (£/kW/pa)

Discount rate / Life	15 years	30 years
8.0%	38	32
13.0%	47	42

*Real pre-tax rate of return

3.34 Furthermore, if the developer were prepared to recover the costs of its investment costs over a longer period, capacity costs could be reduced further. Whereas an independent generator might require to recover its costs over a 15-year period, other potential providers could take a longer view, over the life of the asset, of perhaps 30 years.

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4. BALANCING AND CAPACITY COSTS

4.1 This section is principally concerned with the ability of an electricity system with a high penetration of renewable and other intermittent generation to maintain a desired level of *security* of supply, both in the short and the long term. System security involves operational and design practices including maintaining appropriate levels of reserve and flexibility necessary to keep the system operating under a range of conditions – including credible plant outages and predictable and uncertain variations in demand and availability of primary generation resources, including wind.

4.2 One important aspect of system security is the ability to balance demand and generation over various time scales. The penetration of new renewable generation sources may impose additional requirements on the remaining large conventional plant and drive the need for new technologies and solutions to deliver both the capacity and flexibility necessary to maintain the continuous balance between load and generation. This may, of course, have additional cost implications, and the quantification of such costs is the main focus of this section.

4.3 Below, we discuss our methodology, assumptions and results on the various system requirements for *capacity* and *flexibility*. The impact of renewable generation on these two requirements is analysed through:

- quantifying the capacity and cost of conventional plant required to maintain adequate security of supply in a system supplied by a considerable contribution of intermittent sources; and
- quantifying the additional requirements and costs of balancing the system in the operational time-scale (from several minutes to several hours), primarily driven by fluctuations in wind generation output.

Security of supply-driven capacity costs

4.4 Generation capacity above system maximum demand is required to meet predictable and uncertain variations in demand under circumstances of plant outages and interruptions to primary fuel sources. On a thermal generation system, demand uncertainty is the main cost driver, but on a system with a large volume of intermittent generation, such as wind, greater generation uncertainty is introduced. The objective of the analysis was to determine the contribution of intermittent renewable resources to system security or, in other words, to determine the amount of capacity of conventional plant that can be displaced by intermittent renewables whilst maintaining the same degree of security. We have performed simulation studies to quantify the generation margin required to deal with the uncertain availability of renewable sources and with the utilisation of this capacity.

4.5 The current market does not operate to a statutory or formal generation security standard that would require a given capacity margin for any particular mix of plant to be available to maintain adequate security of supply. We have taken the last security standard employed in the UK, by the CEGB ahead of privatisation in 1990, as indicative of the degree of confidence required. In particular, the Report on the Generation Security Standard, by the Electricity Council (1985), was used as a reference.

4.6 The security standard is applied to the statistical probability that consumers of electricity may be faced with the loss of their supplies. The risk of peak demand exceeding available supply is taken to be 9% (interruptions in supply should not occur in more that nine winters in one hundred). Based on the probabilities of plant failure considered reasonable in the 1980s, the standard would require a capacity margin of approximately 25% on a conventional thermal generation system. By comparison, in 2001, the England and Wales system had a capacity margin of 28% over the maximum demand of 53GW[11].

4.7 The assessment was based on the assumption that the outage rate of conventional plant is 15% (85% availability)[12]. The analysis is further simplified by assuming that all conventional generating units have a generic capacity of 500MW. A standard two-state operation model was applied to simulate the behaviour of the generating unit:

- unit fully available, with the probability of 0.85, and
- unit completely unavailable, with the probability of 0.15.

4.8 It was further assumed that there is no correlation between the availabilities of individual conventional units – failure of one does not increase the risk of failure of others.

4.9 On the other hand, the intermittent behaviour of wind was statistically assessed from the frequency distribution of GB wind generation, obtained from the annual half-hourly profiles of wind output, developed for each of the scenarios from historic wind generation data, as discussed in paragraph 3.23.

4.10 Assuming no correlation between the failures of individual generating units, the behaviour of conventional units and wind generation was then statistically combined, enabling the risk of peak demand exceeding available generation to be assessed. This analysis was then employed to calculate the minimum number of generic conventional units necessary to ensure that the risk of loss of supply is not greater than the 9% security standard in the combined conventional and wind generation system.

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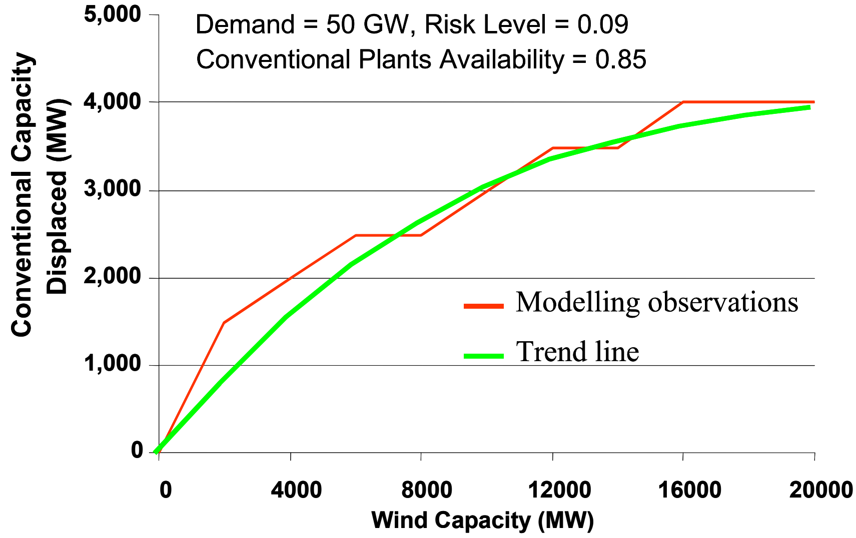
11 C. Davies, Grid Issues, Presentation to the BWEA, NGC, April 2002.

12 This availability rate is low by modern observed levels of availability, but the Steering Group was keen to avoid an arbitrary change to the standard.

Figure 18 – Capacity of conventional plant that can be displaced by wind generation



4.11 Based on the developed methodology, a study was then performed to assess the ability of wind generation to displace capacity from conventional plant. The contribution of wind generation to capacity is presented in Figure 18, for various levels of installed wind capacity, assuming a system with a peak demand of 50GW. It can be observed that for a small level of penetration the capacity value of wind is significant – since 4GW of wind generation displaces about 1,500MW of conventional plant (modelling observations line in Figure 18). However, as the capacity of wind generation increases, the marginal contribution declines: 20GW of wind capacity displaces only about 4GW of conventional generation.

4.12 The analysis confirms the expected results (the trend line in Figure 18), that at low levels of penetrations, the capacity value of any source is not dependent on its availability. The key factor is the average power that the source delivers at times when the system is at risk (winter peak, in this case)[13]. However, as the capacity of intermittent source rises, it becomes increasingly less valuable for displacing the capacity of conventional plant, since there are times with little or no wind (adding significant amounts of wind capacity does not considerably increase the diversity of wind output and there will still be times with no little, or no, wind).

4.13 For a system with discrete sizes of conventional plant (500MW), there would be some deviation from the idealised case. However, this discrepancy reduces with the level of penetration.

[13] Although there is a degree of correlation between wind energy production and season, wind generation in winter in Britain is very weakly correlated with peak demand. We have assumed no correlation.

4.14 As this study was based on a one-year time series of wind generation data (for which a consistent set of data was available), extreme conditions of the coincidence of very high demand and little or no wind may not be captured. In the extreme, where large, high-pressure weather systems may prevent wind generation over the whole of Great Britain for potentially days, wind generation would not contribute at all to system security. A number of authors[14] have suggested that such conditions are regular occurrences and are positively correlated with levels of maximum system demand in winter. Conventional generation, together with other non-wind renewables would have to meet maximum demand and the required margin. The maintenance of this greater volume of peaking capacity, to provide security in such instances, imposes an additional cost on the system.

Table 9 – Requirements for conventional plant capacity, with and without a capacity contribution from wind generation

Scenario	Demand	Penet-ration	Peak demand	Wind capacity	Conventional capacity	
					with wind	no wind
			MW	MW	MW	MW
Baseline	High	10%	62,182	9,914	74,000	77,500
Baseline	Low	10%	56,436	8,877	67,500	70,500
Nuclear baseline	Low	10%	58,210	8,877	69,500	73,000
North Wind	High	20%	62,182	23,978	72,000	77,500
North Wind	High	30%	62,182	38,042	70,500	77,500
North Wind	Low	20%	56,436	21,864	65,500	70,500
North Wind	Low	30%	56,436	34,852	64,000	70,500
Wind & Biomass	High	20%	59,737	16,165	70,000	74,500
Wind & Biomass	High	30%	57,292	22,415	66,500	71,500
Wind & Biomass	Low	20%	54,178	14,649	64,000	68,000
Wind & Biomass	Low	30%	51,920	20,421	60,000	65,000
Diverse	High	20%	61,204	21,478	71,500	76,500
Diverse	High	30%	60,226	33,042	69,000	75,500
Diverse	Low	20%	55,533	19,556	65,000	70,000
Diverse	Low	30%	54,629	30,234	62,500	68,500
Nuclear	Low	20%	56,436	21,864	65,500	70,500

4.15 In order to account for this effect, the analysis of required capacity of conventional plant is also performed, assuming no contribution of wind to system

[14] Most recently, M. Laughton, Renewables and UK Grid Infrastructure, Power in Europe, Issue 383, 9 September 2002. Platts

capacity. For each of the analysed scenarios the need for conventional plant is summarised in Table 9.

The cost of additional conventional capacity

4.16 As wind generation does not provide, or provides only limited contribution to capacity margin, conventional generation that is not required to provide energy to the system (as this is being provided from wind), is required to maintain system security. There are a number of ways in which the cost of the additional capacity can be calculated. The most comprehensive manner would be to calculate the total capacity and energy costs of the electrical system as a whole. However, this route would not enable us to segregate the capacity costs from the costs of establishing renewables, and so would not meet the remit of the study. Additionally, costs calculated by this route are extremely sensitive to the assumed cost of new renewables. As there is considerable uncertainty over these costs, applying this approach would provide a very broad range of results.

4.17 We have therefore adopted a somewhat more simplistic approach, but one we believe produces robust results. Firstly, we have calculated the annual wind generation in each scenario and determined the equivalent amount of conventional capacity required to produce the same generation, assuming a CCGT operating at 85% load factor. For example, 10GW of CCGT would produce the same output as the 24GW of wind that is assumed in the 20% *North Wind* scenario with high demand. However, conventional capacity can be viewed as delivering two services, energy production and capacity. If we firstly consider that wind can provide no contribution to capacity margin (as discussed in paragraph 4.11 above), then to be equivalent to the conventional generation, wind would require back-up from generation equal to the equivalent conventional capacity. This capacity could come from a number of sources, including old conventional generation or new open cycle gas turbines (OCGTs). We have costed the capacity requirement at the price of a new, but not leading edge, OCGT (£47/kW/pa[15]), suitable for peaking operation. We consider that, at the margin, only OCGTs will be used, as any economically feasible existing generation would already be utilised on the system[16].

4.18 If we believe that wind does contribute to system security, as discussed above in paragraph 4.11, albeit at a lower rate than conventional capacity, then the above capacity requirement is reduced by the level of that contribution. In the example above, the 24GW of wind on the system may contribute up to 5.5GW (see Table 9) of capacity, reducing the requirement for additional capacity to 4.5GW. In scenarios with lower wind penetration, including the baselines, the contribution to security per GW of wind will be greater.

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15 The derivation of this value is discussed in paragraph 3.32.

16 Existing coal generation is likely to be fifty to sixty years old by 2020 and may not be able to reliably provide system security.

4.19 In this methodology, we have assumed that wind generation is equivalent to that from a CCGT. However, this is an over-simplification. The wind generation, even with the additional OCGT capacity, will not be directly equivalent to that from a CCGT, because wind is less controllable and so will not operate at the same periods of the year. Our analysis suggests that wind generators will on average earn a price in the energy market equivalent to time-weighted average price, whereas a CCGT operating at an 85% load factor might earn a generation-weighted average price some 4% above this level in 2020. Correcting for this discrepancy adds a further cost of £0.5/MWh to the generation.

4.20 A worked example of this calculation is provided in Annex D.

Capacity results

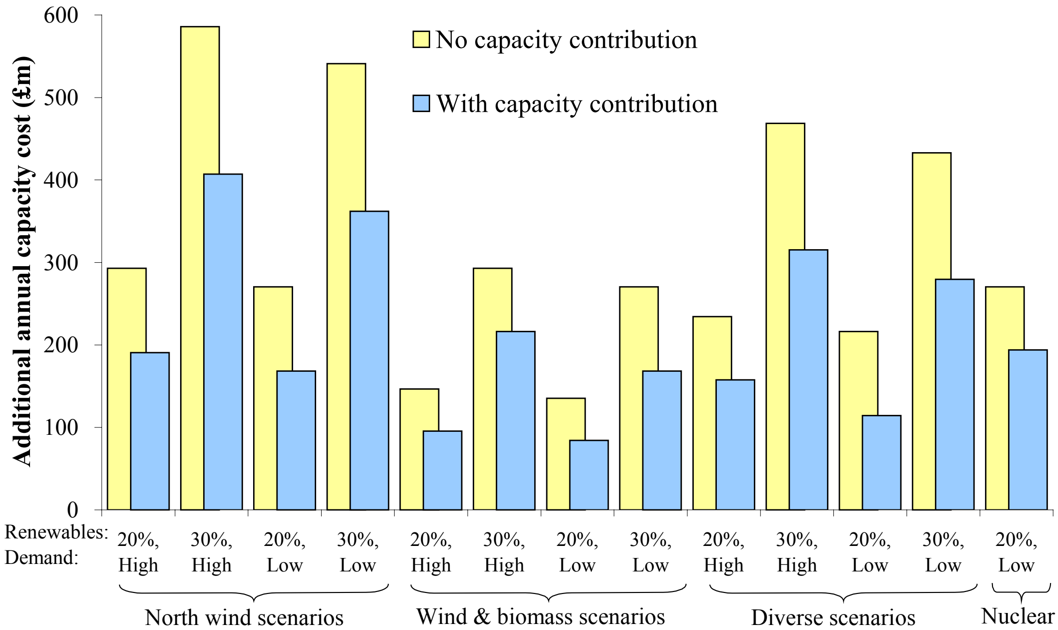
4.21 In Table 10 and Figure 19 we present the additional capacity costs calculated assuming both no contribution from wind to security and the observed level of contribution. In developing the total costs presented in Section 2 and the Executive Summary, we have assumed that there is a capacity contribution from wind.

4.22 Capacity costs are considerable reduced in the *Wind & Biomass* scenarios where only half the generation is from intermittent sources. We have assumed that biomass plant operate baseload with a 66% availability, which provides for two-thirds of the capacity of this technology to be available at winter peak.

Table 10 – Additional annual capacity cost (£m)

Technology	Demand	Renewables	No capacity contribution	With capacity contribution
North Wind	High	20%	293	191
North Wind	High	30%	586	407
North Wind	Low	20%	270	168
North Wind	Low	30%	541	362
Wind & Biomass	High	20%	146	95
Wind & Biomass	High	30%	293	216
Wind & Biomass	Low	20%	135	84
Wind & Biomass	Low	30%	270	168
Diverse	High	20%	234	158
Diverse	High	30%	469	315
Diverse	Low	20%	216	114
Diverse	Low	30%	433	280
Nuclear	Low	20%	270	194

Figure 19 – Additional annual capacity costs (£m)



Alternative sources of system security

4.23 In calculating these costs, we have assumed that conventional generation provides the alternative system security. However, there are other potential providers, including demand interruption, interconnectors, retained older plant and emerging storage and fuel cell technologies.

- Older plant, not required to operate in the energy market, may be maintained to provide system security at a lower cost than building new peaking plant. However, there are a number of limitations to the use of such plant, which we believe would preclude its use:
  - if it were economic to maintain this plant, it would probably operate in the energy market too and therefore not be able to provide reserve;
  - coal plant will be 60 years old by 2020 and may not be sufficiently reliable to provide system security, particularly if operating infrequently; and
  - coal plant take 24 to 36 hours to start from cold, which may reduce the applicable periods that such plant could provide reserve.
- Interconnectors can provide security, and this study has assumed they are utilised for such purposes. However, renewable generation is expanding throughout Europe, driven by the EU renewables directive[17], and large capacities of wind are being deployed across northern Europe, Spain and Italy.

[17] The promotion of electricity produced from renewables sources in the internal electricity market 2001/77/EC.

These developments may reduce the ability of other markets to provide security.

- None of the new technologies are proven to provide system security, but could do so in theory. To be effective, these alternatives would have to be cheaper than the OCGT we have assumed. It has not been possible to cost these alternatives, though current estimates for storage costs are considerably greater than the assumed OCGT cost.

4.24 To assess the viability of voluntary demand-interruption and storage technologies would require the extent of wind interruptions to be quantified. The incidence and duration of widespread no-wind periods need to be quantified. If such periods are of long duration, it may not be possible for storage technologies to bridge the gap and voluntary demand interruptions may be impractical.

System balancing – additional response and reserve requirements

4.25 The key driver for the costs associated with system balancing is the amount of random power fluctuation, caused by unpredictable changes in load and generation, that needs to be accommodated. This section quantifies the costs associated with the need for additional balancing capability to accommodate fluctuations in intermittent renewables (predominantly wind generation).

4.26 In order to maintain a secure and stable operation of the electricity system, demand and generation must be continually balanced. System frequency is the direct measurement of the balance between generation and system demand at any one instant and must be maintained continuously within narrow statutory limits around 50Hz. Frequency falls when demand is greater than generation and rises when generation is greater than demand. The Electricity Supply Regulations require the system frequency to be maintained at ±1% (0.5Hz) of 50Hz, except in abnormal or exceptional circumstances.

4.27 In order to manage frequency effectively, system operators utilise a range of balancing (ancillary) services that operate over different time horizons. In order to continuously maintain system frequency in the time scale of several seconds to several minutes, conventional generators are equipped with appropriate governing systems that control their outputs to neutralise frequency fluctuations – which may arise from changes in demand and generation. This service, known as dynamic response, is automatically delivered by synchronised generators specially selected to operate in frequency-sensitive mode and is primarily provided by pumped storage and part-loaded thermal plant. Generators over 50MW are required to contribute to this service in accordance with the Grid Code. Similar requirements, although somewhat less demanding, are now being imposed on large wind generators by a number of European utilities, including ELTRA[18] from Denmark and Scottish Power[19].

4.28 Over the time horizon of several minutes to several hours, the balance between supply and demand is achieved through a number of reserve services (such synchronised reserve and standing reserve). Both generators and demand can provide standing reserve.

4.29 Fluctuations in the output of renewable generation (such as wind) will place an additional duty on the remaining generating plant and increase the requirements for both response and reserve capacity. The amount of additional resource required to manage unscheduled wind generation will not be on a 'megawatt for megawatt' basis. The key factor here is the diversity – the phenomenon of natural aggregation of individual wind farm outputs. The output of individual wind turbines is generally not highly correlated, particularly when wind farms are located in different regions. This effect is taken into account in our study.

4.30 It is important to stress that response and reserve requirements are not assigned to back up a particular plant type (wind), but to deal with the overall uncertainty in the balance between demand and generation. The uncertainty to be managed is driven by the combined effect of the fluctuations in demand and conventional and renewable generation. These individual fluctuations are generally not correlated, which has an overall smoothing effect with a consequent beneficial impact on the cost.

4.31 The magnitude of these fluctuations will strongly depend on the time horizon considered. Clearly, the forecast error increases as the time horizon over which the prediction is being made becomes longer. Statistical analysis of the fluctuations of wind output over the various time horizons is performed to characterise the uncertainty of wind output. For each of the scenarios, this is carried out using the half-hourly time series of wind. This is a key to assessing the additional resources and their cost necessary to manage the balance between the load and generation in systems with considerable contribution of wind generation.

4.32 In assessing the additional resources required to manage the balance between generation and demand in systems with a large penetration of renewables, a simplified approach has been developed. Two distinct time horizons are selected:

- half hour – relevant for determining response requirements; and
- four hour – relevant for determining reserve requirements.

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18 Specification for Connecting Wind farms to the Transmission Network, 2nd Edition, ELTRA Transmission System Planning, 26 April 2000 (ELT 1999-411a)

19 Transmission Connection Requirements for Wind Farms, Issue No. 1.9, (Draft for consultation, Scottish Grid Code Review Panel.

4.33 Fluctuations associated with lead times above four hours are assumed to be dealt with by bringing additional plant (in case of significant reductions in wind output) or by reducing the number of units on the system (in case of significant increases in wind output). The fluctuations of wind power output, as a percentage of wind capacity installed, over half-hour and four-hour time horizons are shown in Figure 20. Standard deviations[20] of the change in wind output over these time horizons were found to be 1.4% and 9.3% of the total installed wind capacity respectively. If, for example, the installed capacity of wind generation is 10GW, standard deviations of the change in wind generation outputs are 140MW and 930MW over the half-hour and four-hours time horizons respectively. This means that the range of possible changes in wind output in the half-hour time horizon would be about +/-420MW and for time horizon of four hours about +/-2,790MW. The results obtained broadly agree with earlier studies[21, 22, 23]

4.34 Standard deviations of changes in wind output for the two characteristic time horizons (for each of the scenarios), are finally combined with the standard deviations of demand/generation forecast errors to determine the level of the overall fluctuation that need to be managed. This is calculated following the standard statistical approach of combining the independent (uncorrelated) errors (the mean square error of the combination is the sum of the mean square errors)[24].

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20 The standard deviation is a measure of how widely distributed (dispersed) that a set of data points are from the mean (average). Points within one standard deviation are closer to the mean than pints between one or two standard deviations.

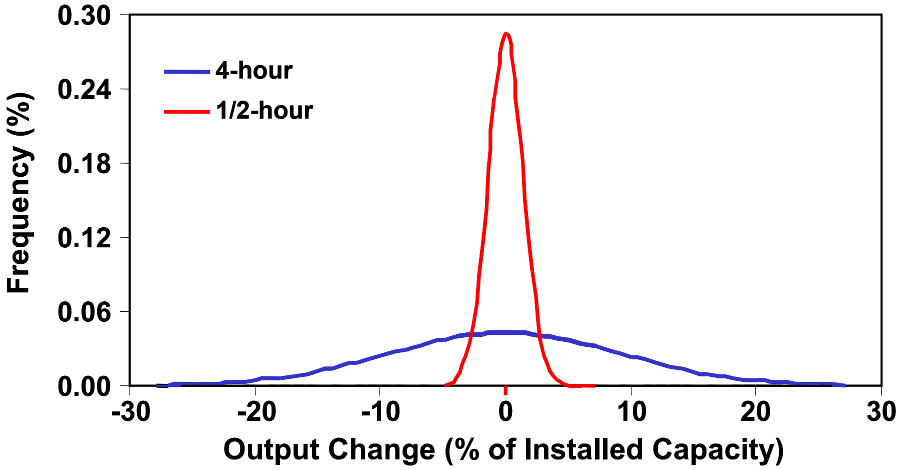
21 Energy Policy Review, Supplementary Submission from National Grid, September 2001 http://www.cabinet-office.gov.uk/innovation/

22 Short-term Power Fluctuation of Wind Turbines: Analysing Data from German 250MW Measurement Program from the Ancillary Services Viewpoint, NREL, July 1999.

23 Eric Hirst, Interaction of Wind Farms with Bulk-Power Operations and markets, Project for Sustainable FERC Energy Policy, September 2001.

24 Assuming that the standard deviation of the forecast error of changes in demand (and conventional generation output) over the time horizon of a half-hour is 340MW and that the standard deviation of change of wind output over the same time horizon is 140MW (for 10GW of installed capacity) the resulting standard deviation of the mismatch between demand and generation is 368MW ($=\sqrt{340^2+140^2}$). This also shows that adding 10GW of wind capacity only marginally increases the standard deviation of the overall fluctuation in the time horizon of half-hour (from 340MW to 368MW).

Figure 20 – Frequency distribution of changes in wind generation output over half-hour and four hour time horizons



4.35 The frequency regulation capacity needed to deal with the uncertainty (separately for response and reserves time scales) is defined as the variation contained within three standard deviations of the overall system fluctuation. This amount of capacity committed to support the regulation will contain 99% of the possible mismatches between demand and supply in the characteristic time horizons (see Figure 20). For the example given in Footnote 24, the system would need be able to absorb fluctuations of +/-3 x 368MW = 1,143MW, in the time horizon of a half-hour.

Response

4.36 One of the factors that determines the amount of response required is system inertia, which controls the initial rate of change of frequency following a disturbance, such as loss of plant. The amount of response required increases with reductions in system demand, as the amount of inertia reduces and the relative impact of disturbances increases. Furthermore, the overall response requirements will be driven by the inertia of generating plant running on the system.

4.37 In this study we have assumed that all generators operating in the system will contribute to the system inertia. We also assumed that new conventional plant connected to the system would have similar inertia characteristics as the existing plant. Regarding renewable generation technologies, it is important to emphasise that generators connected through *power electronic* interfaces, such as doubly-fed induction generators (technology used for large wind installations) will not normally contribute to the overall system inertia. This problem has already been recognised by the industry and manufacturers and there are already proposals to establish adequate converter control strategies to deliver inertia-related effects[25]. We believe that this issue will be resolved satisfactorily in the next few years.

4.38 The amount of dynamic response that a conventional generating unit should provide is specified by the Grid Code. Currently, the Grid Code requires that generators be capable of providing response (primary, secondary and high frequency) at the levels of at least 10% of their installed capacity.

4.39 In order for synchronised conventional plant to provide dynamic response (and reserve) it must run part-loaded. Thermal units operate less efficiently when part-loaded, with an efficiency loss of between 10% and 20%. Since some of the generating units will be part-loaded to provide response, some other units will need to be brought on the system to supply energy that was originally allocated to responsive plant. This usually means that plant with higher marginal cost will need to run, and this is another source of cost. Both of these factors are taken into consideration in the assessment of cost related with providing response services. On average, the overall cost of part-loading conventional plant for provision of response and reserve was found to vary between about £1/MW/h and £3/MW/h for each MW (and hour) of de-load.

4.40 Another component of cost of providing response is associated with increased maintenance and cost of governing equipment. An agreed figure for this cost is £4.5/MW/h and has been routinely used for compensating generators for holding response service. This figure is being adopted in this study.

Reserve

4.41 Reserve requirements are met by both synchronised and standing reserves. Synchronised reserve is provided by part-loaded coal and CCGT plant, while standing reserve is provided by higher fuel cost plant, such as OCGTs and pump storage plant. Following the simplifications adopted, the total requirement for reserve (synchronised and standing) is assumed to be driven by the overall system fluctuations of demand and generation over the four-hour time horizon.

4.42 The allocation of reserve between synchronised and standing plant is a trade-ff between the cost of efficiency losses of part-loaded synchronised plant (plant with relatively low marginal cost) and the cost of running standing plant with relatively high marginal cost. The balance between synchronised and standing reserve is optimised to achieve minimum overall reserve cost.

4.43 Committing part-loaded plant to provide response and reserve requires other units to be started up, before they would otherwise be required. This effect is taken into consideration and the costs of additional start-ups (driven by response and reserve requirements) have been included in the overall balancing cost. The costs of start-

[25] J Ekanayake, L Holdsworth, N Jenkins, Control of Doubly Fed Induction Generators, Tyndall Centre for Climate Change, 2002.

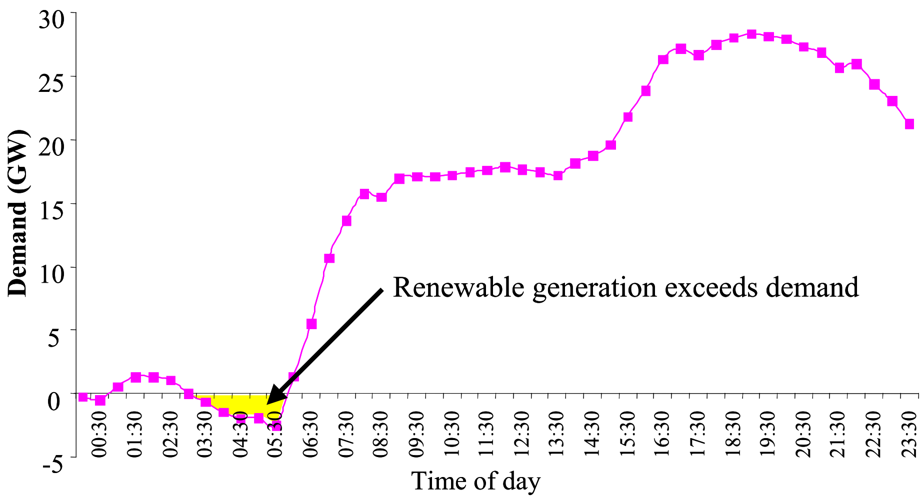
ups are technology and size specific (and depend on the unit down time) and vary between about £3,000 and £15,000 per start up.

Curtailment costs

4.44 When renewable generation reaches 20% or 30% of demand, there will be occasions (generally during low demand days over summer) when the number of conventional units needed to supply the remaining load will be so few, that adequate levels of response and reserve could not be maintained. In extreme situations (in 30% *North Wind* scenario) renewable generation will exceed the demand during some periods. These conditions would generally occur during the periods of low demand coinciding with high output of wind generation. Such a situation is shown in Figure 21 for the 30% *North Wind* scenario, where the net demand becomes negative during the night period. The problem associated with such conditions is the maintenance of sufficient response and reserve capacity on the system[26].

4.45 A number of actions that may be available to deal with such surpluses of generation are identified and prioritised with respect to cost. The least costly options would be to increase demand by additional pumping at the pumped storage facilities, reducing/cutting imports from France and exporting the surplus to Norway and/or to France.

Figure 21 – Demand profile net of renewable generation on a windy day



4.46 If these options are exhausted and the amount of conventional plant on the system is still insufficient to provide adequate response and reserve, wind generation could be de-loaded[27] in order to take part in frequency regulation and reserve

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26 C Chen, G Strbac, X P Zhang, "Evaluating the impact of plant mix on frequency regulation requirements, UPEC 2000, Belfast, Sept 2000

27 De-loaded – required by the system operator to reduce generation.

tasks. It was assumed that wind generators will be able to provide response and reserve at the level of 10% of their output. If there were still some surplus generation left, renewable generation would need to be constrained off, starting with the technologies with the highest marginal cost, such as biomass.

4.47 As can be seen from the results in Table 11, the cost associated with the surplus of generation is significant only in scenarios with 30% penetration of wind and in the Nuclear scenario with 20% of penetration of wind (since there will be considerable amount of nuclear plant operating but not contributing to system balancing and which could not be taken off the system for short periods of time). It is should be pointed out that the Nuclear scenario was deliberately selected to test the cost of operating the system with a mix of inflexible conventional plant and intermittent renewable generation. In the future, however, the flexibility of nuclear generators could be improved and enable this form of generation to take part in the provision of balancing services.

4.48 The studies carried out showed that the ability of the system to maintain dynamic response would be considerably enhanced if pumped-storage facilities were able to provide this service in pumping mode[28]. This is driven by the need to provide regulation at low demand levels, particularly overnight (see Figure 21). Since this solution is likely to be cost-effective, we have assumed that half of the pumps are responsive for baseline scenarios, at a one-off cost of £30m, and all pumps for all other scenarios at a cost of £60m. This capital expenditure has been annualised and included within the response costs provided in Table 11.

4.49 We have utilised two approaches, *simulation* and *analytical*, for quantifying the cost of response (cost of de-load and holding), synchronised reserve (cost of de-load cost), standing reserve (cost of running), additional start-up cost and cost of dealing with generation surplus. Both of these approaches produce consistent results.

- *Simulation* assesses the operation of the system using simulation models of system operation by stepping through time-series data and taking into account a number of dynamic constraints such as start-ups, minimum on and off times, ramp rates, minimum stable generation etc. A combined energy, response and reserve scheduling programme was developed for this purpose. The cost of balancing is estimated by performing a number of simulation studies on six characteristic days covering business and non-business days in winter, spring/autumn and summer seasons. Annual costs were estimated by scaling up these sample days on a time-weighted basis to represent a year.
- *Analytical* uses statistical analysis methods, as used by a number of authors[29].

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28 At present pump-storage plant are only able to provide dynamic response, by altering the level of output, when generating. When in pump mode, the only control is on or off.

29 Energy Policy Review, Supplementary Submission from National Grid, September 2001 http://www.cabinet-office.gov.uk/innovation/

4.50 Our early studies confirmed that both methods were giving acceptably consistent results. Since the analytical approach is considerably less complex and computationally less intensive, the simulation approach was only employed to calibrate the analytical models, which then were employed to run the sensitivity and cost assessments.

Balancing results

4.51 Table 11 presents the additional balancing costs in each of the scenarios. The total costs in the baseline and each of the scenarios are illustrated in Figure 22. Note that system balancing costs, as defined in this study, include operating costs only, while the cost of capacity (fixed cost) associated with provision of these services is not included here and has been dealt with separately, earlier in this section under capacity cost. Figure 22 illustrates the total balancing costs (prior to netting off the baselines). It can be seen that although response costs are the greatest component of total costs in the baselines, they are a far less significant element of the additional costs. In contrast, synchronized reserve costs are the most substantial of the additional balancing costs.

Table 11 – Additional annual balancing costs (£m)

Technology	Demand		Response	Reserve Synchro-nized	Reserve Standing	Start-up	Wind curtail-ment	Total additional balancing
North Wind	High	20%	14	49	13	16	0	93
North Wind	High	30%	31	115	26	33	11	217
North Wind	Low	20%	12	41	12	13	0	77
North Wind	Low	30%	28	104	24	29	11	196
Wind & Biomass	High	20%	7	27	6	7	-	47
Wind & Biomass	High	30%	13	63	12	15	0	103
Wind & Biomass	Low	20%	6	23	5	5	-	40
Wind & Biomass	Low	30%	12	58	11	13	0	93
Diverse	High	20%	11	41	10	13	-	75
Diverse	High	30%	24	95	21	26	4	170
Diverse	Low	20%	10	36	9	11	-	66
Diverse	Low	30%	21	84	19	22	4	150
Nuclear	Low	20%	12	39	11	13	6	82

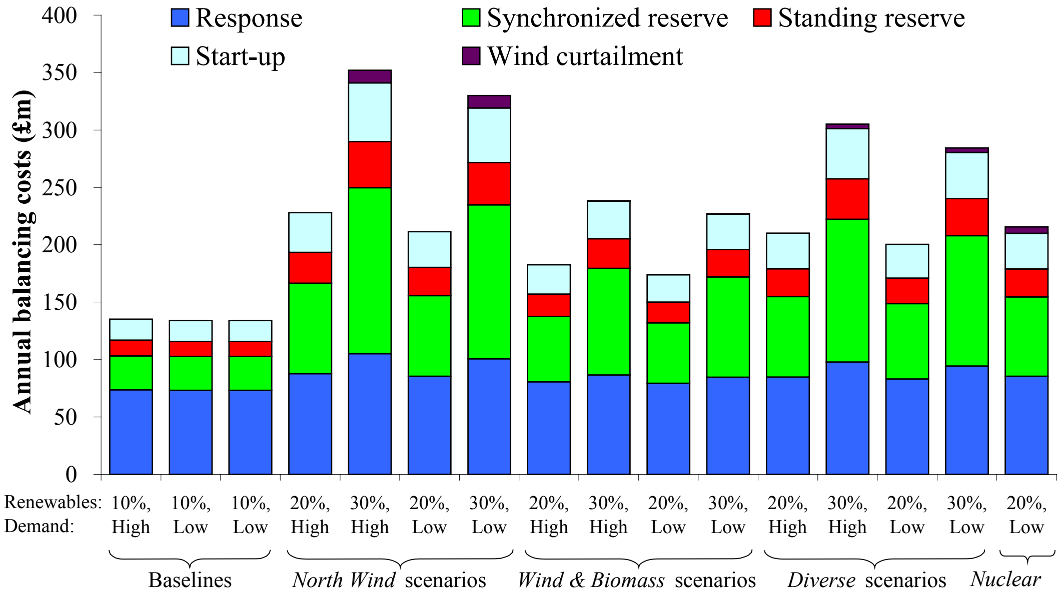
L Dale, NETA & Wind, UMIST, 8 May 2002, Invited presentation

D Farmer at al, Economic and operational implications of a complex of wind-driven generators on a power system, IEE Proceedings, Vol 127, Pt. A, No. 5, June 1980.

M Grubb, Value of variable sources on power system, IEE Proceedings on Generation, Transmission and Distribution, Vol 138, No 2, March 1991.

D Milborrow, Penalties for intermittent renewable resources, Submission to energy policy review, September 2001 http://www.cabinet-office.gov.uk.

Figure 22 – Total annual balancing costs by component for baselines and scenarios



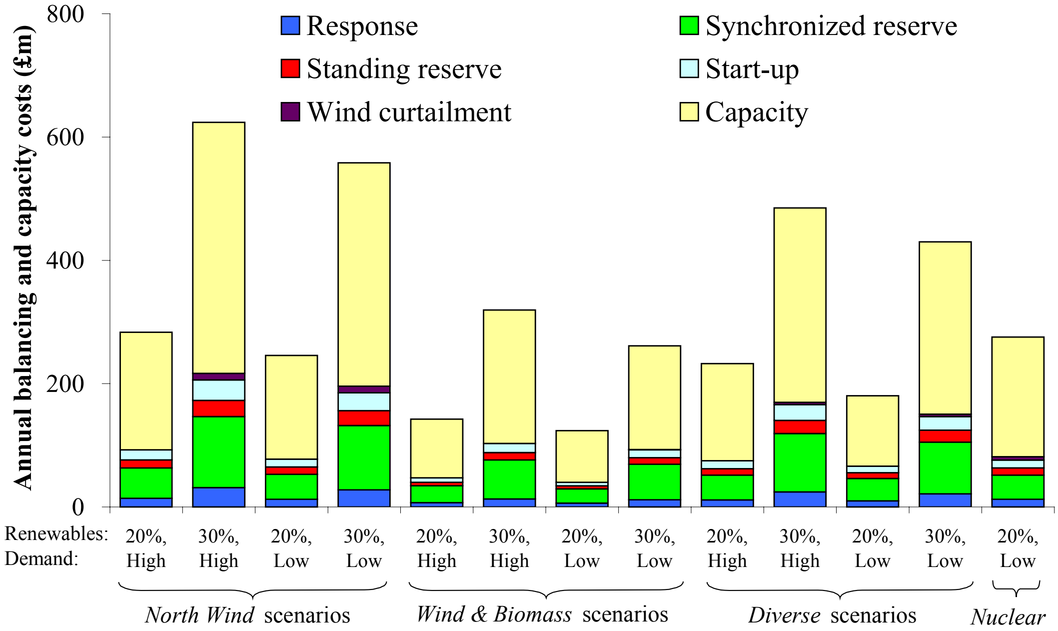
Total balancing and capacity costs

4.52 In Table 12 we combine our projections for the additional balancing and capacity costs. We have utilised our capacity costs including a capacity contribution from wind. It can be seen from Figure 23 that capacity costs dominate the balancing costs.

Table 12 – Additional annual and unit balancing and capacity costs by scenario

Scenario	Demand		Annual Capacity (£m)	Annual Balancing (£m)	Annual Balancing & capacity	Unit costs (£/MWh) by generation All	Additional Renewables	Wind
North Wind	High	20%	191	93	284	0.66	6.64	6.64
North Wind	High	30%	407	217	624	1.46	7.30	7.30
North Wind	Low	20%	168	77	246	0.62	6.23	6.23
North Wind	Low	30%	362	196	558	1.42	7.08	7.08
Wind & Biomass	High	20%	95	47	143	0.33	3.34	6.68
Wind & Biomass	High	30%	216	103	319	0.75	3.74	7.48
Wind & Biomass	Low	20%	84	40	124	0.31	3.14	6.29
Wind & Biomass	Low	30%	168	93	261	0.66	3.31	6.63
Diverse	High	20%	158	75	233	0.54	5.45	6.81
Diverse	High	30%	315	170	485	1.14	5.68	7.10
Diverse	Low	20%	114	66	181	0.46	4.58	5.72
Diverse	Low	30%	280	150	430	1.09	5.45	6.81
Nuclear	Low	20%	194	82	275	0.70	6.98	6.98

Figure 23 – Breakdown of gross annual generation costs by function in each scenario



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5. TRANSMISSION COSTS

Methodology and assumptions

5.1 The existing GB transmission network that provides bulk power transport operates at voltages of 132kV, 275kV and 400kV. If the massive onshore and offshore wind resources in the UK are to be exploited for generation, an adequate transmission network will become critically important. This raises the question as to what reinforcements on the existing transmission network would be needed in order for this power to be transported to load centres.

5.2 On the other hand, the large-scale penetration of smaller-scale, widely distributed generation may reduce the amount of energy transported over the transmission network. However, the need for transmission capacity may not reduce proportionally, due to its importance in maintaining system security.

5.3 The location of new conventional generation and of decommissioned plant will also have a considerable impact on the future needs for transmission capacity.

5.4 In this study, we have assumed that currently planned transmission network reinforcements will be completed, including the North Yorkshire line, relevant for enhancing the transfer capability between Scotland and England. We have also added an additional 400kV circuit between Beauly to Bonnybridge in the SSE network, which is currently being considered by SSE[30]. This additional reinforcement was driven by expected levels of wind generation in Scotland in the baseline scenarios.

5.5 In Scotland, the 132kV network is classed as transmission, whilst in England and Wales, this is regarded as distribution. For consistency, this study has assumed that all 132kV network costs are within distribution (and are considered in Section 6).

5.6 The key to assessing future needs for transmission facilities (including both circuits and compensation equipment) is to study characteristic patterns of flows on the NGC and Scottish networks for various future scenarios and loading conditions. We have therefore developed a full AC transmission network model of the 2020 GB system to examine its performance for various conditions. Useful indicators of the extent of required reinforcements are power transfers across the main system boundaries, presented in Figure 24. Indicative maximum power transfer limits across these boundaries are given in Figure 24 (in MW) [31]. These

30 "£200 million network investment to liberate Scottish renewable energy potential" Press Release. SSE 26 September 2002.

31 Concept study – Western off-shore transmission grid. PB Power report to ETSU, 2002.

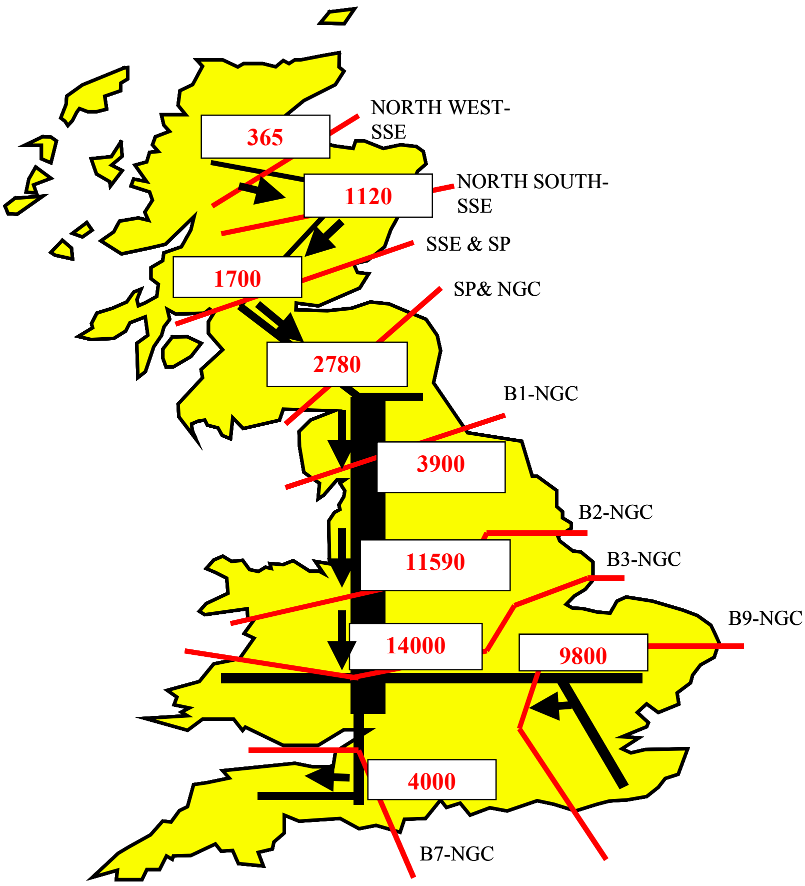
are however not static and will depend on the actual generation configuration and loading conditions.

5.7 An important reference point for this work is the Renewable Energy Transmission Study (RETS), recently completed by SP Transmission and Distribution, Scottish and Southern Energy and National Grid Company. The RETS study proposes a strategy for transmission development capable of accommodating 2GW-6GW of wind generation in Scotland.

5.8 It is important to bear in mind that the RETS study was performed against a 2010 background, with a larger amount of conventional plant being present in the Scottish networks than is assumed in this study for 2020.

5.9 For each of the scenarios, wind and other renewable generation was distributed to five favourable locations within each GSP group, following the regional allocation assessments. The locations are selected to minimise the need for transmission reinforcement. The cost of getting dispersed renewable resource from remote areas onto the main transmission network is not explicitly included but may be significant. For example, the cost of connecting renewable resource from the Western Isles in Scotland to the transmission system may be considerable, as indicated in the RETS study. However these are treated as connections and hence are not considered in this study.

Figure 24 – Present power transfer limits on the main system boundaries (MW)



5.10 Similarly, new conventional generation was also located to corresponding GSP groups, making use of existing sites where (as discussed in paragraph 3.12).

5.11 A significant amount of new conventional generation was allocated to the NGC system in favourable locations, while 2GW of such plant was connected to the SP system, which resulted in a minimum infrastructure reinforcement on the GB network.

5.12 For the purpose of assessing the required transmission capacity, several critical conditions are studied. These include coincidence of:

- maximum demand and maximum wind generation output;
- maximum demand and minimum wind generation output; and
- minimum demand and maximum wind generation output.

In cases with maximum and minimum wind conditions, the outputs of wind generation are set at a level of 83% and 10% of capacity respectively, to account for diversity.

5.13 For each of the scenarios, a comprehensive contingency assessment (N-2) [32] is performed to ensure that proposed reinforcement will satisfy present transmission planning standards.

5.14 Table 13 summarises the modelled maximum power transfers and the transfer limits across the critical system boundaries on the present GB network for the 2020 generation configuration. Where the modelled power transfers exceed the limits (shown in red in Table 13), is indicative of reinforcement required to the transmission network in each of the scenarios. Note that the flows across boundaries B7 and B9 are not explicitly shown since they are considerably below their corresponding maximum limits. The results of these studies show that a considerable transmission reinforcement is required if a significant amount of wind generation is to be connected in Scotland. A summary of transmission reinforcements is listed in Annex E.

5.15 The flows across the main system boundaries (Table 13) clearly indicate that the considerable transmission reinforcement is required in North-Wind Scenarios. Significant reinforcement is needed not only in Scottish networks but also deep in the NGC system, as the North-South flows (flows across the interconnector and boundaries B1 and B2) are large. On the other hand, in the Wind & Biomass

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32 The level of required security provided by the transmission network is defined by S*ecurity Standards* which, broadly speaking, define a set of events that the transmission system must be able to withstand. For example, a so-called "N-2 security standard" would require the system to work satisfactorily following a loss of any *two* of its N elements (circuits). In order to achieve this, the loading on the transmission system under normal operating conditions must be limited to levels that permit any credible outage to occur without causing overloads of the remaining circuits, violations of power quality limits or undermining system stability.

scenarios the additional reinforcement of transmission network required is minimal, since the renewable sources are widely distributed across the system. Observe that the flows across boundaries B1 and B2 are negative in these scenarios, indicating that power flows from South to North (rather than from North to South), and that these flows are significantly below their limits. In the Diverse scenario, the need for the need for reinforcement is primarily driven by locations of wind generation in Scotland.

Table 13 – Modelled power transfers and limits on the critical transmission boundaries

Scenarios	**Demand / Renewables**	**SP & SSE (MW)**	**SP & NGC (MW)**	**B1-NGC (MW)**	**B2-NGC (MW)**	**B3-NGC (MW)**
Baseline	High 10%	2,379	-156	-218	6,334	6,264
Baseline	Low 10%	2,397	246	255	5,785	6,472
Nuclear baseline	Low 10%	2,452	809	1,080	9,056	6,963
North Wind	High 20%	5,473	3,877	4,074	10,728	9,553
North Wind	High 30%	8,602	7,702	7,870	14,413	12,083
North Wind	Low 20%	5,216	3,889	3,446	9,218	8,772
North Wind	Low 30%	7,794	7,043	6,764	12,374	10,780
Wind & Biomass	High 20%	2,276	-361	-260	6,768	6,744
Wind & Biomass	High 30%	2,148	-619	-1,200	4,907	4,725
Wind & Biomass	Low 20%	2,283	19	-564	5,403	5,995
Wind & Biomass	Low 30%	2,169	-208	-596	5,094	4,284
Diverse	High 20%	3,745	1,452	1,889	7,634	7,666
Diverse	High 30%	5,043	2,931	3,737	8,017	7,811
Diverse	Low 20%	3,640	1,692	1,436	6,527	7,071
Nuclear	Low 20%	5,256	4,390	4,796	12,457	9,629
Power transfer limits		1,700	2,780	3,900	11,590	14,000

5.16 For each of the scenarios, two reinforcement strategies are assessed:

- *least-cost reinforcement* that includes reconducturing of 275kV circuits that needed to be reinforced; and
- *engineering-based reinforcement*, a more practical (and robust) solution in which all 275kV circuits that needed to be reinforced are upgraded to 400kV.

5.17 Upgrades of circuits to higher voltage levels are accompanied with corresponding upgrades of substations connected to the circuit, which is included in costing of reinforcements. The detailed list of reinforcements presented in Annex E assumes that the latter robust approach is adopted (as this results in the lowest additional costs, for reasons explained in paragraph 5.20).

5.18 Although the primary focus of the studies was on steady state conditions, a considerable amount of reactive compensation equipment is allocated to enhance the dynamic performance of the network, particularly because of the limited amount of conventional generation located in Scotland. We have also assumed that allocated reactive power support devices will provide dynamic voltage support similar to those of synchronous generators. For achieving the satisfactorily dynamic performance of the system, the ability of both renewable and conventional generators to remain stable under fault conditions on the transmission network will be of paramount importance. We have assumed that the electrical characteristic of future renewable generators will be similar to those of conventional synchronised plant and have the ability to remain operating during faults on the transmission network, although, at present, there are a number of technical challenges to be resolved. Recent studies indicate that generator technologies selected for large wind installations (doubly-fed induction generators) have the potential for achieving desirable performance during network disturbances[33]. However, detailed studies on the GB transmission system will be required to confirm that the dynamic and transient stability of the system can be reliably maintained for particular configurations.

[33] L Holdsworth, N Jenkins, G Strbac, Electrical stability of large offshore wind farms, Proceedings of IEE Seventh International Conference on AC-DC power Transmission, November 2001.

L Holdsworth, X Wu, J Ekanayake, N Jenkins, Comparison of Fixed Speed and Doubly Fed Induction Wind Turbines During Power System Disturbances, http://www.tyndall.ac.uk (submitted to IEE Proceedings on Generation, Transmission and Distribution)

Results

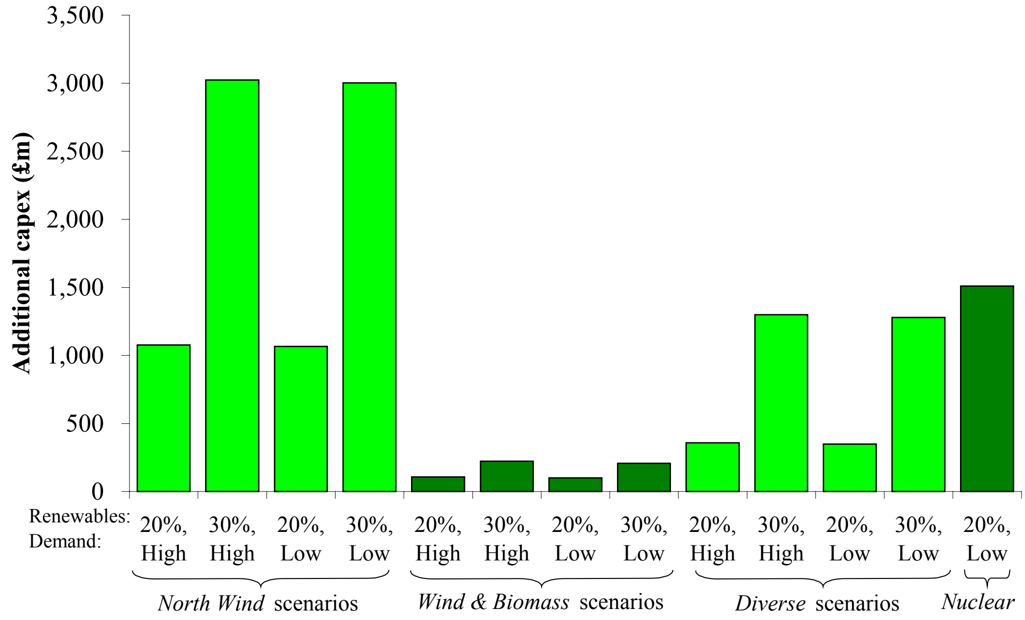
Transmission reinforcement

5.19 The additional transmission costs are presented in Table 14 and Figure 25, calculated on the robust engineering basis. The results for the least-cost approach are discussed below.

Table 14 – Total and additional transmission reinforcement costs by scenario (£m)

Scenario	Demand	Renewables	Total reinforcement capex	Additional reinforcement capex	Annualised additional cost
Baselines	High	10%	1,285		
Baselines	Low	10%	1,275		
Baselines	Low	10%	1,275		
North Wind	High	20%	2,362	1,077	69
North Wind	High	30%	4,310	3,025	195
North Wind	Low	20%	2,341	1,066	69
North Wind	Low	30%	4,278	3,003	194
Wind & Biomass	High	20%	1,393	108	7
Wind & Biomass	High	30%	1,508	223	14
Wind & Biomass	Low	20%	1,375	100	6
Wind & Biomass	Low	30%	1,482	208	13
Diverse	High	20%	1,643	358	23
Diverse	High	30%	2,584	1,299	84
Diverse	Low	20%	1,623	348	22
Diverse	Low	30%	2,554	1,279	30
Nuclear	Low	20%	2,784	1,509	97

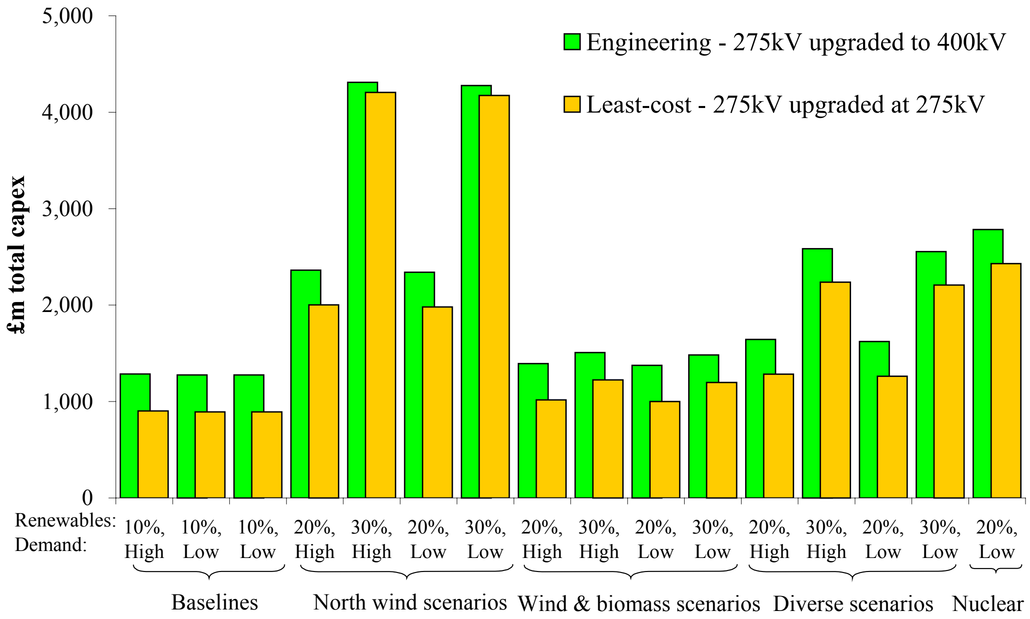
Figure 25 – Additional transmission capital expenditure on reinforcement by scenario



Engineering solutions vs. least-cost investments

5.20 On total cost, the least-cost approach (described in paragraph 5.16) saves, on average, 15% of the investment cost (see Figure 26). However, as much of this saving occurs only in the baselines, the additional costs of moving to 20% or 30% renewables are actually higher under this approach

Figure 26 – Total transmission capital expenditure under the two costing methods

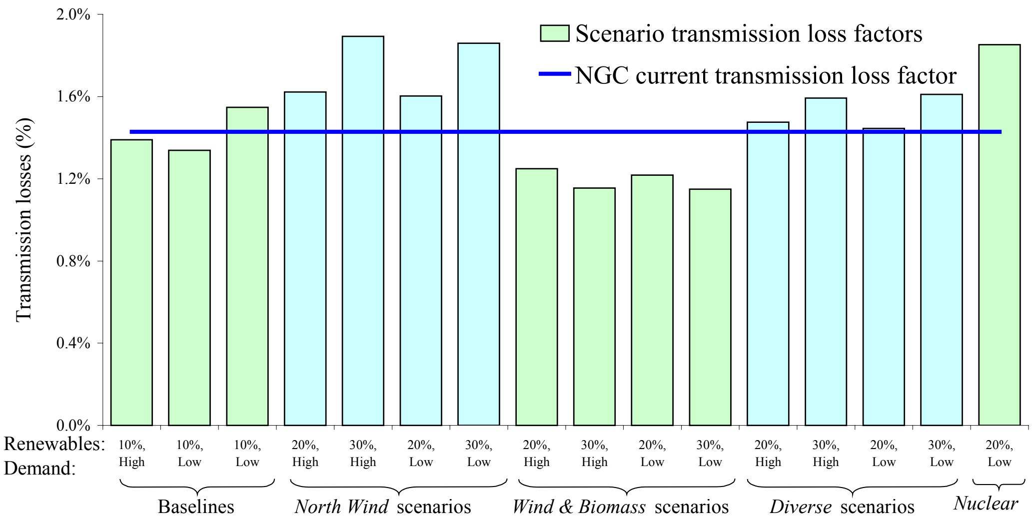


5.21 We have therefore adopted the more robust engineering solution instead of the least-cost approach to calculating transmission reinforcement costs.

Transmission losses

5.22 In order to assess annual energy losses in the transmission network associated with different scenarios, a number of power flow studies, characterising different loading conditions, were carried out. Results of this analysis are presented in Figure 27. As expected, transmission losses in the *North Wind* scenarios are the greatest, reaching a level of about 8TWh per year in the scenarios with 30% penetration of renewable generation. On the other hand, in the *Wind & Biomass* scenarios, transmission losses are found to be significantly less – about 4.5TWh per annum with 30% penetration. This is lower than in the base cases and the present loss factor on NGC's system. The introduction of additional renewables in line with the *Wind & Biomass* scenarios, could have a beneficial impact, lowering transmission losses.

Figure 27 – Transmission loss factors in baseline and scenarios compared to current losses on NGC's system[34]



5.23 In Table 15 we calculate the total cost of losses as being between £100m and £178m per annum, assuming a wholesale price of £22/MWh in 2020. To set this cost in context, the equivalent costs of present losses on the NGC system are £80m, but this is based on a wholesale price of £18/MWh and s smaller system where demand is 16% to 23% less than in the 2020 scenarios.

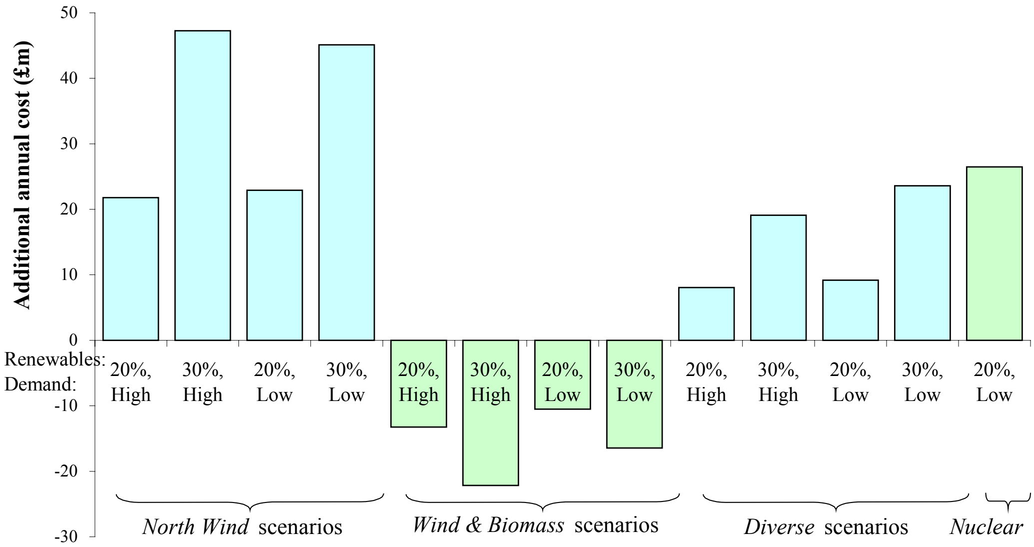
34 The current loss factor on the NGC system is shown to provide a context for the scenario values. NGC's loss factor is calculated on the same basis as the scenario losses, from losses of 4.7TWh on demand of 329TWh.

5.24 Table 16 and Figure 28 illustrate the additional costs of transmission losses, which are negative for the *Wind & Biomass* scenarios.

Table 15 – Total volume and costs of transmission losses

Technology	Demand	Renewables	Losses (TWh)	Demand (TWh)	Loss Factor	Cost (£m)
Baselines	High	10%	5.9	427	1.4%	131
Baselines	Low	10%	5.3	394	1.3%	116
Baselines	Low	10%	6.1	394	1.5%	134
North Wind	High	20%	6.9	427	1.6%	152
North Wind	High	30%	8.1	427	1.9%	178
North Wind	Low	20%	6.3	394	1.6%	139
North Wind	Low	30%	7.3	394	1.9%	161
Wind & Biomass	High	20%	5.3	427	1.2%	117
Wind & Biomass	High	30%	4.9	427	1.2%	108
Wind & Biomass	Low	20%	4.8	394	1.2%	106
Wind & Biomass	Low	30%	4.5	394	1.1%	100
Diverse	High	20%	6.3	427	1.5%	139
Diverse	High	30%	6.8	427	1.6%	150
Diverse	Low	20%	5.7	394	1.4%	125
Diverse	Low	30%	6.4	394	1.6%	140
Nuclear	Low	20%	7.3	394	1.9%	161
Current NGC		2%	4.7	329	1.4%	85

Figure 28 – Additional cost of transmission losses



Total transmission costs

5.25 In Table 16 we combine our projections for the additional costs of transmission reinforcement and losses. The combined additional costs are also illustrated as unit costs, calculated over all generation and over the additional renewable and all additional wind generation. The negative additional costs of losses in the *Wind & Biomass* scenarios are sufficient to offset the low additional reinforcement costs, reducing these combined transmission costs to approximately zero. Although the values shown for *Wind & Biomass* scenarios in Table 16 are negative, within the degrees of confidence of this study, it may not be prudent to describe these values as demonstrating a net benefit.

Table 16 – Addition annual transmission reinforcement and losses costs

Scenario	Demand	Renewables	Annualised reinforce-ment costs	Annual losses costs	Combined annual costs	Unit costs (£/MWh) by generation All	Additional Renewables	Additional Wind
North Wind	High	20%	69	22	91	0.21	2.14	2.14
North Wind	High	30%	195	47	242	0.57	2.84	2.84
North Wind	Low	20%	69	23	92	0.23	2.33	2.33
North Wind	Low	30%	194	45	239	0.61	3.03	3.03
Wind & Biomass	High	20%	7	-13	-6	-0.01	-0.15	-0.30
Wind & Biomass	High	30%	14	-22	-8	-0.02	-0.09	-0.18
Wind & Biomass	Low	20%	6	-11	-4	-0.01	-0.10	-0.21
Wind & Biomass	Low	30%	13	-16	-3	-0.01	-0.04	-0.08
Diverse	High	20%	23	8	31	0.07	0.73	0.91
Diverse	High	30%	84	19	103	0.24	1.21	1.51
Diverse	Low	20%	22	9	32	0.08	0.80	1.00
Diverse	Low	30%	30	24	106	0.27	1.35	1.68
Nuclear	Low	20%	97	26	124	0.31	3.14	3.14

6. DISTRIBUTION COSTS

6.1 The section describes the key results and findings for additional distribution system costs. This section considers reinforcement and network management costs but does not cover distribution losses. A detailed description of the assumptions and methodology is included in Annex F.

Background and definition of the distribution problem

6.2 It is expected that a large proportion of the new renewable generation will be connected to the distribution networks. The work in this study considers the impact on the GB distribution networks of connecting, and operating significant amounts of generation at the distribution level.

6.3 The work focuses on the capital investment requirements associated with network reinforcements. Some thoughts are, however, provided on the impact which large amounts of distributed generation may have on the day-to-day operation of the distribution networks.

Approach to work and methodology

6.4 The sheer size and complexity of the distribution networks in England, Wales and Scotland means that full and detailed modelling of the GB distribution networks was not appropriate given the project terms of reference of providing *order of magnitude* costs.

6.5 The approach taken to the work is described below. The methodology employed was considered to be appropriate and also consistent with the project terms of reference, both by the project team and by the distribution review group[35].

Common characteristics of the GB distribution networks

6.6 In terms of fundamental design rationale, basic electrical characteristics and operational attributes, all fourteen of the distribution areas considered have strong similarities. This is an unsurprising product of the evolution of the power networks in Great Britain over the last 50 years. In this work, these similarities are exploited in order that a relatively simple, yet credible, methodology can be used. This approach is described below.

35 The Distribution Review Group was established to agree methodology and key assumptions for the study. This was pivotal to the success of the project given the number of important assumptions needed for the analysis. Membership of the Distribution Review Group is given in Annex A.

The method is predominantly based on the number of substations in each area

6.7 An output from the scenario development elements of the project is the allocation of generation capacity[36] to each distribution geographic area for each of the three baselines and 13 renewable scenarios. This information was taken as an input to the distribution costing section of the project.

6.8 The distribution analysis is 'substation based' in that it assesses the amount of generation capacity, on average, that can be connected per substation in each distribution area. Once the total generation per substation has been reached, the analysis assesses the reinforcement required in order to accommodate the target amount of generation – according to a standard set of reinforcement solutions.

A representative distribution network model is used

6.9 In distribution networks, power is transferred through a number of well-defined system levels which operate at different, standard voltages. A distribution company may have five or six discrete voltage levels in its distribution network. Whilst many of the voltages are common across all distribution areas[37], there are some voltage levels which can be found in some distribution area but not in others.

6.10 For the purposes of the analysis in this study, a simplified three voltage level network was used for all distribution areas. This is detailed further as part of the description of assumptions below.

The system reinforcement 'triggers' are well defined

6.11 The technical limitations and operational challenges associated with the connection of generation to distribution networks are common across and clearly understood within the industry.

6.12 Whilst there may be a multitude of technical considerations associated with the connection of increased levels of renewable, or other distributed, generation, the industry recognises[38] the two[39] main technical barriers as being:

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36 In this study, the generation capacity connected to the distribution networks is not all renewable generation. The 2020 baseline scenarios include 10GW of distribution connected CHP plant.

37 For example, all distribution companies in GB operate part of their network at 'grid' voltage – 132kV. Similarly, all companies have an 11kV and a 230/400V network – these are standard UK voltage levels at which end customers are connected and supplied.

38 This is generally acknowledged throughout the electricity supply industry – both from generator developers and distribution network operators. The study's Distribution Review Group concurred with this assertion.

39 Thermal rating of equipment can also, occasionally, represent a technical challenge – although such issues often arise allied to a voltage management problem.

- voltage management issues; and
- system fault level issues.

6.13 It is these two issues which most frequently limit the amount of generation which can be connected to distribution networks and, consequently, usually define the network reinforcement 'triggers'. These triggers, along with the reinforcement solutions adopted in the analysis, are considered and discussed further in Annex F.

Determining reinforcement costs

6.14 A spreadsheet model was developed to analyse and determine the costs associated with reinforcing the distribution networks. The model provides for a range of independent input parameters and assumptions for each of the fourteen Distribution Network Operator (DNO) areas. These include:

- total number of substations at each voltage level;
- information on the fault level headroom at each voltage level;
- percentage of land area available for renewable generation deployment;
- percentage of total CHP generation which is exported onto the network;
- typical transformer sizes at each voltage level; and
- amount of distribution-connected generation for each of the scenarios.

6.15 Provision is also made for details of global assumptions which may apply GB-wide. These include:

- generator project sizes for each technology type by scenario;
- maximum permitted aggregate generator capacity at each system voltage level (for the purposes of assessing voltage management limits);
- the extent to which generation connected at one voltage level contributes to the fault level at the next system voltage level;
- proportion of costs attributed to circuit reinforcement for each generator size and at each voltage level; and
- the unit costs of substations, switchboards, lines and cables for the quantification of total reinforcement costs.

6.16 Calculation sheets carry out detailed analysis for each DNO by scenario and the full detailed results are pasted to a summary output sheet.

Description of assumptions

6.17 Given the approach to the quantification, there are a number of important assumptions, which form the basis of the analysis. All of the key assumptions for the work were discussed and agreed with the Distribution Review Group.

High level assumptions

6.18 The approach to the work, as described above, necessitated a number of high level, key, assumptions to be made. These are discussed below.

All of the renewable generation is connected to 'rural' substations

6.19 It is assumed that the nature of the majority of renewable generation will be deployed in rural or semi-rural areas. These generators will be connected – either directly or indirectly – to the more rural[40] 'primary'[41] DNO substations.

Not all of the land area served by each substation is available for renewable generation development

6.20 Local planning and consent restrictions and the location and availability of renewable resource are likely to mean that not all of the land area will be available for development renewable generation.

6.21 The analysis assumes that 70% of the land area served by the currently existing rural primary substations will be available for generation development. The main consequence of this assumption is that each substation will be required to accommodate more of the deployed generation, and hence increase the number of new substations required.

6.22 This effect will be particularly marked during the period between now and 2010. All new substations built between now and 2010 are assumed to be built in areas suitable for renewable development, and will often be sufficient to cover a sizeable part of additional generation connected between 2010 and 2020. For the purposes of this study (establishing approximate system costs for the period after 2010), the effect of restricting the currently available land area will be most noticeable in those regions that would require very little distribution system strengthening prior to 2010.

The distribution networks comprise three voltage levels

6.23 The distribution networks were represented using a simplified three voltage level system. These were:

- 132kV;
- 33kV; and
- 11kV.

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40 Each DNO provided the number of primary substations which it considered to be 'rural'. The DNOs were left to decide themselves how 'rural' was defined. Some DNOs examined the ratio of the aggregate number of pole-mounted (rural) to ground-mounted (urban) transformers connected to each primary substation.

41 A primary substation is defined as being one that transforms down to 11kV. This is most commonly the 33/11kV substations.

6.24 The generation capacity was allocated to either the circuits at one of these three voltage levels or directly to the substations between them – either 132/33kV substations[42] or the 33/11kV, 'primary', substations.

6.25 In providing substation numbers, each of the DNOs re-allocated any other substation types into one of these two generic types – depending upon its use and distribution characteristics. For example, DNOs with 66kV voltage level whose characteristics were similar to a 33kV distribution level included any 66/11kV substations into the 33/11kV 'basket' – and so on.

Transmission connection of all offshore wind

6.26 The assessment of distribution costs assumes that all offshore wind schemes are connected to the transmission network because of their larger size[43]. It is assumed that the cost of connection in such cases will fall to the generation developer and will not be included in the total system costs explored in this piece of work.

6.27 We undertook sensitivity analysis to assess the impact on system costs of connecting offshore wind to the distribution network. This is discussed further under the results heading.

No inter-dependency between the three voltage levels for voltage issues.

6.28 The maximum aggregate generation capacity rule was applied to each voltage level independently. Since this rule is aimed mainly at voltage management issues and since voltage management problems are usually most acute at the voltage at which the generator is connected, this assumption was considered acceptable and appropriate.

Dependency between voltage levels for the assessment of fault level contribution

6.29 For fault level considerations, the contribution to system fault level from distributed generation connected at other voltage levels than the one being considered, can be significant and is considered in this study.

Generation connected at low voltage[44] does not give rise to reinforcement costs

6.30 It is assumed that the design and characteristics of the low voltage network mean that any generation connected at this level will have no material impact upon system reinforcement costs in general.

6.31 Domestic CHP and other micro-generators connected at low voltage are considered only in their impact on total system demand.

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42 132/33kV substations are known as 'Grid' substations or, in some DNOs 'supply points'.

43 This refers to the 275kV and 400kV systems in England and Wales and in Scotland.

44 Low voltage is 230V single phase or 400V three phase.

Scottish 132kV network is included

6.32 It was decided within the group that the 132kV system in Scotland, although treated as transmission in the Scottish companies, should form part of the distribution reinforcement. This assumption was coordinated with the transmission reinforcement study in order to ensure that there was no degree of double-counting of costs.

Shallow connection policy is applied

6.33 In calculating circuit reinforcement costs, a shallow connection policy was assumed. This is consistent with the treatment of transmission costs and reflects the present thinking of Ofgem on the development of distribution connection policy.

6.34 Shallow connection assumes that the generation developer pays only for the new connection assets required to connect to the nearest suitable point on the network and not for any upstream reinforcements which may arise as a result of the connection[45].

6.35 This approach is not a reflection of the relative merits of shallow or deep charging for connection. It is merely a device to separate 'project' costs from 'system' costs for the purpose of this analysis.

Costs are limited to new substation build, replacement switchboards and circuit reinforcement costs

6.36 It is assumed that the total costs comprise these three elements only. The only exception to this is in the assessment of the impact of active network voltage management where the calculation of total costs for each scenario includes provision for the costs of installing various items of equipment required for active network management.

Detailed assumptions

6.37 Some of the more detailed modelling assumptions adopted in the analysis are set out in Annex F.

[45] The inclusion in the connection costs of upstream system reinforcement reflects the present 'deep' connection policy applied to the connection of distributed generation.

Distribution results

6.38 Table 17 and Figure 29 show the additional distribution system costs associated with each of the 2020 deployment scenarios. The highest costs are incurred in the *North Wind* and *Diverse* scenarios and the costs of meeting the 30% target are over twice the costs of the 20% targets, for these scenarios.

6.39 These results assume a uniform deployment of generation across each DNO area. They do, however, recognise that only a proportion of the land served by the substations may be available for renewable generation development (see paragraph 6.21)

Table 17 – Additional total, annualised and unit distribution costs by scenario

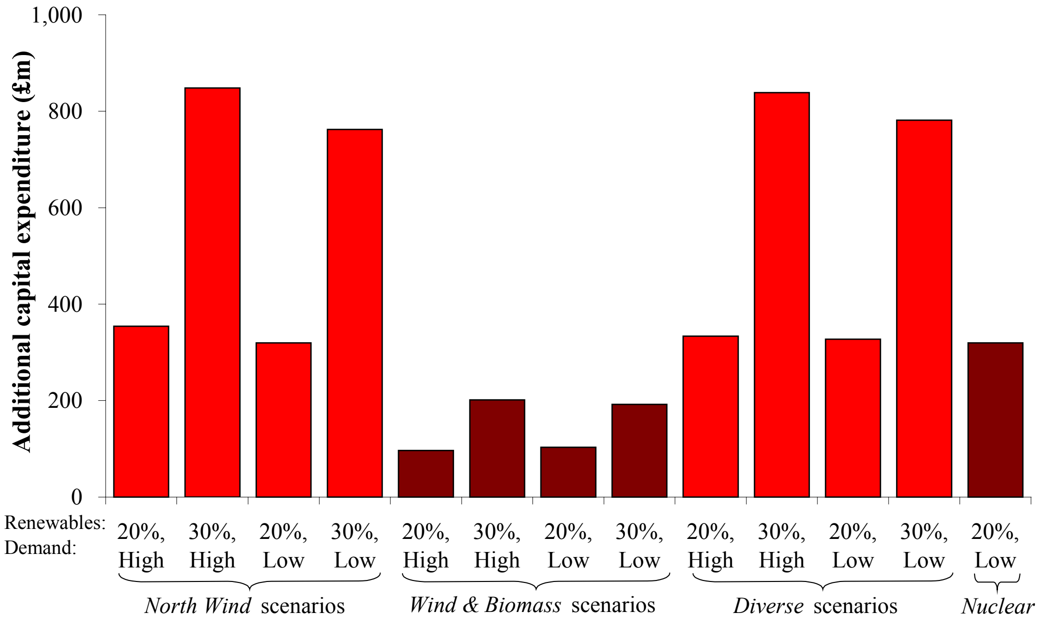
Scenario	Demand	Renewables	Capital cost (£m)	Annual-ised cost (£m)	Unit costs (£/MWh) by generation: All	Additional Renewables	Wind
North Wind	High	20%	354	23	0.05	0.54	0.54
North Wind	High	30%	848	55	0.13	0.64	0.64
North Wind	Low	20%	320	21	0.05	0.52	0.52
North Wind	Low	30%	762	49	0.12	0.62	0.62
Wind & Biomass	High	20%	97	6	0.01	0.15	0.29
Wind & Biomass	High	30%	201	13	0.03	0.15	0.30
Wind & Biomass	Low	20%	103	7	0.02	0.17	0.34
Wind & Biomass	Low	30%	192	12	0.03	0.16	0.31
Diverse	High	20%	334	22	0.05	0.50	0.63
Diverse	High	30%	839	54	0.13	0.63	0.79
Diverse	Low	20%	328	21	0.05	0.54	0.67
Diverse	Low	30%	782	50	0.13	0.64	0.80
Nuclear	Low	20%	320	21	0.05	0.52	0.52

The additional costs of accommodating 20% renewables in the *Wind & Biomass* scenario are higher in the low demand case than those in the high demand case. This is due to higher costs being incurred in the high demand baseline, than in the low demand case. It should be borne in mind that the £6m differential identified here is likely to be within the error factor for this study, and so no significance should be placed on this result.

Distribution losses

6.40 It has not been possible, from the approach adopted, to model the impact of additional renewables on distribution losses. Distribution losses vary with the specific location of individual generators, and so quantifying the impact on losses of generic new projects is extremely complex. New distributed generation in some locations can reduce losses, whilst in other network locations may increases losses. Therefore, it is not possible, at this stage, to take a view on whether additional renewables by 2020 will increase or decrease distribution losses.

Figure 29 – Additional distribution capital expenditure



Comparison with the costs associated with reaching 2010 targets

6.41 To set the 2020 additional capital expenditure in context, we discuss below the likely expenditure to meet the 2010 targets. The analysis of costs for meeting the 20% or 30% renewables, presented above, assumes that the 10% renewables and 10GW CHP targets for 2010 are achieved. ILEX analysis shows that the costs of meeting the 2010 targets is likely to be total capital expenditure of £611m. It should be noted that the costs of achieving 2010 targets assumes an increase in distributed generation of approximately 15GW[46].

6.42 It follows that extending the level of renewable penetration to 20% would see an increase in distribution costs of approximately half that which arises from the present renewables and CHP targets for 2010.

Sensitivity studies

6.43 As part of the analysis, the model was used to run a number of sensitivity studies. These include the effect on total additional distribution costs of:

- including offshore wind as distribution-connected;
- assuming that half of the onshore wind in Scotland is transmission-connected and therefore excludes distribution costs;

[46] This comprises approximately 10GW of renewable generation capacity plus 5GW of CHP capacity.

- *clustering* of renewable generation;
- employing active voltage management;
- changes to the assumed generator plant size; and
- changes to the assumed availability of land area for renewable deployment.

The effects of assuming that offshore wind is distribution connected

6.44 In the analysis and results presented above, we have assumed that all offshore wind is transmission-connected. Figure 30 shows the effect of assuming that offshore wind is distribution-connected. It can be seen that the costs increase significantly, particularly in the 30% *North Wind* and *Wind & Biomass* scenarios.

6.45 The majority of the large increase in total costs seen for the *Wind & Biomass* 30% (high demand) scenario can be attributed to a small number of DNO areas. Under this scenario, the Welsh and Eastern distribution areas all have a high proportion of offshore wind[47].

6.46 There is no consequential decrease, or change, to transmission costs under this sensitivity, as power flows on the transmission network would be unchanged and the transmission connection costs do not form part of the system costs considered in this study. However, there may be a decrease in the *project* costs paid by developers, if connection to the distribution system was over a shorter distance than it might otherwise have to be.

The effects of connecting half of the Scottish onshore wind to the transmission system

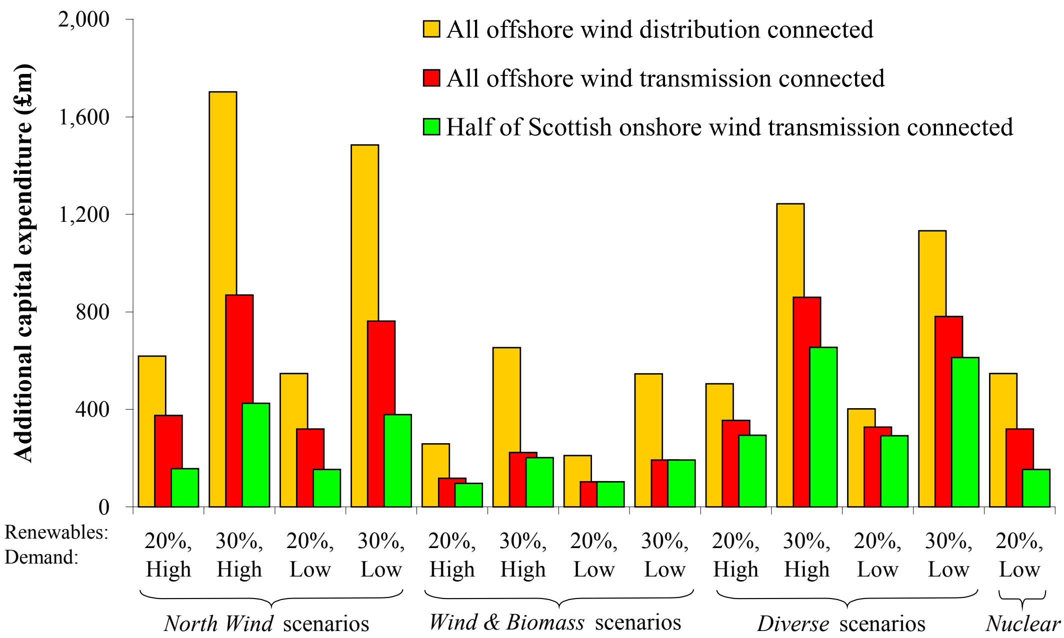
6.47 Figure 30 also shows the impact on total distribution capital expenditure of assuming that half of the onshore wind in Scotland connects directly to the transmission system rather than the distribution network. The distribution costs in this sensitivity assume the following to be distribution connected:

- all offshore wind in England and Wales;
- 50% of the onshore wind in Scotland; and
- no offshore wind.

6.48 As would be expected, the results show a significant reduction in distribution capital expenditure. Under this assumption, virtually all scenarios see some reduction in costs. There is no consequential increase, or change, to transmission costs under this sensitivity, as power flows on the transmission network would be unchanged and the transmission connection costs do not form part of the system costs considered in this study. However, there may be an increase in *project* costs paid by developers.

47 Offshore wind contributes in excess of 50% to the total distributed generation capacity in all three of these DNO areas – almost 70% in the case of South Wales.

Figure 30 – Alternative connection assumptions for offshore and onshore wind



6.49 Most notable, as one might expect, is the reduction in the total GB costs for the *North Wind* scenarios where onshore wind in Scotland accounts for the majority of renewable capacity. For these scenarios, total costs are approximately halved. Under the *North Wind* 30% (high) scenario, the North of Scotland has approximately 40% of the total onshore wind generation GB capacity. Furthermore, 95% of the North Scotland costs under this scenario are associated with new substations and circuit reinforcement costs. This is most probably a function of the longer feeding distances found on the North of Scotland network[48].

The effect of 'clustering' on distribution costs

6.50 Distributed generation may not be evenly spread throughout the available network but may form local concentrations of generation, known as *clustering*. These are likely to be the result of the local renewable resource availability but may also arise from local planning incentives – such as the development of renewable energy zones.

48 Under the modelling assumptions, longer feeding distances will increase circuit reinforcement costs. Also, the generation size assumptions for the *North Wind* scenarios mean that half of the total additional onshore wind capacity will comprise generation schemes requiring connection at 132kV. With 132kV circuit/reinforcement costs being disproportionately higher than costs at the other voltage levels, this will further increase total costs. Also, the longer feeding distances are likely to be the reason why fault level *headroom* is generally sufficient to accommodate the required level of generation without the need for significant replacement of circuit breaker switchboards.

6.51 The effect of clustering is to increase the generation deployment density over a defined proportion of each substation's 'capture area'. In high generation density areas, reinforcement costs increase significantly, and in the remaining low generation density areas, costs are reduced (when compared to the uniform deployment case).

6.52 Figure 31 shows the costs for clustered generation for each of the scenarios. When compared to the uniform deployment case, it can be seen that clustering increases costs in all scenarios by between 7% and 21%.

The effect of active voltage management

6.53 Active management of distribution networks has been shown to increase the amount of generation capacity which can be connected to distribution networks[49]. The extent to which the distribution network voltage is actively managed can range from *basic* to *advanced*.

'Basic' active voltage management

6.54 Under a basic system of active voltage management, distributed generators continue to operate independently but arrangements are put in place such that the power output from the generator is curtailed when required so as to ensure that local system voltages do not exceed desired limits.

6.55 This is a relatively low cost, rather unsophisticated, approach but does, nevertheless, increase the total amount of distributed generation which can be connected to the network. The study does not consider this arrangement.

'Advanced' active voltage management

6.56 Advanced management of system voltage involves the coordinated integration of the key voltage management devices on the distribution network[50]. Under a regime of advanced active network management, the aggregate generation capacity which can be connected to substations, before the system voltage exceeds acceptable limits, is significantly increased.

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49 Active management of distribution networks – a report by UMIST under the DTI's Renewable Energy Programme, 2002.

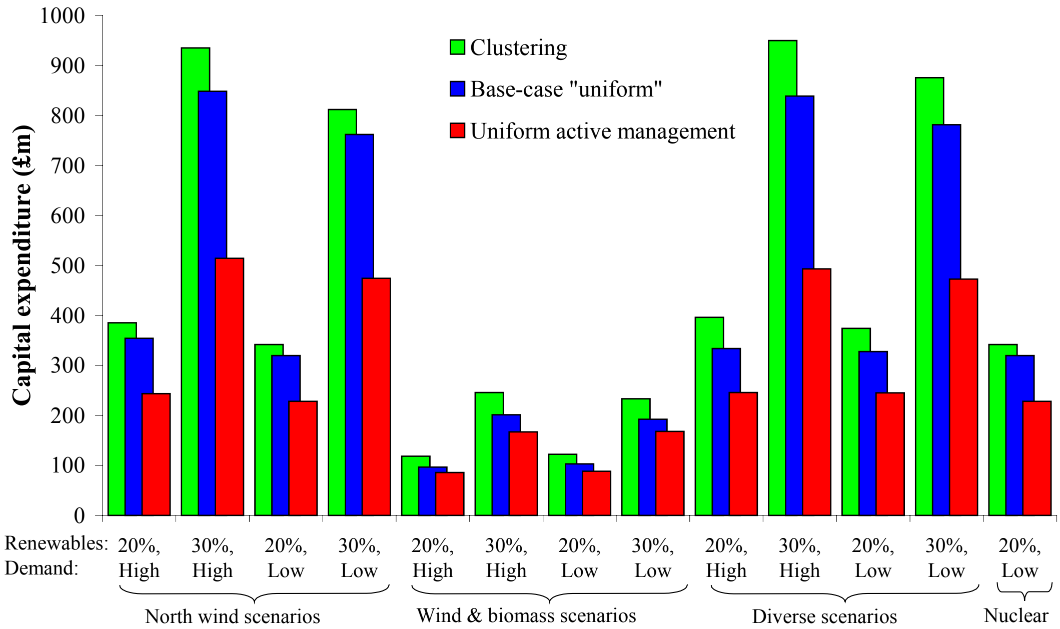
50 Advanced active voltage management involves the integrated coordination of transformer tap-changers, generator control devices and other network components which may be installed to assist in the management of network voltage. Voltage transformers (VTs) are installed on the network to enable the voltage to be measured at strategic locations. Information is collected from a number of sources and processed centrally, possibly on a zonal basis, such that system voltage can be optimally managed. Advanced management of this type may also require the installation of advanced SCADA systems. There are significant costs associated with establishing advanced, coordinated, voltage management systems of this sort. A fuller discussion on active voltage management is beyond the scope of this study.

6.57 This sensitivity study assumes that the total amount of generation that can be connected to each level of the distribution network is multiplied by a factor of 2.5 under a regime of advanced active voltage management.

6.58 In some instances, estimates of the costs associated with installing the necessary additional voltage management systems[51] exceeded the potential reinforcement savings. In such cases, active management was assumed not to have been implemented. Active management was only employed where a cost saving could be made.

6.59 Our results, illustrated in Figure 31, show that active voltage management can significantly reduce the total distribution reinforcement costs. Savings are most notable in the *Diverse* and *North Wind* 30% scenarios where the analysis shows cost reductions of around 40%.

Figure 31 – The effect of 'clustering' and active voltage management on distribution costs



The effect of generator size on distribution costs

6.60 Assumptions on the sizes of generators, per scenario for each generation technology type, have been made for the base case studies[52]. A further sensitivity

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51 Estimates of the costs associated with advanced active voltage management were obtained from manufacturers (via UMIST).

52 These assumptions are described in Annex F.

study was carried out assuming that the generation was deployed as a high number of small capacity schemes.

6.61 The analysis was carried out for the uniform, base case, 20% (High) and 30% (High) scenarios.

6.62 All onshore wind was assumed to comprise entirely 30MW schemes, all CHP schemes were 5MW, all other eligible renewable schemes 5MW. Biomass schemes under the *Diverse* scenarios were assumed to consist entirely of 1MW generators with all other biomass scenarios consisting of all 5MW projects.

6.63 The impact on total costs of meeting the 2020 targets through this low capacity, high scheme number route is shown in Figure 32.

6.64 It can be seen that a high population of small plant increases total costs significantly. This is particularly the case in the 30% W*ind & Biomass* scenario where total costs under this assumption increase fourfold.

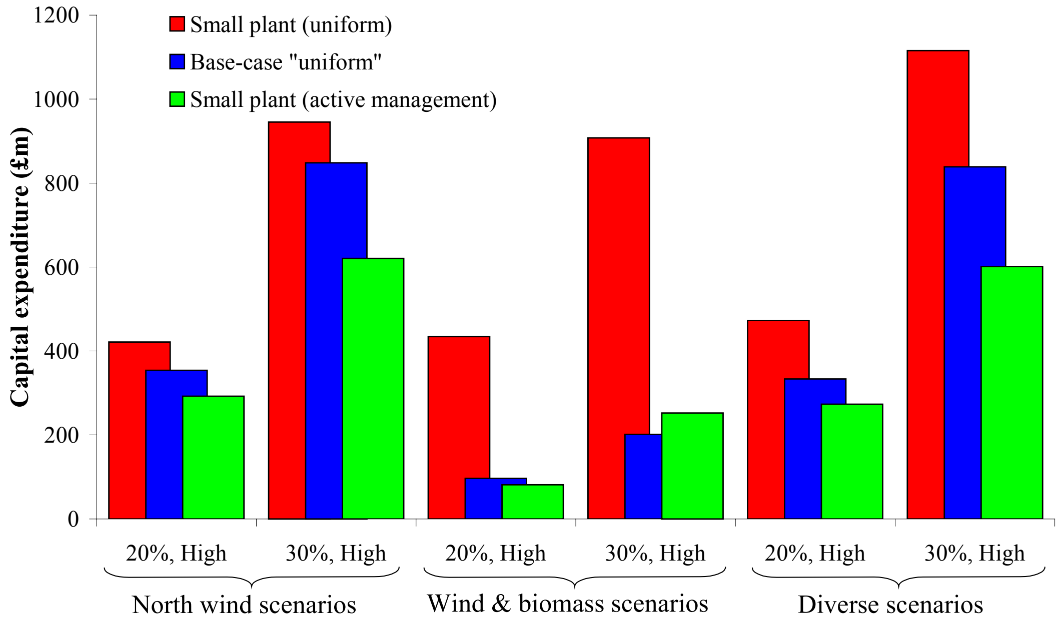
6.65 The chart also shows the potential effects of employing active voltage management systems. This can be seen to reduce the total cost significantly – almost down to the level of costs associated with the standard assumptions on plant size.

6.66 Under these 'small plant' assumptions, all generation except for onshore wind schemes are connected at the 11kV voltage level. The net effect is to hugely overload this lower voltage level giving rise to the need for a high number of new 33/11kV substations to be built.

6.67 In practice, this additional small plant may be connected to 33/11kV substations in much higher concentrations than permitted under the modelling assumptions in this study – together, possibly, with a smaller number of 132/33kV substations to feed the primary substations.

6.68 Hence, a more sophisticated modelling approach may lead to capital costs somewhat lower than those suggested by this sensitivity study. Nevertheless, a significant increase would still be expected as suggested by the analysis here.

Figure 32 – Effect of generator size on distribution costs



The effect on distribution costs of the availability of land area for renewable development

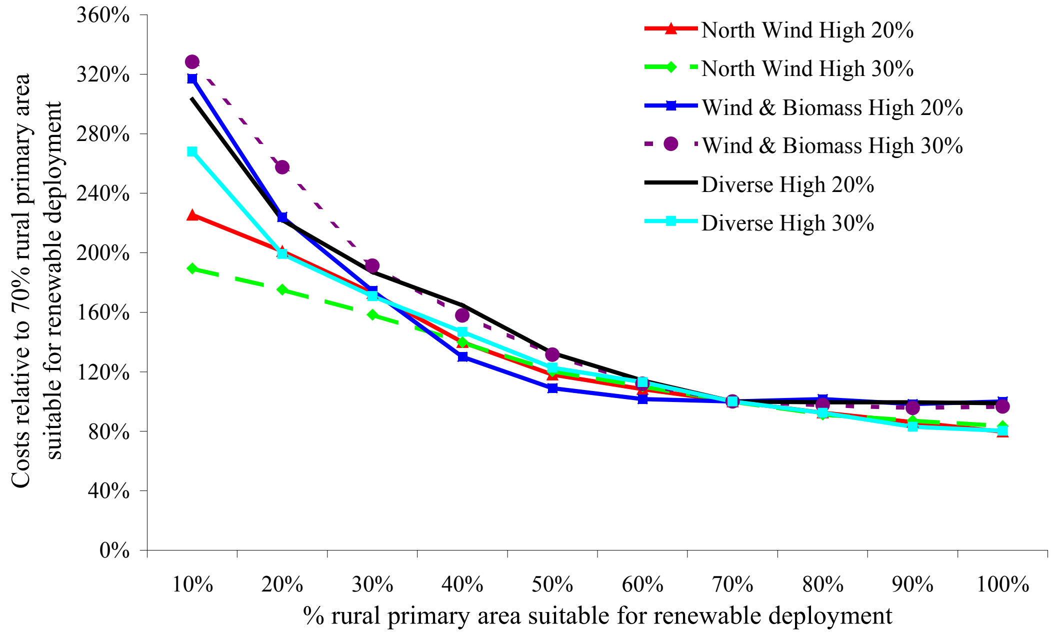
6.69 A final sensitivity study is to explore the impact on total costs of varying the proportion of the areas covered by each primary substation which is available for renewable development.

6.70 Figure 33 shows the change in total costs for the six high demand scenarios relative to the figure used in the base case of 70%.

6.71 As the amount of land area available for generation reduces, the generation density increases – driving up reinforcement costs – as is shown to occur in the high density zones under the clustering cases. The chart shows that the cost sensitivity reduces as the available land area increases – as shown by the general increased slope of the curve family at the lower land area percentages.

6.72 In general, the *Wind & Biomass* scenarios are shown to be most sensitive to available land area and the *North Wind* scenarios least sensitive.

Figure 33 – Impact of land area available for generator development



Key cost drivers

6.73 The results show that the costs of distribution system reinforcement associated with increased levels of renewable generation are driven by a number of key issues.

Increased levels of distributed generation

6.74 In all cases, the additional distribution system reinforcement costs increase with increased levels of generation deployment. The results show that the additional costs of achieving the 30% penetration levels when compared to achieving the 20% levels range from around 80% more to almost 150% more – depending on the scenario.

High generation deployment in a particular geographic location

6.75 The high penetrations of offshore wind generation in the North Wales and Eastern areas and the North of Scotland have a significant impact on the total reinforcement costs. Total costs increase significantly for all scenarios when the cost of accommodating offshore wind onto the local distribution network is included.

6.76 Similarly, a high density of onshore wind in the North of Scotland is shown to drive total costs up. Total GB costs are markedly reduced when half of the Scottish onshore wind generation is excluded.

Local concentrations of generation capacity

6.77 The effect of generation 'clustering' is shown to increase distribution costs. Although not a major cost driver, the additional costs associated with local concentrations of generation is notable and significant.

6.78 An increase in reinforcement costs of higher levels of generation density is also demonstrated by the impact of reducing the land area available for renewable deployment.

Circuit reinforcement at high voltages

6.79 At the higher distribution voltages, the cost of reinforcing existing circuits – new cabling and overhead line reinforcement – can be a large contributor to total distribution costs. The circuit reinforcement costs at 132kV can be particularly high. This tends to increase the relative cost of connecting a large number of generators in excess of 50MW – since it is assumed that these can not be accommodated at 11kV or 33kV where circuit reinforcement costs per MW are more modest.

6.80 Circuit costs may therefore be high in areas having significant amounts of wind generation – much of which is assumed to require a 132kV connection.

Absence of active voltage management

6.81 Active network management is shown to reduce reinforcement cost significantly – especially in geographic areas, or system voltage levels, which have high concentrations of generation.

Generation plant size

6.82 The analysis shows that a high population of small generation drives total costs up significantly. The high reinforcement costs associated with concentrations of larger generation schemes – such as wind turbines – suggests that a high number of similar sized plant increases costs.

6.83 High penetrations of similar sized generators tend to 'fill-up' system voltage levels quickly – giving rise to the need for reinforcement. Costs would seem to be lower where a diverse mix of generation sizes is deployed and the voltage levels can be populated with generation capacity more evenly – 'filling' all voltage levels before overloading any one voltage level.

6.84 These cost drivers are likely to feature significantly in any future assessment of the costs associated with connecting high penetrations of additional renewable generation to distribution networks.

7. DANISH EXPERIENCE

7.1 In Denmark, 20% of installed capacity and 12% of annual generation is from wind generation, whilst the bulk of power comes from CHP (78% of capacity and 88% of generation)[53]. Denmark is often held up as a benchmark for possible renewable development in the UK. Indeed, both countries have access to similar wind resources.

7.2 Danish wind development was boosted by government subsidies. A fixed-tariff system for renewables guaranteed income for new renewables until the end of 1999, when a change of government introduced plans for a replacement tradable green-certificate system. Implementation of the tradable system was repeatedly postponed and eventually shelved after objections from both the renewables industry and consumers. In order to revive several flagging offshore wind projects under development, the Danish government recently announced that it would continue to subsidise these projects at a lower level than previously. Operating renewables projects have had their tariffs grandfathered. The current regulatory uncertainty has put a halt to any further new developments.

7.3 Replacing despatched fossil-fuel plant with a large proportion of non-despatched intermittent generation in Denmark has also led to large system imbalances. The unpredictability of wind power requires an increase in the operational margins, and this, and its location, has required a strengthening of the transmission and distribution networks.

7.4 Alternative technologies to provide local balancing are under investigation and include, for example, the use of heat pumps to utilise surplus power from wind turbines, thereby reduce the heat-dependent electricity generation from CHP, or the use of more flexible electric heating via immersion boilers during periods of low demand/high generation. In the long term, alternatives such as hydrogen generation may offer additional flexibility.

7.5 In the meantime, the Danish system relies heavily on imports and exports of balancing power to maintain stability. The Danish interconnectors with Norway (1GW), Sweden (2.6GW) and Germany (2GW) have also become increasingly congested in recent years. In 2001, Denmark exported around 9.2TWh of electricity, and imported around 8.6TWh. Imports constituted almost a quarter of total system demand (35TWh).

7.6 Strengthening the interconnected Nordic transmission network is one of the likely prerequisites for further renewable deployment in those countries.

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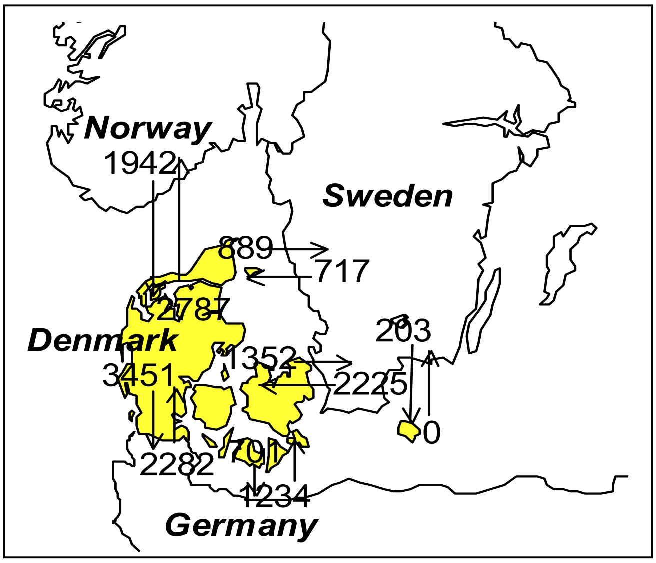
53 Generation and capacity values for 2001. Source: Nordel.

Lessons for Great Britain

7.7 The Danish experience may have few lessons for Great Britain. The two electricity systems may not be directly comparable and the 1999 change of policy on renewables came about principally due to a change of political ideology following a general election. The incoming government was keen to move away from the direct subsidies that the previous tariff regime had provided towards a market-based mechanism of tradable green certificates. The decision was not one related specifically to the extent of system costs arising from the large amount of wind generation.

Figure 34 – Danish imports and exports 2001 (GWh)



Source: Nordel

Comparing the Danish and GB electricity systems

7.8 Although Demark, like the UK, has a substantial wind resource relative to its electricity demand, there are significant differences between the systems. The Danish system is small. In 2001, power consumption in Denmark was around 35TWh for a population of 5.4 million. This is approximately 10% of the UK's 334TWh for 60 million inhabitants.

7.9 The Danish system is highly interconnected with 5.6GW of links to Germany, Norway and Sweden. This is an exceptionally high degree of interconnection for a country with a peak demand of 6GW and provides a valuable balancing tool. Net flows on these interconnectors are small, because substantial exports (9.2TWh in 2001), at times of low demand and/or high wind, are offset by high volumes of imports (8.6TWh in 2001) at other times. 60% of imports come from Norway and Sweden that have hydro-based systems that can respond at short notice to wind variation.

7.10 Great Britain by contrast, is essentially an islanded system, linked to the continental markets only through a 2GW link to France, for a system with a maximum demand of 59GW in 2001. This link is normally used to import power and only rarely provides a physical energy-balancing function. Both the Danish ands GB markets plan further interconnections, including a possible 1.3GW link between England and Norway. Even with planned increases in interconnection capacity, the UK will remain essentially an islanded system which constrains options for balancing via international imports or exports. As a consequence, the potential for renewable development in GB may be constrained by the requirement to maintain system stability internally.

7.11 We have not investigated in any detail the charging methods used to value the imports and exports on the Danish system, especially those that take place at relatively short notice. It may be the case that, if providing balancing and capacity services for the Danish system imposes additional costs on neighbouring systems, these costs will increasingly be passed on to Danish companies and consumers. It is not necessarily the case that imported balancing and capacity services are cheaper than domestic ones, although in the case of Denmark, this could be the case in view of the large hydro capacity of its neighbours.

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ANNEX A – CONTRIBUTORS

This work has been made possible through the valuable contributions of a large number of people who have given their time to assist our understanding of the issues described in this report and/or in the provision of information. Our thanks to all who contributed.

The views presented in this report do not necessarily represent the opinions of contributors or the organisations they represent.

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ANNEX B – FULL RESULTS

The following pages list the full results for each of the baselines and the renewable scenarios.

Technology and location scenario:		**Baseline**	**Baseline**	**Nuclear baseline**	***Nuclear***
Demand scenario:		High	Low	Low	Low
Renewables penetration scenario:		10%	10%	10%	20%
Scenario identifier:		A	B	C	R
Corresponding baseline:					C
Assumptions					
Annual demand	TWh	427	394	394	394
Generation					
Onshore wind	*TWh*	*17.9*	*15.7*	*15.7*	*35.4*
Offshore wind	*TWh*	*12.2*	*11.1*	*11.1*	*30.9*
Total wind	TWh	30.1	26.9	26.9	66.3
Biomass generation	TWh	2.9	2.9	2.9	2.9
Other contributing renewables	TWh	9.7	9.7	9.7	9.7
Total contributing renewables	TWh	42.7	39.4	39.4	78.9
Conventional plant	TWh	325.2	295.7	295.7	256.3
CHP / micro-CHP	TWh	57.5	57.5	57.5	57.5
Energy from waste	TWh	1.7	1.7	1.7	1.7
Peak demand	GW	75.7	69.9	69.9	69.9
Capacity					
Coal	*GW*	*12.1*	*12.1*	*12.1*	*12.1*
Nuclear	*GW*	*1.2*	*1.2*	*12.8*	*12.8*
Other conventional	*GW*	*60.7*	*54.2*	*44.6*	*43.1*
Total conventional	GW	74.0	67.5	69.5	68.0
Onshore wind	*GW*	*5.3*	*4.7*	*4.7*	*10.5*
Offshore wind	*GW*	*4.6*	*4.2*	*4.2*	*11.4*
Total wind	GW	9.9	8.9	8.9	21.9
Biomass generation	GW	0.5	0.5	0.5	0.5
Other renewables	GW	1.1	1.1	1.1	1.1
Total renewables	GW	12.8	11.8	11.8	24.8
CHP / micro-CHP	GW	12.0	12.0	12.0	12.0
Total capacity	GW	98.8	91.3	93.3	104.8
Results					
Total capital costs					
Balancing	£m	30	30	30	60
Transmission	£m	1,285	1,275	1,275	2,784
Distribution	£m	21	-	-	320
Total	£m	1,336	1,305	1,305	3,164
Total annual costs					
Balancing					
Response	£m	74	73	73	85
Synchronized reserve	£m	30	30	30	69
Standing reserve	£m	14	13	13	24
Start-up	£m	18	18	18	31
Wind curtailment	£m	-	-	0	6
Capacity	£m	28	31	6	199
Transmission losses	£m	131	116	134	152
Total		294	281	274	567
Additional costs (Annualised capital costs + annual costs)					
Balancing	£m	-	-	-	82
Capacity	£m	-	-	-	194
Transmission	£m	-	-	-	124
Distribution	£m	-	-	-	21
Total	£m	-	-	-	420

Technology and location scenario:		***North Wind***	***North Wind***	***North Wind***	***North Wind***
Demand scenario:		High	High	Low	Low
Renewables penetration scenario:		20%	30%	20%	30%
Scenario identifier:		D	E	F	G
Corresponding baseline:		A	A	B	B
Assumptions					
Annual demand	TWh	427	427	394	394
Generation					
Onshore wind	*TWh*	*39.3*	*60.6*	*35.4*	*55.2*
Offshore wind	*TWh*	*33.6*	*54.9*	*30.9*	*50.6*
Total wind	TWh	72.8	115.6	66.3	105.7
Biomass generation	TWh	2.9	2.9	2.9	2.9
Other contributing renewables	TWh	9.7	9.7	9.7	9.7
Total contributing renewables	TWh	85.4	128.1	78.9	118.3
Conventional plant	TWh	282.5	239.8	256.3	216.9
CHP / micro-CHP	TWh	57.5	57.5	57.5	57.5
Energy from waste	TWh	1.7	1.7	1.7	1.7
Peak demand	GW	75.7	75.7	69.9	69.9
Capacity					
Coal	*GW*	*12.1*	*12.1*	*12.1*	*12.1*
Nuclear	*GW*	*1.2*	*1.2*	*1.2*	*1.2*
Other conventional	*GW*	*58.7*	*57.2*	*52.2*	*50.7*
Total conventional	GW	72.0	70.5	65.5	64.0
Onshore wind	*GW*	*11.6*	*17.8*	*10.5*	*16.2*
Offshore wind	*GW*	*12.4*	*20.2*	*11.4*	*18.6*
Total wind	GW	24.0	38.0	21.9	34.8
Biomass generation	GW	0.5	0.5	0.5	0.5
Other renewables	GW	1.1	1.1	1.1	1.1
Total renewables	GW	26.9	40.9	24.8	37.8
CHP / micro-CHP	GW	12.0	12.0	12.0	12.0
Total capacity	GW	110.9	123.4	102.3	113.8
Results					
Total capital costs					
Balancing	£m	60	60	60	60
Transmission	£m	2,362	4,310	2,341	4,278
Distribution	£m	376	870	320	762
Total	£m	2,797	5,239	2,720	5,100
Total annual costs					
Balancing					
Response	£m	88	105	85	101
Synchronized reserve	£m	79	145	70	134
Standing reserve	£m	27	40	25	37
Start-up	£m	35	51	31	47
Wind curtailment	£m	0	11	0	11
Capacity	£m	219	435	199	393
Transmission losses	£m	178	139	161	117
Total		625	926	572	840
Additional costs (Annualised capital costs + annual costs)					
Balancing	£m	93	217	77	196
Capacity	£m	191	407	168	362
Transmission	£m	91	242	92	239
Distribution	£m	23	55	21	49
Total	£m	398	921	358	846

Technology and location scenario:		***Wind & Biomass***	***Wind & Biomass***	***Wind & Biomass***	***Wind & Biomass***
Demand scenario:		High	High	Low	Low
Renewables penetration scenario:		20%	30%	20%	30%
Scenario identifier:		H	I	J	K
Corresponding baseline:		A	A	B	B
Assumptions					
Annual demand	TWh	427	427	394	394
Generation					
Onshore wind	*TWh*	*39.3*	*60.6*	*35.4*	*55.2*
Offshore wind	*TWh*	*12.2*	*12.2*	*11.1*	*11.1*
Total wind	TWh	51.5	72.8	46.6	66.3
Biomass generation	TWh	24.3	45.6	22.6	42.3
Other contributing renewables	TWh	9.7	9.7	9.7	9.7
Total contributing renewables	TWh	85.4	128.1	78.9	118.3
Conventional plant	TWh	282.5	239.8	256.3	216.9
CHP / micro-CHP	TWh	57.5	57.5	57.5	57.5
Energy from waste	TWh	1.7	1.7	1.7	1.7
Peak demand	GW	75.7	75.7	69.9	69.9
Capacity					
Coal	*GW*	*12.1*	*12.1*	*12.1*	*12.1*
Nuclear	*GW*	*1.2*	*1.2*	*1.2*	*1.2*
Other conventional	*GW*	*56.7*	*53.2*	*50.7*	*46.7*
Total conventional	GW	70.0	66.5	64.0	60.0
Onshore wind	*GW*	*11.6*	*17.8*	*10.5*	*16.2*
Offshore wind	*GW*	*4.6*	*4.6*	*4.2*	*4.2*
Total wind	GW	16.2	22.4	14.6	20.4
Biomass generation	GW	4.2	7.9	3.9	7.3
Other renewables	GW	1.1	1.1	1.1	1.1
Total renewables	GW	22.8	32.7	21.0	30.2
CHP / micro-CHP	GW	12.0	12.0	12.0	12.0
Total capacity	GW	104.8	111.2	97.0	102.2
Results					
Total capital costs					
Balancing	£m	60	60	60	60
Transmission	£m	1,393	1,508	1,375	1,482
Distribution	£m	118	223	103	192
Total	£m	1,571	1,791	1,538	1,735
Total annual costs					
Balancing					
Response	£m	81	87	79	85
Synchronized reserve	£m	57	93	53	87
Standing reserve	£m	19	26	18	24
Start-up	£m	26	33	24	31
Wind curtailment	£m	-	0	-	0
Capacity	£m	123	244	115	199
Transmission losses	£m	108	106	100	139
Total		414	588	389	565
Additional costs (Annualised capital costs + annual costs)					
Balancing	£m	47	103	40	93
Capacity	£m	95	216	84	168
Transmission	£m	-6	-8	-4	-3
Distribution	£m	6	13	7	12
Total	£m	143	325	127	271

Technology and location scenario:		***Diverse***	***Diverse***	***Diverse***	***Diverse***
Demand scenario:		High	High	Low	Low
Renewables penetration scenario:		20%	30%	20%	30%
Scenario identifier:		L	M	N	O
Corresponding baseline:		A	A	B	B
Assumptions					
Annual demand	TWh	427	427	394	394
Generation					
Onshore wind	*TWh*	*30.7*	*43.5*	*27.6*	*39.4*
Offshore wind	*TWh*	*33.6*	*54.9*	*30.9*	*50.6*
Total wind	TWh	64.3	98.5	58.4	90.0
Biomass generation	TWh	11.4	20.0	10.8	18.7
Other contributing renewables	TWh	9.7	9.7	9.7	9.7
Total contributing renewables	TWh	85.4	128.1	78.9	118.3
Conventional plant	TWh	282.5	239.8	256.3	216.9
CHP / micro-CHP	TWh	57.5	57.5	57.5	57.5
Energy from waste	TWh	1.7	1.7	1.7	1.7
Peak demand	GW	75.7	75.7	69.9	69.9
Capacity					
Coal	*GW*	*12.1*	*12.1*	*12.1*	*12.1*
Nuclear	*GW*	*1.2*	*1.2*	*1.2*	*1.2*
Other conventional	*GW*	*58.2*	*55.7*	*51.7*	*49.2*
Total conventional	GW	71.5	69.0	65.0	62.5
Onshore wind	*GW*	*9.1*	*12.8*	*8.2*	*11.6*
Offshore wind	*GW*	*12.4*	*20.2*	*11.4*	*18.6*
Total wind	GW	21.5	33.0	19.6	30.2
Biomass generation	GW	2.0	3.5	1.9	3.2
Other renewables	GW	1.1	1.1	1.1	1.1
Total renewables	GW	25.9	38.9	23.8	35.9
CHP / micro-CHP	GW	12.0	12.0	12.0	12.0
Total capacity	GW	109.4	119.9	100.8	110.4
Results					
Total capital costs					
Balancing	£m	60	60	60	60
Transmission	£m	1,643	2,584	1,623	2,554
Distribution	£m	355	860	328	782
Total	£m	2,058	3,505	2,011	3,396
Total annual costs					
Balancing					
Response	£m	85	98	83	94
Synchronized reserve	£m	70	124	66	114
Standing reserve	£m	24	35	22	32
Start-up	£m	31	44	29	40
Wind curtailment	£m	-	4	-	4
Capacity	£m	186	343	145	311
Transmission losses	£m	150	125	140	161
Total		545	774	485	756
Additional costs (Annualised capital costs + annual costs)					
Balancing	£m	75	170	66	150
Capacity	£m	158	315	114	280
Transmission	£m	31	103	32	106
Distribution	£m	22	54	21	50
Total	£m	285	642	233	587

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ANNEX C – ASSUMED LOCATION FOR ADDITIONAL RENEWABLE CAPACITY (MW) BY TECHNOLOGY

GSP Group	Technology and location	Baseline	Baseline	Nuclear baseline	*Nuclear*	*North Wind*	*North Wind*	*North Wind*	*North Wind*
	Demand	High	Low	Low	Low	High	High	Low	Low
	Penetration	10%	10%	10%	20%	20%	30%	20%	30%
	Scenario ID	A	B	C	R	D	E	F	G
Eastern	Offshore wind	1,336	1,176	1,176	3,196	3,524	5,712	3,196	5,217
Eastern	Onshore wind	450	394	394	394	450	450	394	394
Eastern	Other renewables	106	106	106	106	106	106	106	106
Eastern	Other embedded	892	892	892	892	892	892	892	892
Eastern	Total	2,784	2,568	2,568	4,588	4,972	7,160	4,588	6,608
East Midlands	Offshore wind	360	317	317	317	360	360	317	317
East Midlands	Onshore wind	72	61	61	61	72	72	61	61
East Midlands	Other renewables	163	163	163	163	163	163	163	163
East Midlands	Other embedded	367	367	367	367	367	367	367	367
East Midlands	Total	962	908	908	908	962	962	908	908
London	Offshore wind	-	-	-	-	-	-	-	-
London	Onshore wind	8	7	7	7	8	8	7	7
London	Other renewables	99	99	99	99	99	99	99	99
London	Other embedded	399	399	399	399	399	399	399	399
London	Total	506	505	505	505	506	506	505	505
Midlands	Offshore wind	-	-	-	-	-	-	-	-
Midlands	Onshore wind	314	270	270	270	314	314	270	270
Midlands	Other renewables	261	261	261	261	261	261	261	261
Midlands	Other embedded	619	619	619	619	619	619	619	619
Midlands	Total	1,194	1,150	1,150	1,150	1,194	1,194	1,150	1,150
Northern	Offshore wind	11	10	10	10	11	11	10	10
Northern	Onshore wind	270	230	230	951	1,052	1,833	951	1,673
Northern	Other renewables	68	68	68	68	68	68	68	68
Northern	Other embedded	693	693	693	693	693	693	693	693
Northern	Total	1,042	1,000	1,000	1,722	1,823	2,605	1,722	2,443
North West	Offshore wind	616	542	542	1,119	1,241	1,866	1,119	1,696
North West	Onshore wind	149	128	128	849	931	1,712	849	1,571
North West	Other renewables	216	216	216	216	216	216	216	216
North West	Other embedded	861	861	861	861	861	861	861	861
North West	Total	1,842	1,746	1,746	3,045	3,248	4,655	3,045	4,344
North Wales	Offshore wind	810	713	713	1,868	2,061	3,311	1,868	3,022
North Wales	Onshore wind	188	163	163	884	969	1,751	884	1,606
North Wales	Other renewables	81	81	81	81	81	81	81	81
North Wales	Other embedded	1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406
North Wales	Total	2,486	2,364	2,364	4,240	4,518	6,549	4,240	6,116
South East	Offshore wind	330	290	290	290	330	330	290	290
South East	Onshore wind	43	38	38	38	43	43	38	38
South East	Other renewables	145	145	145	145	145	145	145	145
South East	Other embedded	850	850	850	850	850	850	850	850
South East	Total	1,367	1,323	1,323	1,323	1,367	1,367	1,323	1,323
Southern	Offshore wind	330	290	290	290	330	330	290	290
Southern	Onshore wind	43	38	38	38	43	43	38	38
Southern	Other renewables	145	145	145	145	145	145	145	145
Southern	Other embedded	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144
Southern	Total	1,661	1,617	1,617	1,617	1,661	1,661	1,617	1,617
South Wales	Offshore wind	810	713	713	713	810	810	713	713
South Wales	Onshore wind	188	163	163	163	188	188	163	163
South Wales	Other renewables	81	81	81	81	81	81	81	81
South Wales	Other embedded	588	588	588	588	588	588	588	588
South Wales	Total	1,668	1,545	1,545	1,545	1,668	1,668	1,545	1,545

GSP Group	**Technology and location** Demand Penetration	**Baseline** High 10%	**Baseline** Low 10%	**Nuclear baseline** Low 10%	***Nuclear*** Low 20%	***North Wind*** High 20%	***North Wind*** High 30%	***North Wind*** Low 20%	***North Wind*** Low 30%
South West	Offshore wind	166	146	146	146	166	166	146	146
South West	Onshore wind	174	151	151	151	174	174	151	151
South West	Other renewables	152	152	152	152	152	152	152	152
South West	Other embedded	472	472	472	472	472	472	472	472
South West	Total	964	921	921	921	964	964	921	921
Yorkshire	Offshore wind	576	507	507	1,084	1,201	1,826	1,084	1,662
Yorkshire	Onshore wind	206	180	180	901	988	1,769	901	1,623
Yorkshire	Other renewables	177	177	177	177	177	177	177	177
Yorkshire	Other embedded	1,543	1,543	1,543	1,543	1,543	1,543	1,543	1,543
Yorkshire	Total	2,503	2,407	2,407	3,706	3,909	5,315	3,706	5,004
Northern Scotland	Offshore wind	-	-	-	1,154	1,250	2,500	1,154	2,309
Northern Scotland	Onshore wind	1,549	1,466	1,466	4,352	4,674	7,799	4,352	7,238
Northern Scotland	Other renewables	36	36	36	36	36	36	36	36
Northern Scotland	Other embedded	357	357	357	357	357	357	357	357
Northern Scotland	Total	1,941	1,858	1,858	5,899	6,316	10,692	5,899	9,939
Southern Scotland	Offshore wind	-	-	-	289	313	625	289	577
Southern Scotland	Onshore wind	910	882	882	2,325	2,472	4,035	2,325	3,768
Southern Scotland	Other renewables	36	36	36	36	36	36	36	36
Southern Scotland	Other embedded	315	315	315	315	315	315	315	315
Southern Scotland	Total	1,260	1,232	1,232	2,964	3,135	5,010	2,964	4,696

GSP Group	Technology and location Demand Penetration Scenario ID	*Wind & Biomass* High 20% H	*Wind & Biomass* High 30% I	*Wind & Biomass* Low 20% J	*Wind & Biomass* Low 30% K	*Diverse* High 20% L	*Diverse* High 30% M	*Diverse* Low 20% N	*Diverse* Low 30% O
Eastern	Offshore wind	2,899	4,462	2,619	4,062	2,274	3,212	2,042	2,908
Eastern	Onshore wind	450	450	394	394	1,563	2,676	1,422	2,449
Eastern	Other renewables	503	901	473	840	265	424	253	400
Eastern	Other embedded	892	892	892	892	892	892	892	892
Eastern	Total	4,745	6,705	4,378	6,188	4,994	7,204	4,608	6,649
East Midlands	Offshore wind	781	1,203	706	1,095	613	866	550	784
East Midlands	Onshore wind	72	72	61	61	280	488	253	445
East Midlands	Other renewables	451	738	429	694	278	393	269	375
East Midlands	Other embedded	367	367	367	367	367	367	367	367
East Midlands	Total	1,671	2,380	1,563	2,217	1,538	2,114	1,440	1,972
London	Offshore wind	-	-	-	-	-	-	-	-
London	Onshore wind	8	8	7	7	22	36	20	33
London	Other renewables	145	192	142	185	118	136	116	133
London	Other embedded	399	399	399	399	399	399	399	399
London	Total	552	599	548	591	538	571	535	565
Midlands	Offshore wind	-	-	-	-	-	-	-	-
Midlands	Onshore wind	314	314	270	270	1,195	2,076	1,083	1,897
Midlands	Other renewables	337	413	331	401	291	321	289	317
Midlands	Other embedded	619	619	619	619	619	619	619	619
Midlands	Total	1,270	1,346	1,220	1,290	2,105	3,017	1,991	2,833
Northern	Offshore wind	23	36	21	33	18	26	17	24
Northern	Onshore wind	270	270	230	230	1,075	1,880	973	1,716
Northern	Other renewables	326	584	306	545	171	275	164	259
Northern	Other embedded	693	693	693	693	693	693	693	693
Northern	Total	1,313	1,583	1,250	1,500	1,958	2,874	1,846	2,692
North West	Offshore wind	1,336	2,056	1,207	1,872	1,048	1,480	941	1,340
North West	Onshore wind	149	149	128	128	576	1,002	522	916
North West	Other renewables	660	1,104	626	1,036	394	571	380	544
North West	Other embedded	861	861	861	861	861	861	861	861
North West	Total	3,006	4,170	2,821	3,897	2,878	3,915	2,703	3,660
North Wales	Offshore wind	1,758	2,706	1,588	2,464	1,379	1,948	1,238	1,763
North Wales	Onshore wind	188	188	163	163	681	1,174	618	1,073
North Wales	Other renewables	272	462	257	433	158	234	152	222
North Wales	Other embedded	1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406
North Wales	Total	3,624	4,762	3,415	4,466	3,624	4,761	3,415	4,465
South East	Offshore wind	715	1,100	646	1,002	330	330	290	290
South East	Onshore wind	43	43	38	38	142	241	129	220
South East	Other renewables	358	572	342	539	230	316	224	303
South East	Other embedded	850	850	850	850	850	850	850	850
South East	Total	1,966	2,565	1,876	2,429	1,552	1,736	1,493	1,663
Southern	Offshore wind	715	1,100	646	1,002	330	330	290	290
Southern	Onshore wind	43	43	38	38	142	241	129	220
Southern	Other renewables	358	572	342	539	230	316	224	303
Southern	Other embedded	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144
Southern	Total	2,260	2,859	2,170	2,723	1,846	2,030	1,787	1,957
South Wales	Offshore wind	1,758	2,706	1,588	2,464	1,379	1,948	1,238	1,763
South Wales	Onshore wind	188	188	163	163	681	1,174	618	1,073
South Wales	Other renewables	272	462	257	433	158	234	152	222
South Wales	Other embedded	588	588	588	588	588	588	588	588
South Wales	Total	2,806	3,944	2,596	3,647	2,805	3,943	2,596	3,646

GSP Group	**Technology and location**	***Wind & Biomass***	***Wind & Biomass***	***Wind & Biomass***	***Wind & Biomass***	***Diverse***	***Diverse***	***Diverse***	***Diverse***
	Demand	High	High	Low	Low	High	High	Low	Low
	Penetration	20%	30%	20%	30%	20%	30%	20%	30%
South West	Offshore wind	359	553	325	504	166	166	146	146
South West	Onshore wind	174	174	151	151	644	1,114	584	1,018
South West	Other renewables	748	1,345	703	1,253	390	629	372	592
South West	Other embedded	472	472	472	472	472	472	472	472
South West	Total	1,754	2,544	1,650	2,380	1,672	2,380	1,575	2,228
Yorkshire	Offshore wind	1,250	1,924	1,130	1,752	981	1,385	881	1,254
Yorkshire	Onshore wind	206	206	180	180	731	1,256	664	1,149
Yorkshire	Other renewables	926	1,674	868	1,559	476	776	453	730
Yorkshire	Other embedded	1,543	1,543	1,543	1,543	1,543	1,543	1,543	1,543
Yorkshire	Total	3,925	5,348	3,721	5,034	3,731	4,960	3,541	4,676
Northern Scotland	Offshore wind	-	-	-	-	413	825	381	762
Northern Scotland	Onshore wind	1,549	1,549	1,466	1,466	3,190	4,831	2,981	4,497
Northern Scotland	Other renewables	57	78	55	75	44	52	43	51
Northern Scotland	Other embedded	357	357	357	357	357	357	357	357
Northern Scotland	Total	1,962	1,983	1,878	1,897	4,003	6,065	3,762	5,667
Southern Scotland	Offshore wind	-	-	-	-	166	332	153	307
Southern Scotland	Onshore wind	910	910	882	882	1,457	2,004	1,387	1,892
Southern Scotland	Other renewables	57	78	55	75	44	52	43	51
Southern Scotland	Other embedded	315	315	315	315	315	315	315	315
Southern Scotland	Total	1,281	1,302	1,252	1,271	1,982	2,703	1,899	2,565

ANNEX D – WORKED EXAMPLE OF CAPACITY COST CALCULATIONS

This annex and Table 18 describes the methodology adopted for calculating capacity costs within the study.

Background

There are a number of ways in which the cost of the additional capacity can be calculated. The most comprehensive manner would be to calculate the total capacity and energy costs of the electrical system as a whole. However, this route would not enable us to segregate the capacity costs from the costs of establishing renewables, and so would not meet the remit of the study. We have therefore adopted a somewhat more simplistic approach, but one we believe produces robust results.

Methodology

Firstly, we have calculated the annual wind generation in each scenario and determined the equivalent amount of conventional capacity required to produce the same generation, assuming a CCGT operating at 85% load factor. For example:

(i) The 9.9GW of wind capacity assumed in the high demand baseline (A) produces 30TWh of electricity per annum. 4GW of CCGT produces the same annual generation.

(ii) The 24GW of wind capacity assumed in the 20% *North Wind* high demand scenario (D) produces 73TWh of electricity per annum. 9.8GW of CCGT produces the same annual generation.

However, conventional capacity can be viewed as delivering two services, energy production and capacity. If we firstly consider that wind can provide no contribution to capacity margin, then to be equivalent to the conventional generation, wind would require back-up from generation equal to the equivalent conventional capacity. This capacity could come from a number of sources, including old conventional generation or new open cycle gas turbines (OCGTs). We have costed the capacity requirement at the price of a new, but not leading-edge, OCGT (£47/kW/pa), suitable for peaking operation, as we consider that at the margin, only OCGTs will be used, as any economically feasible existing generation would already be utilised on the system. Thus:

(i) Cost of 4GW of OCGT peaking capacity at £47/kW/pa, is £190m per annum.

(ii) Cost of 9.8GW of OCGT peaking capacity at £47/kW/pa, is £460m per annum.

The additional cost of North Wind scenario with no capacity contribution from wind is £460m – £190m = £270m

If we believe that wind does contribute to system security, albeit at a lower rate than conventional capacity, then the above capacity requirement is reduced by the level of that contribution:

(i) We have calculated that the 9.9GW of wind in the high demand baseline contributes 3.5GW of capacity to the system. The additional capacity requirement is reduced by this amount and now becomes 4.0GW – 3.5GW = 0.5GW. At £47/kW/pa the capacity cost of baseline A is now £26m per annum.

(ii) We have calculated that the 24GW of wind in the 20% *North Wind* scenario contributes 5.5GW of capacity to the system. The additional capacity requirement is reduced by this amount and now becomes 9.8GW – 5.5GW = 4.3GW. At £47/kW/pa the capacity cost of scenario D is now £201m per annum.

The additional cost of North Wind scenario with a capacity contribution from wind is therefore £201m – £26m = £175m

However, the above calculations assume that wind generation is directly equivalent to that from a CCGT. This will not be the case. Wind generation tends to have an energy value approximately equivalent to the time-weighted average (TWA) price whereas, generation from a more controllable CCGT (operating at 85% load factor, as assumed above) would have a value some 4% above TWA. If we assume that the energy component of wholesale prices (sufficient to cover marginal costs) in 2020 is £13.75/MWh, then the wind generation would be worth some £0.55/MWh less than that from the equivalent CCGT. The above capacity costs should take account of this.

(i) Wind generation in Baseline A is 30TWh, on which the energy adjustment would be 30 x 0.55 = £16m per annum. Where wind contributes to capacity, only 12.5% (0.5GW / 4.0GW) of this generation is deemed to come from a CCGT, so the energy adjustment is reduced to £2m per annum.

(ii) Wind generation in Scenario D is 73TWh, on which the energy adjustment would be 73 x 0.55 = £40m per annum. Where wind contributes to capacity, 56% (5.5GW / 9.8GW) of this generation is deemed to come from a CCGT, so the energy adjustment is reduced to £17m per annum.

Where wind does not contribute to capacity, the additional system security costs of wind generation are thus increased by £24m (£40m – £16m) to £293m.

Where wind does contribute to capacity, the additional system security costs of wind generation are thus increased by £15m (£17m – £2m) to £191m.

Table 18 – Worked example of capacity cost calculations

Technology and location scenario		Baseline	*North Wind*
Demand		High	High
Penetration		10%	20%
Scenario identifier		A	D
Wind generation	MWh	30,133,391	72,843,391
Wind capacity	MW	9,909	23,973
No capacity contribution from wind			
CCGT load factor	%	85%	85%
Thermal capacity equivalent	MW	4,047	9,783
Wind capacity contribution	MW	-	-
Required thermal capacity	MW	4,047	9,783
Capacity cost	£/kW/pa	47	47
Capacity cost	£m/pa	190	460
Energy correction charge	£/MWh	0.55	0.55
Annual correction cost	£m	16.42	39.70
Total cost	£m	206.63	499.50
Additional cost	£m		292.87
Capacity contribution from wind			
Thermal capacity required without wind	MW	77,500	77,500
Thermal capacity required with wind	MW	74,000	72,000
Wind capacity contribution	MW	3,500	5,500
CCGT load factor		85%	85%
Thermal capacity equivalent	MW	4,047	9,783
Wind capacity contribution	MW	3,500	5,500
Required thermal capacity	MW	547	4,283
Capacity cost	£/kW/pa	47	47
Capacity cost	£m/pa	26	201
Energy correction charge	£/MWh	0.55	0.55
Annual correction cost	£m	2.22	17.38
Total cost	£m	27.92	218.68
Additional cost	£m		190.75

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ANNEX E – TRANSMISSION CIRCUIT REINFORCEMENTS

Baselines ***Capex: £1,275m – £1,285m***

- Upgrade to 400 kV Beauly to Bonnybridge
- Reconduct 275 kV Cruchan to Windyhill
- Upgrade to 400 kV east coast circuit from Beauly to Longannet
- Reconduct 275 kV Kintore via Longannet to Cockenzie
- Reconduct 275 kV Longannet to Clydes Mill
- Reconduct 275 kV Mersey Ring
- Reconduct 400 kV Deeside to Daines

North Wind 20% ***Capex: £2,341m – £2,362m***

- Upgrade double circuit to 400 kV Beauly to Bonnybridge
- Upgrade double circuit to 400 kV east coast circuit from Beauly to Cockenzie
- Reconduct 275 kV Cruchan to Windyhill
- Upgrade to 400 kV all circuits Longannet to Strathaven
- Reconduct 275 kV Wisham to Smeaton
- Reconduct 275 kV Kintore to Longannet
- Reconduct 400 kV Windyhill to Inverkip
- Upgrade to 400 kV double circuit Windyhill to Longannet
- Reconduct 400 kV west and east coast interconnectors
- Reconduct 275 kV double circuits Harker to Blyth Harbour
- Upgrade to 400 kV east part of northeast network
- Reconduct 400 kV north west circuits (Harker to Penwortham, including the ring)
- Upgrade to 400 kV Mersey Ring
- Reconduct 275 kV Carrington to Macclesfield
- Reconduct 400 kV Daines to Carrington
- Reconduct 400 kV Deeside to Daines
- New circuit 400 kV Daines to Cellarhead
- New circuit 400 kV from Legacy to Ironbridge
- Upgrade to 400 kV Brinsworth to High Marnham
- Reconduct 400 kV Penwortham to Heysham

North Wind 30% ***Capex: £4,278m – £4,310m***

- Upgrade double circuits to 400 kV Beauly to Bonnybridge
- Upgrade four east coast circuits to 400 kV Beauly to Longannet
- Reconduct 275 kV Cruchan to Windyhill
- Upgrade to 400 kV Kincardine to Cockenzie
- Upgrade to 400 kV all circuits Longannet to Strathaven
- Upgrade to 400 kV Strathaven to Smeaton
- Upgrade to 400 kV Strathaven to Neilston
- Reconduct 400 kV Strathaven to Harker
- Reconduct 400 kV Windyhill to Inverkip
- Upgrade to 400 kV double circuit Windyhill to Longannet
- New 400 kV circuits Eccles to Harker
- New 400 kV circuits west coast Kilmarnock South via Harker to Heysham
- Reconduct 400 kV west and east coast interconnectors
- Upgrade to 400 kV double circuits Harker to Blyth Harbour
- Upgrade to 400 kV north east network
- Reconduct 400 kV north west circuits (Harker to Penwortham, including the ring)
- Reconduct 400 kV Penwortham to Daines
- Upgrade to 400 kV Mersey Ring
- Upgrade to 400 kV Carrington to Macclesfield
- Reconduct 400 kV Daines to Carrington
- Reconduct 400 kV Deeside to Daines
- New circuit 400 kV from Legacy to Penn
- Upgrade to 400 kV Brinsworth to High Marnham
- Reconduct 400 kV Penwortham to Heysham
- New circuit 400 kV Daines to Cellarhead
- Reconduct 400 kV south west circuits (Ironbridge via Feckenham to Walham and Minety)
- Reconduct 400 kV Ratcliffe to Willington East
- Reconduct 400 kV circuits Rayleigh Main to Grain

Wind & Biomass 20% ***Capex: £1,375m – £1,393m***

- Upgrade double circuit to 400 kV Beauly to Bonnybridge
- Reconduct 275 kV Cruchan to Windyhill
- Upgrade to 400 kV east coast circuit from Beauly to Kincardine
- Reconduct 275 kV Kintore to Longannet
- Reconduct 275 kV Longannet to Cockenzie
- Reconduct 275 kV Longannet to Clydes Mill
- Reconduct 400 kV Daines to Carrington
- Reconduct 400 kV Deeside to Daines
- Reconduct 400 kV Legacy to Penn
- Reconduct 275 kV Mersey Ring

Wind & Biomass 30% ***Capex: £1,482m – £1,508m***

- Upgrade double circuit to 400 kV Beauly to Bonnybridge
- Reconduct 275 kV Cruchan to Windyhill
- Upgrade to 400 kV east coast circuit from Beauly to Kincardine
- Reconduct 275 kV Kintore to Longannet
- Reconduct 275 kV Longannet to Cockenzie
- Reconduct 275 kV Longannet to Clydes Mill
- Reconduct 400 kV Daines to Carrington
- Reconduct 400 kV Deeside to Daines
- Reconduct 400 kV Legacy to Penn
- Upgrade to 400 kV Mersey Ring

Diverse 20% ***Capex: £1,623m – £1,643m***

- Upgrade double circuit to 400 kV Beauly to Bonnybridge
- Upgrade double circuit to 400 kV east coast circuit from Beauly to Cockenzie
- Reconduct 275 kV Cruchan to Windyhill
- Reconduct 275 kV Kintore via Longannet
- Reconduct 275 kV Longannet to Clydes Mill
- Reconduct 400 kV Windyhill to Inverkip
- Upgrade to 400 kV single circuit Windyhill to Longannet
- Reconduct 275 kV Mersey Ring
- Reconduct 400 kV Deeside to Daines

Diverse 30% ***Capex: £2,554m – £2,584m***

- Upgrade double circuit to 400 kV Beauly to Bonnybridge
- Upgrade double circuit to 400 kV east coast circuit from Beauly to Cockenzie
- Reconduct 275 kV Cruchan to Windyhill
- Upgrade to 400 kV all circuits Longannet to Strathaven
- Reconduct 275 kV Wisham to Smeaton
- Reconduct 275 kV Kintore to Longannet
- Reconduct 400 kV Windyhill to Inverkip
- Upgrade to 400 kV double circuit Windyhill to Longannet
- Reconduct 400 kV west and east coast interconnectors
- Reconduct 275 kV double circuits Harker to Blyth Harbour
- Upgrade to 400 kV east part of northeast network
- Reconduct 400 kV north west circuits (Harker to Penwortham, including the ring)
- Upgrade to 400 kV Mersey Ring
- Reconduct 275 kV Carrington to Macclesfield
- Reconduct 400 kV Daines to Carrington
- Reconduct 400 kV Deeside to Daines
- New circuit 400 kV Daines to Cellarhead
- New circuit 400 kV from Legacy to Ironbridge
- Upgrade to 400 kV Brinsworth to High Marnham
- Reconduct 400 kV Penwortham to Heysham
- Reconduct 400 kV circuits Rayleigh Main to Grain

Nuclear scenario ***Capex: £2,784m***

- Upgrade double circuit to 400 kV Beauly to Bonnybridge
- Upgrade double circuit to 400 kV east coast circuit from Beauly to Cockenzie
- Reconduct 275 kV Cruchan to Windyhill
- Upgrade to 400 kV all circuits Longannet to Strathaven
- Reconduct 275 kV Wisham to Smeaton
- Reconduct 275 kV Kintore to Longannet
- Reconduct 400 kV Windyhill to Inverkip
- Upgrade to 400 kV double circuit Windyhill to Longannet
- Reconduct 400 kV west and east coast interconnectors
- New 400 kV circuits west coast Kilmarnock South via Harker to Heysham
- Reconduct 275 kV double circuits Harker to Blyth Harbour
- Upgrade to 400 kV east part of northeast network
- Reconduct 400 kV north west circuits (Harker to Penwortham, including the ring)
- Upgrade to 400 kV Mersey Ring
- Reconduct 275 kV Carrington to Macclesfield
- Reconduct 400 kV Daines to Carrington
- Reconduct 400 kV Deeside to Daines
- New circuit 400 kV Daines to Cellarhead
- New circuit 400 kV from Legacy to Ironbridge
- Upgrade to 400 kV Brinsworth to High Marnham
- Reconduct 400 kV Penwortham to Heysham
- Reconduct 400 kV south west circuits (Ironbridge to Feckenham)

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ANNEX F – DISTRIBUTION NETWORK ANALYSIS

Description of detailed assumptions

There are a number of important assumptions, forming the basis of the analysis, which are required to fulfil the objectives for this part of the project. This annex describes in more detail than provided in Section 6 the assumptions used in the modelling exercise. All of the assumptions for the work were discussed and agreed with the Distribution Review Group.

The system reinforcement triggers

Voltage management

For the analysis undertaken in this study, the maximum amount of generation capacity which can be connected, on average, to each substation of the representative network model, without encountering voltage management difficulties, was defined.

The figures agreed, as described in the assumptions set out below, are based on the present design and operational conventions adopted by the industry. The modelling work includes some sensitivity studies on these maximum capacity figures.

System fault level

For the analysis in this work, an assessment is made as to the average, aggregate, amount of additional generation capacity which can be added to each substation in the representative distribution system model before the substation circuit breakers exceed their fault rating.

A, so-called, fault level *headroom* is defined at each substation level. This is based on actual average system fault level information provided by the DNOs for each voltage level in the model together with typical, real, circuit breaker ratings.

Exceeding the fault level *headroom* provides a further reinforcement 'trigger'.

Thermal rating issues

In this study, the maximum permitted contribution from a distributed generator to the thermal loading of the network is factored into the maximum permitted generator size for acceptable voltage management. This maximum aggregate generator capacity figure, per substation, also accounts for thermal rating issues – albeit as a secondary consideration to voltage management.

Both fault level *over-stressing* and voltage management difficulties are modelled to trigger a reinforcement solution. If the aggregate generation capacity connected to the substation being considered exceeds the maximum permitted for voltage management/thermal rating issues **or** if the fault level headroom is exceeded, then the model calculates and costs an appropriate reinforcement solution.

Reinforcement solutions

In order to determine the reinforcement costs associated with connection of the additional generation, it is necessary to consider the measure that might be required in the event of the existing network limits being breached. For the two principal reinforcement triggers, the agreed reinforcement solutions are as follows.

Voltage management and thermal rating issues

Where the target generation capacity[54] per DNO substation exceeds the maximum aggregate, average, generation capacity permitted (such that voltage management and thermal rating issues are avoided), then the solution in the modelling is to construct new substations – at that voltage level – until the required generation deployment can be accommodated.

For example, if the maximum average additional generation capacity at 11kV was 10MW per substation and there are one hundred 33/11kV substations, then the capacity – from a voltage management/thermal rating perspective – of the existing network is 10 x 100 = 1000MW.

If, now, the required additional renewable capacity per 33/11kV substation in a particular DNO area was, say, 1100MW, then the simple solution in this representative model, excluding the impact of any associated fault level solution, is to construct ten new 33/11kV substations. This would then provide for the additional 100MW of required generation capacity.

System fault level

Where the connection of the additional generation causes the fault level *headroom* to be exceeded, the reinforcement solution in the model is to replace the source circuit breakers[55] at the substation – exchanging them for new ones having a higher fault rating. The additional cost is in the replacement of substation switchboards.

[54] As determined by the renewable deployment scenarios.

[55] *Source* circuit breakers are those located at the substation supplying the circuit or circuits to which the generation is connected. A typical substation will have several source circuit breakers installed side by side. This collection of circuit breakers at a substation is sometimes referred to as a 'switchboard'.

The inter-dependency between voltage and fault level reinforcement solutions

The reinforcement solution for a voltage management problem is the installation of a new substation. New substations come with new circuit breaker switchboards.

It is important not to double-count costs in this respect and, in this regard, the cost model developed for this project gives an appropriate fault level headroom *credit* for each new substation installed. The result is that the solution to a voltage management problem may also avert a switchgear fault level problem which might otherwise have occurred.

The total cost figure comprises three elements

The total distribution reinforcement cost of accommodating the additional renewable generation onto the distribution networks comprises three cost elements:

- building of new substations as a solution to voltage management and thermal rating issues;
- replacement of circuit breakers (substation switchboards) as a solution to excess fault level issues; and
- circuit reinforcement costs – resulting from connection of generators remote from substations.

Generator sizes

The electrical size, or power rating, of individual generation schemes is significant in the assessment of distribution costs. Plant sizes vary by technology type and also by scenario.

For example, in the *Diverse* scenarios, the modelling assumes fewer large onshore wind turbines than, for example, in the *North Wind* scenarios and a larger proportion of smaller biomass generators than in the *Wind & Biomass* scenarios.

Table 19 – Generator size assumptions

	Baselines		***North Wind* and *Wind & Biomass***		***Diverse***	
Technology	Capacity (MW)	Proportion	Capacity (MW)	Proportion	Capacity (MW)	Proportion
Onshore wind	20	20%	20	20%	60	30%
	30	30%	30	30%	30	18%
	50	40%	50	40%	50	52%
	100	10%	100	10%		
Offshore wind	60	10%	60	10%	60	10%
	100	80%	100	80%	100	80%
	200	10%	200	10%	200	10%
Biomass	1	30%	5	5%	1	30%
	10	50%	30	65%	10	50%
	20	20%	50	30%	20	20%
CHP	5	20%	5	20%	5	20%
	10	60%	10	60%	10	60%
	20	20%	20	20%	20	20%
Other	5	100%	5	100%	5	100%

Maximum capacity at circuit and busbar level

For the assessment of voltage management (and thermal rating) issues, maximum aggregate generation capacity figures were agreed.

Figures were set for the maximum generation which could be connected, in aggregate, to the low voltage busbars of the substation at each level. Figures were also agreed and set for the maximum single generator size which can be connected to the substation circuits.

These figures are given in Table 20.

Table 20 – Maximum aggregate generation capacity per substation

Network voltage	**Maximum aggregate generation capacity on substation**	**Maximum individual generator size on circuit**
132kV	300MW	300MW
33kV	50MW	25MW
11kV	10MW	2MW

Note that the maximum aggregate capacity figure on each substation includes any individual generation connected out on the network. For example, at 11kV, voltage difficulties are deemed to become an issue if more than five 2MW generators were connected out on the 11kV network or if more than 10MW is connected directly to the 33/11kV substation.

Where an individual generator exceeds the maximum aggregate generation capacity threshold, it is assumed to be connected at the next voltage level up. An individual 15MW generator, for example, would not be able to connect at 11kV and is assumed to be connected at 33kV.

Circuit reinforcement costs

One element of the total costs is the reinforcement of existing lines and cables, such that the generation can be connected back to substations and load centres.

The analysis calculates the total land area served by each substation and assumes that the average distance from the substation to each generation scheme is one half of the radius of the notional 'capture area'.

Furthermore, for the primary substations, an 'inner radius' is defined. This allows the model to assess the impact of connecting a fixed proportion of the total generation capacity allocated to that substation within close range. This is likely to be the case with much of the renewable generation to overcome the lower size limit which can be connected to the circuits (as opposed to directly to the substation).

In the modelling, this inner radius is set at 1km and the assumption is made that 70% of the total generation capacity is located within this 1km radius of the substation.

In terms of circuit reinforcement costs, the following assumptions were made:

- all generators located within the inner radius (set at 1km) are connected via cable directly back to the substation at the cost of the generation developer. Therefore, nil system cost;
- all generators below the maximum permitted individual generation size, applicable to the voltage level, can be accommodated onto the network without reinforcement.

11kV connection

- All generators connected at 11kV, which are above the maximum individual generator size **and** are further than 1km from the substation, give rise to circuit reinforcement costs. 80% of the total costs of this reinforcement is assumed to fall upon the DNO, and is therefore included in the 'system' costs.
- All generators connected at 11kV, which are above the maximum individual generator size **and** are within 1km from the substation, give rise to some

circuit reinforcement costs. 25% of the total cost of this reinforcement is assumed to fall upon the DNO and is therefore included in the 'system' costs.

33kV connection

- All generators connected at 33kV which are above the maximum permitted individual generation size (i.e. 25MW) give rise to circuit reinforcement costs. Again, 80% of the total cost of this reinforcement is assumed to fall upon the DNO and is therefore included in the 'system' costs.

132kV connection

- All generators connected at 132kV give rise to an element of reinforcement cost[56], although, the majority of this cost is likely to fall upon the generation developer. 25% of the total cost of this reinforcement is assumed to fall upon the DNO and is therefore included in the 'system' costs.
- All of these assumptions are consistent with a shallow connection policy.

There is a further assumption that a proportion of the generation which could, by virtue of its size, be connected at 11kV, is actually connected at 33kV due to the proximity of suitable existing circuits. In the modelling, this figure is set at 15%.

Fault level contributions from distributed generation

The model assumes that all machines are of the synchronous type, operating at unity power factor and that their symmetrical fault contribution is equivalent to five times the rating of the machine.

The contribution from generators connected to the voltage level below is often material – albeit somewhat attenuated. In this study we assume that the contribution to the 132kV system fault level from generators connected at 33kV is one third (33%) of the contribution to fault level at 33kV. Also, the contribution to the 33kV system fault level from generators connected at 11kV is three quarters (75%) of the contribution to fault level at 11kV[57].

CHP generation

CHP generation is included in the baseline scenarios as part of meeting the 2010 targets. It does not, however, contribute to the increased levels of generation associated with meeting 20% and 30% targets in 2020.

With respect to the assessment of voltage management and thermal rating issues, only the CHP generation which is exported from the site, onto the network, is

56 It is accepted that at 132kV there are likely to be costs associated with connecting the generation which are not strictly cable or overhead line costs. In this study, circuit costs are used as a proxy for these additional costs.

57 These figures were obtained via some simple modelling carried out by one of the DNO contributors.

considered in the analysis. The model assumes that 58% of the total CHP capacity is associated with export onto the network[58].

However, for the assessment of fault level contribution, the full, installed, CHP capacity is used.

Asset replacement

Discussion with the Review Group led to an assumption that no credit should be given against the total reinforcement costs for asset replacement of circuit breakers which may already be planned.

Advanced condition monitoring techniques meant that there was a trend towards much longer operational lives for circuit breakers and that this would introduce considerable uncertainty with regard to routine replacement. In this respect, therefore, the analysis takes a worst, high-cost, case. It should be noted, however, that the sensitivity of total costs to this assumption is reasonably small.

New generation-only substations

It is possible that in areas of very high renewable generation deployment, some ‘generation only’ substations may emerge. In such cases, it may be that these substations may be able to accept higher levels of generation capacity before voltage management issues become a problem. This is because the absence of demand connectees at the generation level might allow the DNO to manage system voltage less tightly[59].

Furthermore, there may well be some economies of scale if the need for larger capacity, generation only, substations is foreseen – rather than the piecemeal reinforcement approach adopted in this analysis. For example, it is estimated that a substation having twice the capacity for accommodating generation could be built and commissioned for, maybe, 30% more than the cost of a new substation of half the capacity.

The impact of these effects is considered in the analysis.

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58 This figure of 58% is based on historic, national, ILEX data for CHP projects.

59 It should be noted that large departures beyond the voltage tolerance limits currently specified may also be problematic to other, locally connected, generators. Furthermore, since generators are also connectees to the system, any relaxation of the voltage limits may require changes to legislation.

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ANNEX G – ORIGINAL TERMS OF REFERENCE

Terms of Reference for Study on System Costs of Additional Renewables

1. Objective:

1.1 To provide order of magnitude estimates of the system costs of moving to an electricity system with a significantly larger renewables component than 10% during the period 2010 to 2020. The study would cover the whole of Great Britain.

1.2 The study should also report on three other items:

- The likelihood and possible causes of major cost increases if the proportion of renewables were to rise significantly beyond 30% beyond 2020.
- Risks of stranded assets arising from a move to more renewables and possible implications for consumer prices;
- Recent developments in policy towards renewables in Denmark.

1.3 The Consultants will report to a Government Steering Group comprising representatives of DTI, DEFRA and, in view of the large potential for renewables in Scotland, the Scottish Executive.

2. Definition of System Costs:

2.1 System costs would include, but not necessarily be limited to, differences between scenarios in respect of the following:

- the generation plant margin required to maintain comparable levels of security of supply, over seasonal and over very short timescales;
- the amount of swift response plant required to maintain comparable levels of security of supply, over seasonal and over very short timescales;
- expenditure on new and replacement transmission system equipment;
- expenditure on new and replacement expenditure on distribution systems;
- costs of operating the transmission and distribution systems, including the costs of new control systems and tools if appropriate;
- in all the above cases, appropriate allowance should be made for new and emerging technologies that might have a role to play in delivering system security and power transport objectives. One example might be energy storage

technologies such as Regenesys which might be used instead of conventional swift response plant.

2.2 It should be noted that there is no presumption that system costs under a high renewables scenario would necessarily be higher than under a low renewables scenario – they could be lower.

2.3 In the case of offshore generation projects, the cost of bringing power to the nearest point on shore should not be included as a system cost but rather be taken as part of the generation cost. However, the cost of onshore network reinforcement as needed should be included, as should the extra costs of taking offshore power longer distances by offshore cable before bringing it ashore.

3. Background Assumptions for year 2010:

3.1 It is proposed initially that a single view of the position reached by 2010 be adopted with the focus of the study being on differences between the way that system costs develop under alternative scenarios in the decade 2010 – 2020. This approach reflects the fact that there is greater certainty about developments in the period to 2010 than in the subsequent period and also the need to ensure the number of scenarios investigated is manageable.

3.2 The following assumptions are proposed which affect the position in 2010:

- A single Great Britain system for electricity trading and transmission access is in place by 2005;
- Measures are taken to ensure that 10 GW of CHP capacity is in place by 2010;
- Levels of renewable generation are in line with the Renewables Obligation, such that renewables reach 10% of the market by 2010;
- Where new capacity is required beyond the need for CHP and renewables as set out above, it should be assumed that it will be gas-fired.

3.3 The Consultants should specify details of a position for the Great Britain electricity market in 2010, covering the following and including some background description of the means by which this position is reached:

- Electricity demand level;
- The mix of and location of non-renewable generating capacity;
- Developments in electricity transmission and distribution networks;
- The detailed mix of renewables capacity (see below).

3.4 The Consultants should discuss the detailed assumptions for 2010 with the Steering Group, prior to them being finalised. The assumptions should also be discussed with representatives of the renewables industry and with Workstream 1 of the DGCG (see Annex A). It should be stressed that the assumptions for 2010 would be just working assumptions about the most likely outcomes given current knowledge, policies and measures and would not represent Government targets or views about the desirability of different shares for different types of renewables.

3.5 Depending on early conversations with the Consultants and other parties, it might be appropriate at a later stage to develop more than one view of the system in 2010.

4. Types of Renewables Capacity

4.1 A range of factors about individual renewables projects will determine the effect they have on system costs. The principal factors are:

- Geographical location (including onshore and offshore);
- Predictability. The greater the amount of unpredictable generation, such as wind, the greater may be the need for alternative forms of firm capacity and quick response capacity;
- Intermittency. Some forms of renewables, such as tidal, are predictable but may not provide capacity at times of peak demand – again, additional firm capacity may be needed;
- Scale. This will determine whether new renewables are connected to local distribution networks or to transmission networks and may affect the need for control systems on those networks.

4.2 It will be necessary to specify in broad terms how new renewables projects, both in the period to 2010 and in the range of scenarios for 2010-2020, fit into the above categories. It will be a matter for the Consultants, with the approval of the Steering Group, to determine the extent of detail that it is practicable to take into account.

5. Scenarios for Analysis:

5.1 The main focus of the analysis should be on the period from 2010 to 2020.

5.2 For the period 2010 – 2020 two Baseline scenarios should be developed, building on the single scenario developed for the period to 2010. The key difference between the two Baseline scenarios is that one would take a *high* view of longer term growth in electricity demand and the other would take a *low* view. The low view might also be consistent with widespread development of domestic scale CHP. Arising from this difference would be corresponding differences in the amount of electricity generation capacity, both renewable and non-renewable. In the Baseline scenarios, renewable generation remains limited to 10% of the overall market.

5.3 Further scenarios would explore the additional system cost (compared to the Baseline scenarios) of renewables rising to (a) 20% and (b) 30% of the electricity market by 2020. The definition of these scenarios would encompass not just the additional renewables generation but also the type of generation and generating capacity that the extra renewables would displace.

5.4 A range of such scenarios should be developed with the exact number and composition to be determined in discussion between the Consultants and the Steering Group. The objective would be to develop scenarios that would enable the plausible range of possible system costs to be assessed as well as considering the range of likely patterns of future renewables development. A minimum of 3 scenario "types" seems appropriate for the period beyond 2010, perhaps along the following lines:

- Most new renewables from large wind developments, mostly in the North;
- Wind remains the key technology but developments are smaller in scale and more widely distributed geographically;
- A wide spread of renewables technologies with particular emphasis on biomass and solar, mostly small scale and widely distributed geographically.

It is not envisaged that more than around 6 scenario "types" for renewables would be examined although there may be a case for developing scenario types in which the same renewables assumptions are used but against the background of differing assumptions for non-renewables displaced.

6. Summary of Scenario Analysis:

6.1 Each of the two Baseline scenarios would be compared against:

- type A scenario for (a) 20% renewables and (b) 30% renewables
- type B scenario for (a) 20% renewables and (b) 30% renewables
- and so on for remaining scenario "types"

to determine the difference in system costs between them. Initially, all scenarios would start from the single picture of the electricity system in 2010, although it might subsequently be necessary to consider alternative starting points (see Paragraph 3.5 above).

7. Risk of Major Cost Increases with More Renewables:

7.1 This element of the project considers in very broad brush terms the implications of levels of renewable generation well beyond 30%, whether in the period to 2020 or, more likely, over longer timescales. The aim is to try to assess whether there might be any substantial system cost discontinuities from further or faster expansion of renewables and what patterns of renewables development might trigger such discontinuities.

7.2 It is not envisaged that this element of the project be carried out through further detailed scenario analysis but through a more general consideration of the possible system limits, if any, to different types of generation.

8. Prices and Stranded Assets:

8.1 For each scenario comparison, an approximate estimate should be made of the impact that the extra (or lower) system costs would have on final consumer prices, on the assumption that the extra costs would, in one way or another be passed through to consumers. The Consultants are not asked to consider in detail the mechanism of cost recovery.

8.2 However, the Consultants should consider the extent to which stranded assets might emerge as a result of the shift to additional renewables and, although these would be sunk costs, the extent to which they might feed in to final consumer prices, perhaps through the price controls on the regulated monopoly distribution and transmission businesses.

9. Renewables in Denmark:

9.1 An additional and somewhat self-contained element to this project is to report on the current attitude towards further renewables development of the Danish authorities and, in particular, to understand the reasons behind the reported decision of the new Government to slow down renewables development. The Consultants should report whether the Danish experience has any lessons for the UK. Particular attention should be paid to the Danish experience of operating a system with a relatively high proportion of wind generation as well as to wider economic and political factors.

10. Sources of Information:

10.1 This exercise is not seen as carrying out original analysis of the impact of different sorts of renewable plant on the various aspects of system costs, but rather of absorbing the large amount of quite specialised pieces of work that are already being undertaken on different aspects of this issue. Information from these more specialist studies, some of them incomplete, should be used, together with the scenario development work, to build up a picture of overall system costs.

10.2 We expect the Consultants to draw on as wide a variety of work as they are able but they should ensure they have access to the work of the following:

- Work proceeding under the various workstreams of the DTI/Ofgem Distributed Generation Coordination Group;
- Work being funded by the DTI Renewable Energy and Embedded Generation Programmes;
- Work being undertaken by the GB Transmission Issues Working Group, chaired by the DTI;
- Work commissioned by the Scottish Executive on prospects for renewables and electricity networks in Scotland;

- Analysis prepared by David Milborrow and by OXERA for the PIU Energy Review and available on the PIU website.

Further information on these sources is given in Annex A and additional details will be provided to the Consultants on appointment.

10.3 The consultants should also seek the views of the three current high voltage transmission system operators in Great Britain, namely NGC, Scottish Power and Scottish and Southern Energy. The DTI and the Scottish Executive will provide contact suggestions for these companies.

10.4 The DTI will also provide the Consultants with suggested contact points in Denmark to take forward the work element specified in Section 9 above, although the Consultants are also encouraged to use their own contacts.

11. Timetable and Resources:

11.1 The project falls into 3 main elements:

- Scenario definition;
- Familiarisation with literature and current studies;
- Scenario analysis and costing;

Depending on the resources allocated, the first two of these elements could be taken forward concurrently. In what follows, it is assumed that work on the project starts around the beginning of June 20002.

11.2 Scenario Definition:

The degree of definition required is quite considerable, taking account of location factors and plant dynamics as well as the more familiar issues of fuel types and demand and generation patterns. It will be important to involve NGC and the Scottish Grid operators in this work. It is envisaged that the starting assumptions for 2010 and the definition of the two Baseline scenarios would be largely complete and agreed with the Steering Group by early July 2002. Additional scenarios for extra renewables by 2020 would be developed during July and the final pattern of scenarios for analysis agreed with the Steering Group by the middle of August 2002.

11.3 Literature Review and Current Studies:

There is a lot of material in this area, much of it technical and much of it only partly complete. It will be important for the Consultants to see unfinished studies in this area and, where appropriate, discuss these with the authors. A full understanding of the range and nature of the technical and economic impacts that different types of generating plant have on system costs will be essential to the final stage of the project. It is expected that this work will continue through both June and July 2002.

11.4 Analysis and Costing:

This involves bringing together the work on scenario definition and literature review. It will form the main body of the report. The Consultants are requested to produce a draft report for consideration by the Steering Group in the second week of September 2002, with a final report due by the end of September. Both the draft and final reports should cover the additional items set out in Paragraph 1.2.

11.5 Indicative Summary Timetable:

Consultants Appointed	Mid June 2002
2010 and Baseline scenarios agreed	Early July 2002
All scenarios agreed	Mid August 2002
Draft report	Early September 2002
Final Report	End September 2002

11.6 Overall Resources:

We would expect very approximately 100 person days of consultancy time would be needed to do justice to the scope of this project, although this figure should be regarded as no more than indicative. For example, consultants who are already very familiar with the issues involved might need rather less time.

11.7 Reporting:

The successful Consultants will be expected to start work on the project as soon as practicable after being offered the contract. The Consultants will be expected to maintain regular contact with the appointed officer in the DTI throughout the period of the project and to attend meetings with the Steering Group as required. About five to six meetings of the Steering Group are envisaged, broadly matching the main steps of the project as set out in Paragraph 11.5 above.

11.8 Deliverables:

The Consultants will need to design a database for presenting details of scenario assumptions and appropriate draft assumptions will need to be provided to the Steering Group, in a manner to be determined, in advance of meetings to finalise scenarios.

Twenty copies of the draft report should be submitted by 5th September 2002 and twenty copies of the final report should be submitted by 27th September 2002. Electronic copies of both the draft and final reports should also be provided in a format to be agreed.

11.9 Payment:

The DTI would prefer the whole project to be covered by a pre-determined fixed price and bidders are encouraged to tender on this basis. However, bidders may wish to specify additional or separate elements in the price to cover particular circumstances, for example the possibility that more than one 2010 starting position needs to be assessed (see Paragraphs 3.5 and 6.1 above). It is also envisaged that payment will be made in two stages: on receipt of the interim report and on acceptance of the final report.

12. Submission of Proposals:

Bidders are asked to provide full details of how they would seek to deliver the objectives and outputs set out in this Terms of Reference. In addition, they are also asked to provide the details asked for in the attached form (PF30) and to put forward any other achievable benefits of their proposal that they think relevant.

Proposals should be addressed to Richard Penn, ENP Directorate, DTI, Room 186, 1 Victoria Street, London SW1H 0ET and should be submitted by midday on Friday 31st May 2002.

13. Additional Information:

The contract will be awarded to the bidder whose proposal substantially fulfils the conditions described in this Terms of Reference and represents the best overall value for money. The Steering Group will evaluate and compare bids and take into account, among other things: relevant experience and past performance of the organisation concerned; their financial viability; their understanding of the project requirements; the suitability of their proposed organisational structure; procedures and quality controls; the calibre and experience of the team proposed; the extent to which team members will be engaged on other work during the project period or devoted to this project.

Bidders shall bear all the costs associated with the preparation and submission of their bids and bear any future costs incurred prior to the award of the contract unless otherwise agreed in writing with the DTI. The DTI reserves the right to undertake post-tender negotiations prior to the award of the contract.

ENP 3a/DTI

15th May 2002

ILEX

Quality Control Check Sheet

QUANTIFYING THE SYSTEM COSTS OF ADDITIONAL RENEWABLES IN 2020

Report Unique Serial No: 2002/080

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