2009 Great Britain Seven Year Statement

(May 2009)

GREAT BRITAIN SEVEN YEAR STATEMENT

May 2009

National Grid

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GB Seven Year Statement 2009

National Grid Electricity Transmission plc, acting in its role as Great Britain System Operator (GBSO), is pleased to present this 2009 GB Seven Year Statement (GB SYS), which covers the years 2009/10 to 2015/16 inclusive.

This is the fifth GB SYS we have produced. Under the British Electricity Trading and Transmission Arrangements (BETTA), which were introduced on 1 April 2005, National Grid, in its role as GBSO, became required to produce a single Seven Year Statement covering the whole of the Great Britain (GB) transmission system (i.e. the GB SYS) on an annual basis. The two Scottish transmission licensees are required to assist National Grid in preparing each GB SYS pursuant to their licence obligations.

The form of this 2009 GB SYS has been approved by the Authority and its main purpose is to assist existing and prospective new users of the GB transmission system in assessing opportunities available to them for making new or additional use of the GB transmission system in the competitive electricity market.

The subject matter of this 2009 GB SYS largely reflects that of earlier Statements, which in turn was developed over a number of years taking into account readers' preferences made known through annual customer surveys. Accordingly, this GB SYS contains a wide range of technical and non-technical information relating to the GB transmission system.

I hope you find our 2009 GB SYS both interesting and informative. Given the challenges facing the electricity industry over the coming 7 years and for 2020 and beyond, I would particularly welcome any comments you may have on both the style and the content of the document so we can fully consider any improvements for the 2010 GB SYS. An electronic questionnaire is available on our website for this purpose **Customer Survey Online Form**.

I look forward to receiving your views on the Statement, including suggestions on how it may be further improved.

Nick Winser, Group Director, Transmission

National Grid plc

May 2009

nationalgrid
The power of action.

GB Seven Year Statement
2009

Introduction to the Executive Summary

This 2009 Great Britain Seven Year Statement (GB SYS) is the fifth Statement to be produced since the British Electricity Trading and Transmission Arrangements (BETTA) came into effect on 1 April 2005.

With the introduction of BETTA, National Grid, in its role as Great Britain System Operator (GBSO), is required to produce a single GB SYS covering the whole of Great Britain on an annual basis. The two Scottish transmission licensees are required to assist National Grid in preparing the Statement pursuant to their licence obligations

This 2009 GB SYS presents a wide range of information relating to the transmission system in Great Britain including information on demand, generation, plant margins, the characteristics of the existing and planned GB transmission system, its expected performance and capability and other related information. Amongst other things, this information should assist existing and prospective new Users of the GB transmission system in assessing the opportunities available to them for making new or further use of the GB transmission system in the competitive electricity market in Great Britain.

This Executive Summary provides a brief description of some of the key points contained in the main text. For a more complete picture on any particular topic, including the terminology used, the reader is advised to consult the relevant section of the main text. In particular, readers unfamiliar with BETTA are advised to refer to the chapter in the main text titled "Market Overview" **Market Overview**, which provides a high level overview of BETTA and also reports on related issues such as governance, institutional and contractual arrangements, and for the first time, touches on the development of offshore generation and the timetable for implementation of the new offshore regime.

It should be noted that the demand forecasts and generation background, on which this document is based, are not National Grid's forecasts of the most likely developments over the next seven years but are the demand forecasts received from customers and the factual list of existing and proposed generation projects that have a signed connection agreement. Consequently, care must be taken when interpreting the results as there is a degree of uncertainty associated with both the level of future demands and the number of generation projects opening or for that matter closing. However, for comparison purposes we do include our own demand forecasts but due to commercial confidentiality we are unable to show the equivalent level of detail on future generation project developments.

The data and results presented in this summary are correct as at 31 December 2008 (the data freeze date) and do not include changes included in the Quarterly Updates which are issued on a regular basis (at intervals of approximately three months). The first Update will be issued soon after the main Statement and will report on changes that have occurred since the data freeze date.

Electricity Demand (See Chapter 2)

The main forecasts of electricity demand to be met from the GB transmission system presented in this Statement are based on information submitted by Customers who take (or propose to take) electricity from the system and consequently are not National Grid's forecasts. However, for comparison, our own view of demand growth is also included. Unlike the 'User' based forecasts, which include details of individual Grid Supply Point demands, the NGET forecasts are national projections for Great Britain.

Unless otherwise stated, all demand forecasts presented are in respect of the Average Cold Spell (ACS) winter peak and include transmission losses, distribution losses and exports to External Systems across External Interconnections. The forecasts are in respect of the time of simultaneous peak on the GB transmission system and are unrestricted (i.e. take no account of demand response/management by customers). This prudent approach in transmission planning is made on the basis that demand response/management by customers cannot be fully relied upon to be enacted at peak times.

User Based Forecasts

Correcting historical actual demands to ACS conditions eliminates the weather effects and gives a better indication of the underlying pattern of annual peak demand. Correcting winter weekday peak demands in 2008/09 to ACS conditions yields a provisional 'unrestricted' peak of 59.0GW; a decline of 2.4GW on the previous winter's ACS peak.

The major factor in the decrease in demand over the last year has been the effect of the economic downturn. General energy efficiency measures such as energy saving light bulbs have also contributed to the decrease. The decrease in demand also includes a 50MW reduction in interconnector exports at peak to Northern Ireland.

Peak unrestricted demand on the GB transmission system in ACS (average cold spell) conditions, as projected by the system 'Users', increases from the provisionally estimated outturn of 59.0GW in 2008/09 to 64.1GW by 2015/16. This represents a growth rate of 1.1% per annum as indicated in **Figure E.1** . **Figure E.1** includes recent outturns together with the current User forecasts of ACS peak demand on the GB transmission system.

Figure E.1

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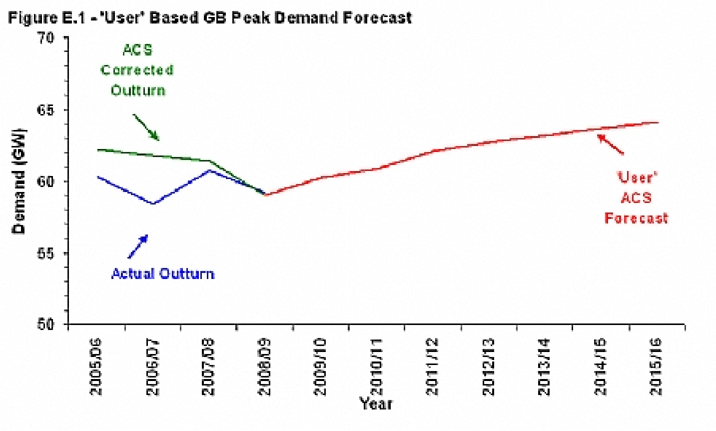

National Grid View of Demand Growth

We have also prepared our own 'base' forecast of peak demand and annual electricity requirements, together with 'high' and 'low' transmission system demand scenarios. For the 'high' and 'low' demand scenarios, combinations of favourable and adverse developments are assumed which yield high and low transmission system demands. For example, in the low scenario better progress towards the government's 2010 targets and beyond for combined heat and power and renewables is assumed, resulting in stronger growth in embedded generation. In contrast, in the high demand scenario there is a much slower take-up of such schemes and hence embedded generation. These assumptions, along with variations for other factors such as economic growth, result in a fairly wide range of outcomes for transmission system demand.

Figure E.2 compares our base, high and low demand forecasts with the User based forecasts. Under the 'base' forecast the ACS 'unrestricted' peak demand decreases from 59.0GW in 2008/09 to 56.9GW in 2010/11, and then shows minimal growth to 57.8GW in 2015/16.

Figure E.2

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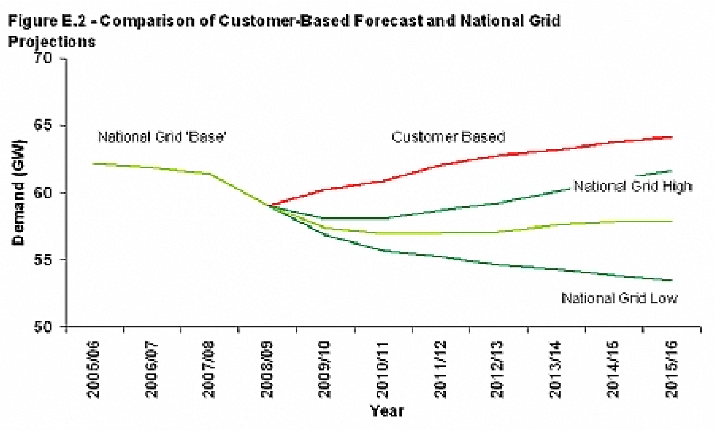

Throughout the period covered by this year's forecast, the User based forecast is more optimistic than National Grid's 'Base' forecast and is higher for all years than National Grid's High growth scenario projections. In the past, the User based forecasts have tended to underestimate the likely impact of embedded generation on system demand, which results in higher demand forecasts. Furthermore, the User based forecasts were submitted last June based on demand seen in 2007/08. The National Grid forecasts benefit from being based on demand seen in 2008/09, when peak demand fell against the background of an economic downturn.

In general, the level and location of generation remains the major factor in determining the need for transmission reinforcements. However, in some areas (e.g. where demand exceeds generation) it is demand that can exert the greater influence and as such there is an increasing need for accurate demand forecasts in terms of both level and location.

Generation (See Chapter 3)

Chapter 3 presents information on all sources of generation, which are used to meet the ACS Peak GB Demand. Accordingly, this chapter reports on all power stations directly connected to the GB transmission system, whether they are classified as Large, Medium or Small, all directly connected External Interconnections with External Systems and all Large power stations, which are embedded within a User System (e. g. distribution system).

In recognition of the uncertainties associated with the future, unless otherwise stated the information presented relates to existing generation projects and only those proposed new generation projects which are classified as "transmission contracted". Hence the SYS generation background is a factual list of contracted sites and is not a forecast of which generators are expected to remain in operation or which proposed new generation projects are deemed most likely to proceed to completion. Consequently, care must be taken when interpreting the overall capacity figures as a number of stations will close due to the Large Combustion Plant Directive (LCPD) and many of the proposed projects will not progress to a connection. In addition there may be some non-contracted projects not included within the SYS that may proceed to a connection during the seven years.

Figure E.3

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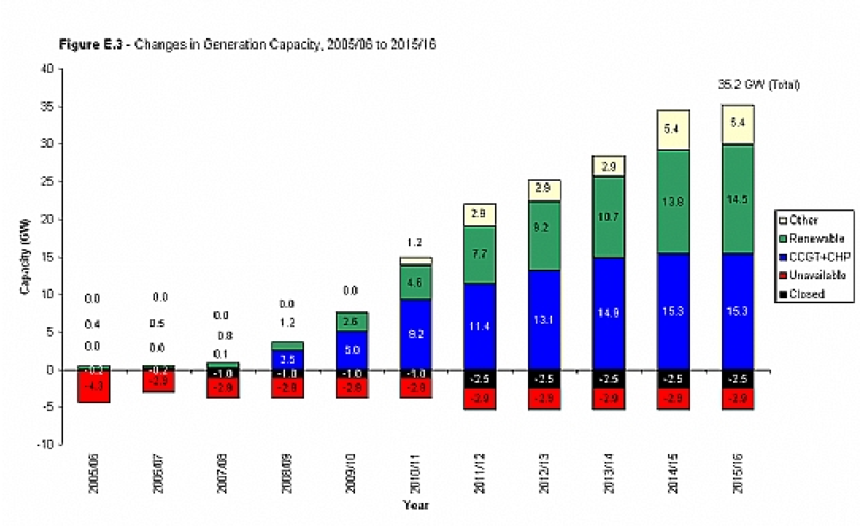

Figure E.3 illustrates the increase in generation capacity of plant since 2005/06. Notified reductions in capacity from plant closures and from plant being placed in reserve have been taken into account. However, no allowance has been included for those stations that will close on or before 31st December 2015 due to opting out of the LCPD. These closures amount to 12GW of coal and oil capacity and have been left in because of the uncertainty over closure date and the potential for them to be available at peak in 2015/16 if the peak is prior to Christmas.

A feature of the future commissioning stream, shown in Figure E.3, is the relatively high level of activity in relation to capacity increases indicated for the years 2010/11 (7.4GW) and 2011/12 (7.0GW). In this year some 16.1% of the new capacity is from Wind generation (mostly onshore) which is to be located in Scotland. Similarly, some 16.9% of the new capacity is from Wind generation (mostly offshore) which is to be located in England & Wales. It is worth remembering, however, that, in the event, there may well be a more graded increase in activity over a number of years. The fact that a project is currently 'transmission contracted' is not an absolute guarantee that the project will proceed to completion since there are other factors, which may also influence that outcome (e.g. financing, fuel prices, planning consents etc.).

Figure E.4

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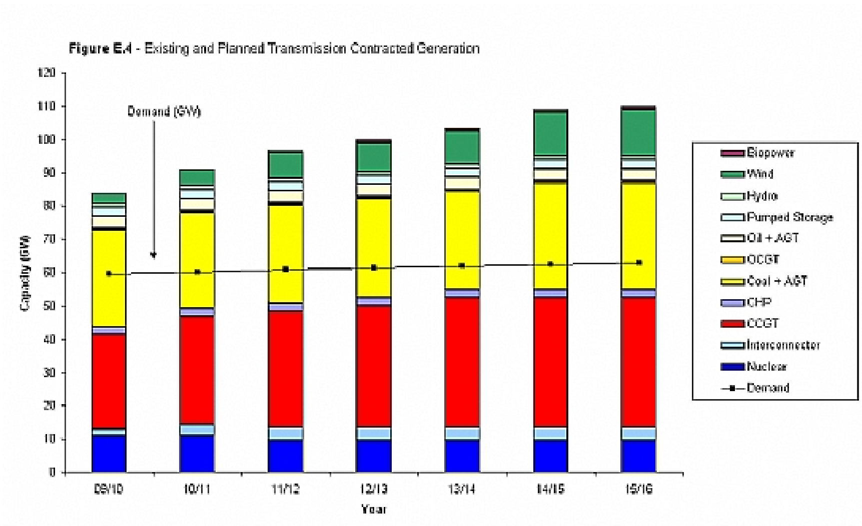

Figure E.4 illustrates the generation mix over the period from 2009/10 to 2015/16 and includes both existing and proposed new transmission contracted generation. The aggregate power station capacity (TEC and/or 'Size of Power Station') is reported to rise from 83.6GW in 2009/10 to 109.8GW by 2015/16. This represents an overall increase of 26.2GW, or 31.3% of the 2009/10 total, over the period from the 2009/10 winter peak to the 2015/16 winter peak. This net increase is made of the following:

- an increase of 10.3GW in CCGT capacity (+12.3%);
- an increase of 5.8GW in onshore wind generation capacity (+6.9%);
- an increase of 5.3GW in offshore wind generation capacity (+6.3%);
- an increase of 3.3GW in coal generation capability (+4.0%);

- an increase of 2.1GW in new import capability (+2.5%);
- an increase of 0.85GW in Biomass capacity (+0.5%);
- an increase of 56MW in Hydro capacity (+0.1%); and
- a decrease of 1.45GW in Nuclear Magnox capacity (-1.7%).

The largest change is due to the 10.3GW increase in CCGT plant capacity over the period. On this basis, the capacity of CCGT plant will overtake that of coal by 2010/11. By 2015/16, CCGT capacity will exceed coal capacity by 6.5GW and account for 32.0% of the total transmission contracted installed generation capacity. Note that this growth in CCGTs of 10.3GW excludes those stations under construction that are contracted to connect in 2009/10 e.g. Langage, Marchwood, Immingham, Starythorpe, Severn Power (phase 1) and West Burton (phase 1) which amount to 5GW. In addition there are a number of other CCGTs under construction e.g. Severn Power (phase 2), West Burton (phase 2&3) and Grain which amount to 2.6GW and are included in the 10.3GW figure.

The second largest reported increase is due to the growth in Wind generation, with onshore wind accounting for a 6.9% increase and offshore wind accounting for a 6.3% increase in overall capacity. Wind generation capacity (both onshore and offshore) is set to rise to 11GW by 2015/16. Currently around 1.8GW of wind is under construction with 1.2GW due to connect in 2009/10 and 0.6GW contributing to the 11.1GW growth over 2009/10 to 2015/16.

The above capacities do not include the embedded Medium and Small generation and embedded External Interconnections with External Systems. The capacity of such embedded generation sources is the subject of **Embedded and Renewable Generation**.

It should be remembered that the above figures reflect the current contracted position and take no account of future uncertainty. As mentioned previously, it is reasonable to suppose that further new applications for power station connections will be received and, at the same time, some existing contracts may be modified or terminated and some existing power stations will close.

Embedded and Renewable Generation (See Chapter 4)

The focus of this chapter is on embedded Medium and Small power stations and embedded External Interconnections with External Systems. Embedded Large power stations are reported in the previous chapter.

Much of the existing and future embedded generation is either in the form of combined heat and power (CHP) projects or in the form of renewable projects. This chapter considers these two types of generation source, their growth, the implications for the GB transmission system and other related issues. In so doing, the chapter also reports on non-embedded renewable sources of generation (e.g. wind farms).

Consistent with the Government's drive for growth in renewable generation a high proportion of the 26.2GW of contracted future Large or directly connected generation projects are wind farms, either onshore or offshore. Around 43% of the projected 11.1GW growth in such wind farm installed capacity is located in Scotland. Overall, wind farm capacity, both embedded and directly connected, is projected to grow from 5.0GW (2.1GW embedded and 2.9GW large/transmission connected) in 2009/10 to 16.0GW by 2015/16 with all the growth (11.1GW) coming from large/transmission connected. Embedded wind is seen by National Grid as negative demand and as a consequence is netted of the demand within the distribution networks.

National Grid recognises the importance of climate change issues and that the Government's targets for growth in CHP and renewable generation are likely to lead to a continuing growth in embedded generation. It is important for National Grid to play its part in facilitating this growth by ensuring that any transmission issues arising are appropriately addressed. At present, no insurmountable transmission problems associated with accommodating new embedded generation projects are foreseen. Indeed, the properties of the interconnected transmission system are such as to facilitate embedded generation growth regardless of location.

Nevertheless, this does not preclude the potential need for reinforcements to the GB transmission system, the extent of which would be a function of the system location of the new plant. For example, the extent, and therefore cost, of GB transmission reinforcement would be a function of the volume of offshore wind located off the England and Wales coast or onshore wind located in Scotland.

National Grid's responsibility in the Balancing Mechanism is to balance generation and demand and to resolve transmission constraints. The persistence effect of wind (i.e. its output is naturally subject to fluctuation and unpredictability relative to the more traditional generation technologies) coupled with the expected significant diversity between regional variations in wind output means that, while the balancing task will become more onerous, the task should remain manageable. Provided that the necessary flexible generation and other balancing service providers remain available, there is no immediate technical reason why a large portfolio of wind generation cannot be managed in balancing timescales.

It is anticipated that balancing volumes and costs will increase as the wind portfolio increases. National Grid estimation of these volumes and costs will be highlighted via a separate consultation report on future system operations which is due to be published in May 2009.

In the longer term, we do not think it likely that there will be a technical limit on the amount of wind that may be accommodated as a result of short term balancing issues, but economic and market factors will become increasingly important.

Plant Margin (See Chapter 5)

This chapter brings together information on generation capacity and forecast ACS unrestricted peak demand from previous chapters and examines the overall plant/demand balance on the GB transmission system by evaluating a range of potential future plant margins. The chapter concludes with a brief report on the related issue of gas and electricity market interaction.

It is emphasised that none of the plant margins presented in this chapter is intended to represent our forecast or prediction of the future position. The primary purpose is rather to provide sufficient information to enable the readers to make their own more informed judgements on the subject. The plant margins presented have been evaluated on the basis of a range of different backgrounds.

In view of the uncertainties, relating to the future generation position, three generation backgrounds have been considered. Each has been selected in recognition of the different level of certainty relating to whether the proposed new transmission contracted plant will, in the event, proceed to completion.

- Background 1: 'SYS Background' (SYS)

This background includes the existing generation and that proposed new generation for which an appropriate Bilateral Agreement is in place. The fact that a generation project may be classified as 'contracted' does not mean that the particular project is bound to proceed to completion. Nevertheless, the existence of the appropriate signed Bilateral Agreement does provide a useful initial indicator to the likelihood of this occurring.

- Background 2: 'Consents Background' (C)

A second useful indicator is whether plant has already been granted the necessary consents under Section 36 (S36) of the Electricity Act 1989 and Section 14 (S14) of the Energy Act 1976. This background includes all existing plant, that portion of plant under construction that has obtained both S36 and S14 consent where relevant, and planned future plant that has obtained both S36 and S14 consent where relevant. Any 'contracted' generation not already existing that requires S36 and S14 consent but has not obtained both is excluded from this background.

- Background 3: 'Existing or Under Construction Background' (E, UC)

This background is essentially the same as background 2 but excludes all future generation plant not yet under construction.

Figure E.5 compares plant margins derived from the customer based demand forecast with those derived from our own base view of future demand growth for the above three backgrounds; giving six sensitivities in all.

Figure E.5

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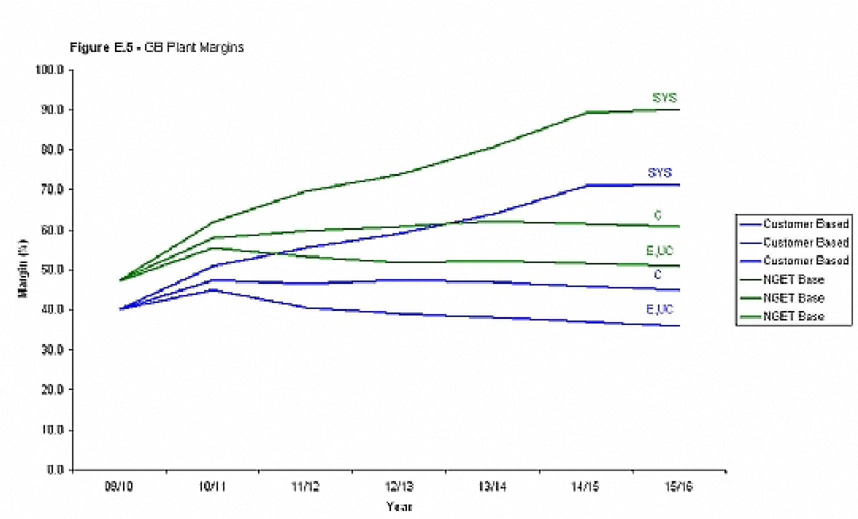

The main text considers a number of other factors, which can influence the value of plant margin. These include: as yet un-notified future generation disconnections (e.g. LCPD closures); the possible return to service of previously decommissioned plant (or the return to service of plant with TEC currently set at zero). The appropriate contribution towards the plant margin of generation output from wind farms is also considered as is the potential effect on the plant margin of exports (rather than imports) across External Interconnections and the sterilisation of generation capacity by virtue of its location behind a transmission constraint.

To illustrate this last point, additional plant margins have been calculated for a number of arbitrary assumptions relating to the availability of wind generation capacity at the time of the winter peak as per customer based forecasts. Figure E.6 displays plant margins for wind capacity availability assumptions of 40%, 30% and 0%. The SYS background (i.e. with an inherent 100% wind capacity assumption) is also included for comparison.

An alternative way to look at margins would be to look at the two lowest scenarios for each demand and generation background combination in 2015/16, i.e. the Existing & Under Construction backgrounds with firstly the customer based demand forecasts and then National Grid's demand forecasts, and then incorporate wind at zero capacity and the LCPD closures. Then these plant margins would fall from 36% to 13% and 51% to 26% respectively. Hence if the customer based demand forecasts did materialise then the current portfolio of generation and those under construction wouldn't be enough to meet margin requirements and some additional new plant would be required; whereas, if National Grid's demand forecasts did materialise then margins would be sufficient.

Figure E.6

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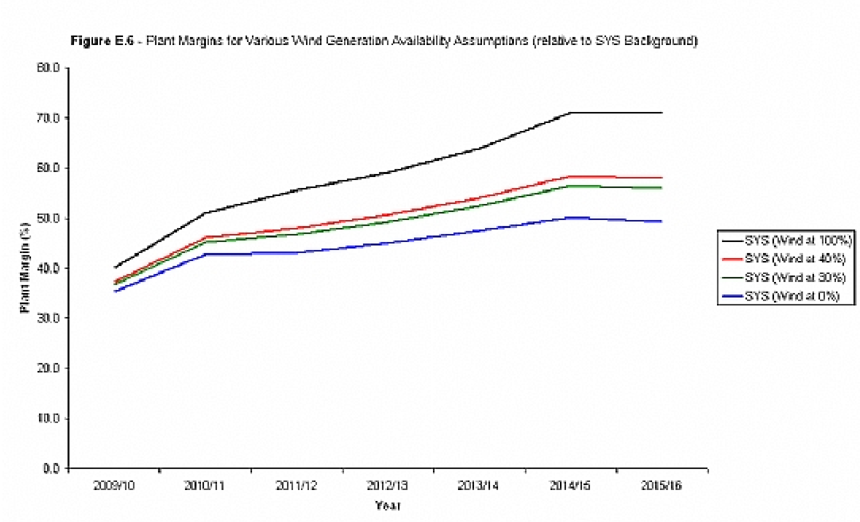

The margins displayed in **Figure E.5** and **Figure E.6** should not be taken at face value. The net result of the various uncertainties associated with the future plant/demand position is to produce a wide range of possible outcomes. In recognition of this, we have developed our own view of the likely developments into the future, which we consider alongside the SYS based backgrounds when undertaking our investment planning processes.

Transmission System Performance and Capability (See Chapters 6, 7 & 8)

The requirements placed on the transmission system depend on the size and geographical location of both generation and demand. However, it is generation that tends to exert the greater influence.

Figure E.7 summarises the Scotland (SHETL), Scotland (SPT), North, Midlands and South disposition of all transmission contracted generation (both existing and planned) in the years 2009/10 and 2015/16.

Figure E.7

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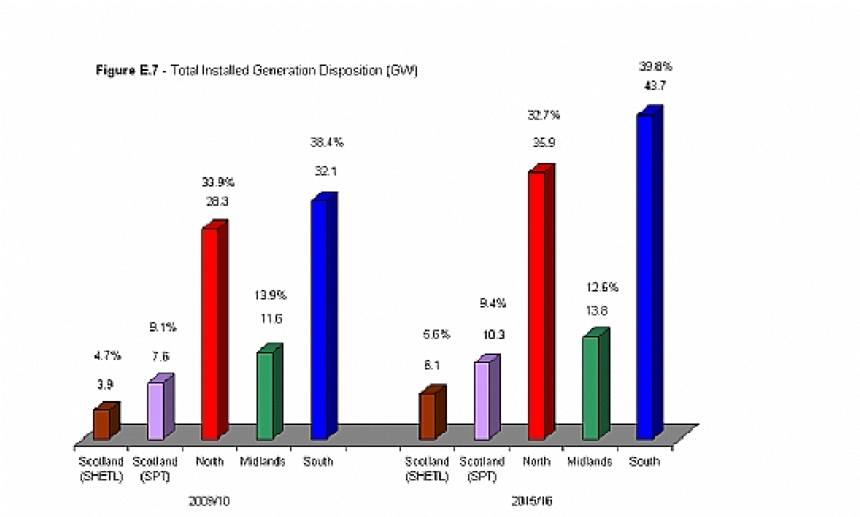

However, more importantly, it is the generation actually used in meeting the demand on the day, which determines the power flows at any given time. The 'GB Generation Ranking Order', which is explained in **GB Transmission System Performance**, is used to determine which generation is operated for the study purposes of this Statement.

By way of illustration, **Figure E.8** shows the Scotland (SHETL), Scotland (SPT), North, Midlands and South disposition of installed generation (also shown in **Figure 3.4**) together with the regional ACS peak demand disposition. In both 2009/10 and 2015/16, the installed generation in Scotland (SHETL), Scotland (SPT), North and the Midlands exceeds demand, in some areas by a substantial amount. In the South, there is a more even balance in 2009/10 with installed generation exceeding demand generation by a small amount. However, by 2015/16 installed generation exceeds demand significantly. Superficially, this would imply only relatively modest power transfers across the system.

Figure E.8

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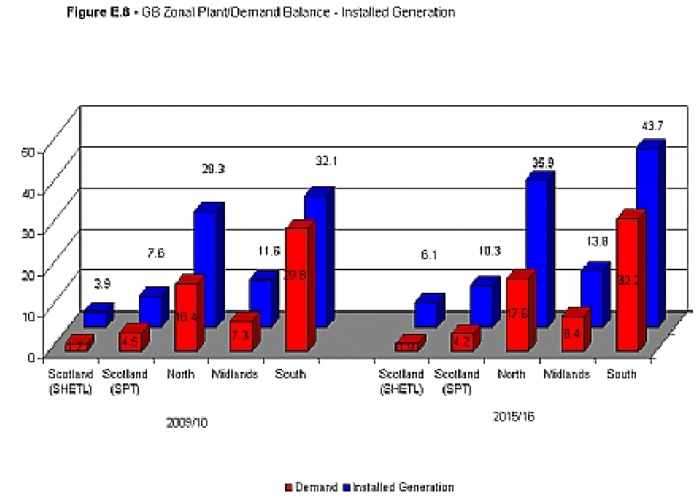

However, when the generation expected to be used to meet the demand is considered, a different picture emerges as illustrated in Figure E.9. Again generation in Scotland (SHETL), Scotland (SPT) and the North exceeds demand in both years. However, in the Midlands and South much of the generation becomes non-contributory (i.e. not used in meeting the demand) such that the demand exceeds generation, by a substantial margin in the South, in both years; implying higher power transfers from the northern parts of the system, through the Midlands to the South. The power transfers at the time of peak under the 'SYS background', are reported in more detail in **GB Transmission System Performance**.

Figure E.9

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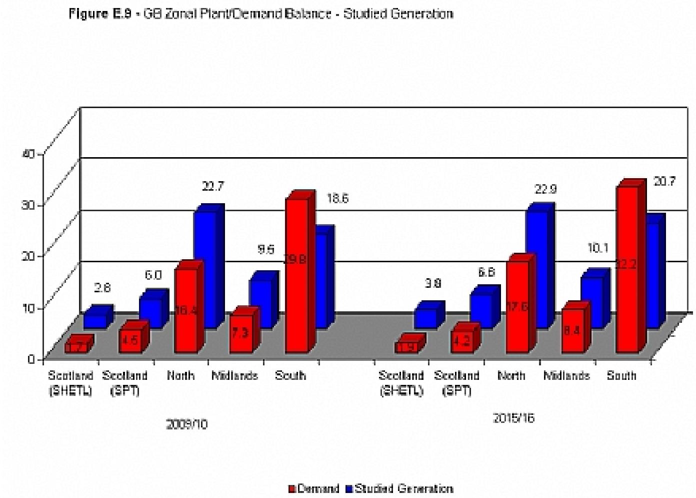

There are a number of boundaries on the GB transmission system that serve to illustrate the performance of the system. The main text of this Statement introduces 17 critical boundaries which, amongst other things, are used in determining the need or otherwise for transmission system reinforcement/investment. These boundaries relate to 17 SYS zones, which are also identified in the main text.

It should be noted that the 17 boundaries used in this Seven Year Statement serve as useful indicators of system capability but the apparent capabilities derived are dependent on the precise generation and demand background used. **Table 7.3**, of the main text, provides a useful reference overview of the power transfers, under the 'SYS background', across each of the 17 main system boundaries. The transfers are based on the expected contributory generation plant rather than installed capacity.

However, it is recognised that the 'SYS background' does not necessarily represent the most likely outturn. There is uncertainty associated with the demand forecasts and in particular with future generation developments. These factors will affect future power transfers, transmission system capabilities, the need or otherwise for transmission system reinforcements and the opportunities for making new or further use of the transmission system.

In view of this, we have presented the 'SYS background' transfers and capabilities against the backdrop of a range of probabilistic transfers. These probabilistic transfers reflect our current views on the likelihood of the various generation and demand uncertainties. This presentation is intended to provide a more meaningful view of future transfers, promote a better appreciation of the future uncertainty we face in planning our system and enable the reader to make more informed judgements on the opportunities for making new or further use of the transmission system.

The main text of this Statement (see **Transmission System Capability**) includes probabilistic transfers for all 17 boundaries. As an example, the results for two key boundaries are given in **Figure E.10** and **Figure E.11**. With the predominant high north to south power flows seen on our system, these two boundaries (i.e. the SPT to NGET boundary and North East and Yorkshire boundary) are particularly important.

Figure E.10

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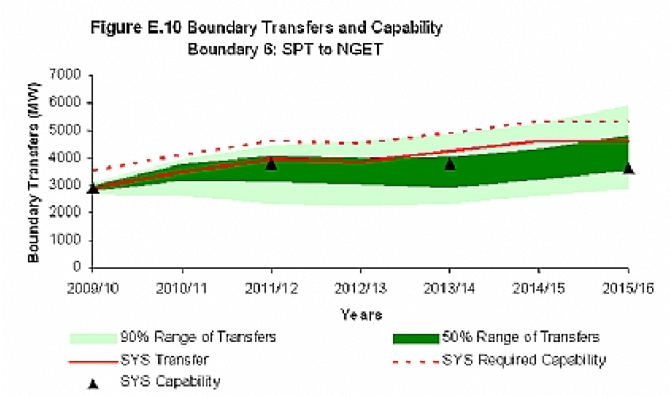

Figure E.11

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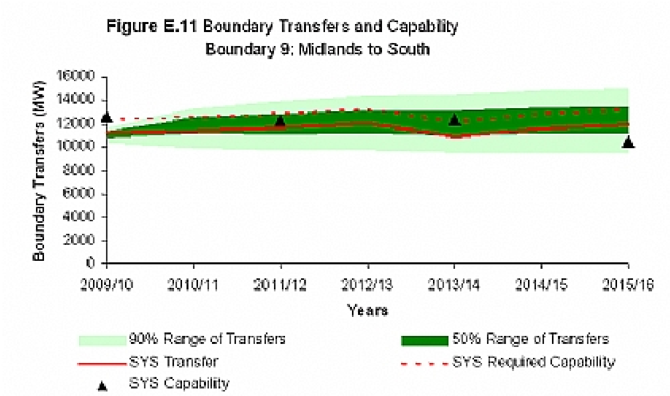


Figure E.10 and **Figure E.11** show the boundary transfer (SYS Transfer), required capability (SYS Required Capability) and actual capability (SYS Capability); all derived on the basis of the 'SYS Background'. These are displayed against a backdrop (shaded areas) of our current view of the probable transfer range.

The required capability is simply the boundary transfer enhanced by an allowance for security (referred to as the Interconnection Allowance) to take some account of variations in weather, generating plant availability and demand forecasting error either side of the boundary.

For the SYS Capability, two types of capability have been analysed: thermal and voltage. Where the voltage capability is less than the thermal capability, the voltage capability is given. The boundary capability may be further reduced at other times for stability reasons.

Turning now to the probabilistic transfer ranges (shaded areas); the darker shaded central band extends (on the vertical axis) from the 25th to the 75th percentiles of the range of probabilistically derived transfers, and thus includes 50% of all such transfers across the boundary at the time of system peak. The wider area, encompassed by the lighter shaded bands runs from the 5th to the 95th percentile and thus, together with the dark band, includes 90% of transfers. The remaining 10% lie outside the shaded range. The fan of probabilistically derived transfers can be compared with the deterministic planned transfer for the single deterministic SYS background.

It does not follow that the probabilistic transfer arising from a background considered to be likely will necessarily be captured within the envelope range shown on the diagram. Nor does it follow that all the most commonly occurring transfers have highly probable backgrounds. In our Generation Uncertainty Model (GUM), all backgrounds are equally probable. Nevertheless, the range of transfers displayed in the fan diagram does provide a very useful indicator of the most probable future planned transfer across the boundary given the possible combined effects of the various sources of generation and demand uncertainty. GUM can then be interrogated to reveal the details of any background underlying any transfer (point on the fan diagram) for further detailed analysis.

In the example given in **Figure E.10**, the SYS Planned Transfer lies towards the top of the probabilistic range of Planned Transfers while the SYS capability is in the lower part. There is hence a chance of lower peak flows than suggested by the SYS background; however, significant reinforcements will nevertheless be required in the very near future to facilitate even the lower parts of the range of probabilistic transfers.

In the example given in **Figure E.11**, over the latter part of the planned period, the SYS Planned Transfer lies within the range of the probabilistic transfers. At the same time, the SYS capability falls to the lower end of the probabilistic range which indicates a high probability of further reinforcements being required.

This presentation, which is reported in detail in the chapter on **Transmission System Capability** in the main text, is useful for highlighting issues around the timing of transmission reinforcements too far ahead of need and also for illustrating future opportunities. Please note that, whilst the 'SYS capabilities' displayed on **Figure E.10** and **Figure E.11** are appropriate for the 'SYS background' and 'SYS transfers', they do not necessarily correspond to the backgrounds covered by the probabilistic transfer range. Each background captured within the probabilistic analyses will have a unique set of boundary transfers and boundary capabilities.

The following provides a summary of the key indications for the future development of the GB transmission system taking account of the transfer levels and the boundary flows for the 'SYS background'; however, these developments need to be considered in light of the probabilistic potential range of flows.

- The major North-South flow boundaries B1 (SHETL North West Export), B2 (North to South SHETL), B4 (SHETL to SPT), B5 (North to South SPT), B6 (SPT – NGET), B7 (Upper North), B11 (Northeast & Yorkshire) and B16 (Northeast, Trent & Yorkshire) all show steady growth in power transfers throughout the SYS period. This is a result of an increased power export through Scotland and into England, due primarily to contracted renewable energy developments throughout Scotland;
- For B8 (North to Midlands) and B9 (Midlands to South) the power transfer fluctuates with generation changes north of the boundary however there is a general trend of increasing power transfer across the boundary.
- Central London import (B14) show a trend of steadily increasing transfers reflecting the increasing demands due to the Olympics and the lack of new generation projects within this zone;
- West Midlands import (B17) shows an initial reduction in transfer due to generator connection, with very little change across future years due to a balance between increasing demands and some generator openings;
- There is a general trend with reducing transfers across the South Coast import (B10), South & Southwest import (B12) and South West import (B13) reflecting new plant that might be expected to commission in the South and Southwest in line with present contractual positions.

There is a general trend with reducing transfers across South & Southwest import (B12), the South Coast import (B10) and South West import (B13) throughout the SYS period, reflecting new plant that might be expected to commission in the South and Southwest in line with present contractual positions.

In view of the uncertainty associated with the ‘SYS background’, the timing of the construction of infrastructure reinforcements is managed such that investments are made to well defined system requirements. This means that, generally, construction is deferred as far as is practicable to avoid undertaking investments that may turn out to be unnecessary, e.g. where transmission contracted generation does not in the event proceed. At the same time, in recognition of the individual TOs' obligations relating to the facilitation of competition, flexibility is planned into the GB transmission system such that it does not unduly inhibit the development of future projects and more recently the potential developments associated with strategic investment which is discussed in more detail in Chapter 8. However, we do ensure that we can provide an efficient, co-ordinated and economic system, compliant with the security standards, as required by the Electricity Act 1989 and the Transmission Licences.

A number of significant connection and infrastructure reinforcements to the GB transmission system are currently planned. In addition to the construction of new overhead lines and substations, these include the use of devices that not only maximise the use of the existing transmission system thereby limiting environmental impact, but also enable rapid network modifications to meet changing system requirements. To this end we use, amongst other things, quadrature boosters, which are capable of being relocated at a later date together with Relocatable Static Var Compensators (RSVCs). We have also authorised the reprofiling (i.e. retensioning of the overhead line circuits to reduce the sag between towers) of strategic overhead line circuits to increase the permitted operating temperature and thereby increase their load carrying capability.

By exploiting the capability of the existing transmission system through the installation of quadrature boosters and reactive compensation and overhead line conductor re-profiling, we will continue to maximise the use of our existing lines.

Opportunities for New Generation and Demand (See Chapter 9)

Generation Opportunities

As in previous years, Figure E.12 provides an indication of the opportunities for new generation across the 17 SYS Study Zones. The opportunities are interpreted as the ability to connect new generation without an associated need for major transmission reinforcement, which could in turn lead to delays caused by the need for planning consent and possible Public Inquiry. The red areas on the diagram would imply limited opportunity for connection in those zones given the level of transmission reinforcement required. Whilst the diagram correctly represents the opportunity for connection to a compliant network, it should be noted that Ofgem’s open letter dated 8th May provides the opportunity for new generation projects to connect under a derogation in advance of the wider system reinforcements being delivered. This interim measure is intended to be in operation until the implementation of the enduring transmission access arrangements which are currently being consulted upon with the industry. We therefore advise customers to contact National Grid if they are interested in making a connection to the transmission system so that the likely lead times for connection can be properly assessed against the background commercial and regulatory framework.

In the generation context, opportunities are interpreted as the ability to connect new generation without an associated need for major transmission reinforcement, which could in turn lead to delays caused by the need for Planning Consent and possible Public Inquiries.

Figure E.12 separates the 17 SYS Study Zones into five opportunity groups, namely: VERY LOW, LOW, MEDIUM, HIGH and VERY HIGH. The figure also provides an indication of the capacity of new generation that can be accepted in the individual zones of each opportunity group without the need for major transmission reinforcement.

It does not follow that all the generation capacity within an opportunity group could be located at one site within a zone. In some zones, for example the London Zones, a considerable spread would be necessary. Nor does it follow that the capacities indicated for each zone within an opportunity group could be accepted together. Moreover, please note that there is little opportunity for further connections in the northern zones.

Whilst levels of opportunity have been attributed to the five opportunity groups, it does not follow that the full opportunity capacity indicated could be used up without further detailed consideration. For instance, whilst the Central South Coast (zone 16) falls into the ‘medium opportunity category, any additional development might require major transmission reinforcement.

The proposed connection of a significant volume of new transmission contracted generation in the SHETL area, substantially made up of wind farms, is dependant on the completion of transmission reinforcements, including the proposed Beauly/Denny transmission reinforcement. The Beauly/Denny reinforcement is included as part of the SYS background for commissioning by 2013/14. However, elements of this reinforcement are currently the subject of a Public Inquiry and, consequently, the final commissioning date may vary, which would impact the opportunities.

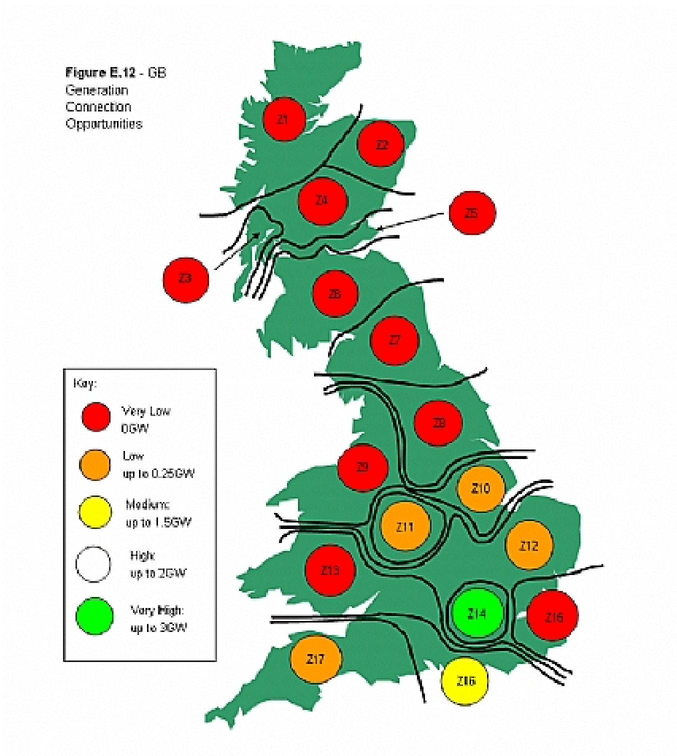
The analyses of boundary power transfers show that, with the material increase in new generation (26.2GW) planned for the next seven years, the resultant power flows through the Scottish and English grid systems to the South would require significant reinforcement. On this basis, it would be unlikely that any new applications for generation projects in Scotland or the north of England can be accommodated within the seven year period covered by this Statement. However, the proposed new transmission access rules (see below) are expected to change the emphasis by providing an opportunity for earlier transmission access for new generation projects.

The above guidance is necessarily general and emphasises the need to consider individual prospective generation developments on their merits at the time of application. A message arising from the guidance is that new generation located in the South is less likely to incur the need for major inter zonal transmission reinforcement and possible time delays than generation located in the North.

Notwithstanding the above opportunity messages, we will continue to comply with our licence obligations to make offers and will endeavour to meet our customers requirements including those relating to timescales.

Figure E.12

Click to load a larger version of FigureE.12 image



<u>Transmission Access Review</u>

The current transmission access review is also relevant in the context of future opportunities for generation access to the GB transmission system.

This review was announced in the Government's Energy White Paper 2007 and is being led by Ofgem and the Department for Business, Enterprise and Regulatory Reform (BERR) now DECC. The review covers the present technical, commercial and regulatory framework for the delivery of new transmission infrastructure and the management of the existing grid capacity to ensure that they remain fit for purpose as the proportion of renewable generation on the system grows.

Access to the GB transmission system is provided through arrangements with National Grid, acting as GBSO, under the Connection and Use of System Code (CUSC). The CUSC sets out the contractual framework for connection to, and use of, the GB transmission system. The CUSC has applied across the whole of Great Britain since BETTA was introduced on 1 April 2005.

The review includes the consideration of different models of transmission access, and to support this part of the review, National Grid has raised a suite of CUSC amendments and charging methodology modifications which could be used as building blocks to implement a number of different access models. Each of these models could be expected to provide an opportunity for earlier transmission access to new generation projects.

Strategic Investment

The information contained in this year's SYS does not reflect the recent work undertaken for the Energy Networks Strategy Group (ENSG) – Our Electricity Network – A Vision for 2020. Whilst the work carried out for ENSG identifies a set of transmission reinforcements that would facilitate the connection of renewable generation to help meet the Government's 2020 climate change targets, there is still further work required to agree a revised regulatory regime to deal with this anticipated investment. It is expected that a new regulatory regime will be developed during 2009 and these reinforcements may then form part of the SYS background in 2010.

Demand Opportunities

New demand of up to 150MW could be connected within most zones without requiring major transmission reinforcement.

An exception might be the introduction of such a step-change of load at certain points within or around some southern areas. For example, the London area has a large demand; approaching one tenth of the GB system peak demand. The London boundary is close to its thermal limit although planned work will ensure continued compliance. A large step-change in demand might, dependent on exact location, require major reinforcement. Each case again needs to be considered on its own merits.

Market Overview (see Chapter 10)

Chapter 10 provides an overview of BETTA and reports on related issues such as governance, institutional and contractual arrangements, and for the first time, touches on the development of offshore generation and the timetable for implementation of the new offshore regime.

Offshore Electricity Transmission

The arrangements described are subject to continual change and review either via legislative processes or through normal electricity industry governance. In addition to this, Ofgem and DECC are currently working together to implement a new regulatory regime for electricity transmission networks offshore. This is intended to enable significant volumes of offshore renewable generation to connect from UK offshore waters.

The Energy Act 2004 provides powers for the Secretary of State to make changes to electricity codes, agreements and transmission and distribution licences for purposes connected with offshore transmission or distribution. A final consultation on the regulatory framework for the offshore regime was issued by Ofgem and DECC in March 2009. This consultation contains the changes that the Secretary of State is expected to designate in June 2009.

From June 2009 (Go-active), it is expected that a 12 month transitional period will commence prior to full Go-live of the regime in June 2010. From Go-live onwards it will be a prohibited activity to own transmission equipment in offshore waters (which is deemed to be equipment operating at greater than or equal to 132kV) without holding a transmission licence.

From Go-live, National Grid's role as GBSO will extend to cover offshore areas (the Renewable Energy Zone). This means that National Grid will take responsibility for operating any offshore transmission assets.

The main feature of the new regime is the proposal to allocate offshore transmission licences (and hence the ownership of offshore transmission equipment) via a competitive tender process.

During the transitional period from Go-active to Go-live, Ofgem will run transitional tenders to identify the Offshore Transmission Owners (OFTOs) for offshore generators who are either already operational or have satisfied certain criteria and are progressing with the design and construction of their connections to shore. In parallel with this activity, National Grid will be revising the contractual arrangements with these sites to reflect the fact that, from Go-live, these sites will connect to the transmission system at the offshore platform rather than at the onshore point of connection. This will result in these offshore users entering into Bilateral Connection Agreements with National Grid, in the same way as onshore transmission connected generation.

Looking further forward, offshore users will apply to National Grid for connection to the transmission system in the same way as any other user. National Grid has transmission licence obligations to respond to an application to connect with an offer within three months of such an application. This Initial Connection Offer will detail the onshore works required to connect up the offshore developer. It will also take account of any information provided by the offshore developer in terms of likely offshore cable routes, landing points etc, but in the absence of such information will contain high level assumptions about the likely offshore transmission requirements. Ultimately, National Grid will ensure that any offer provided to an offshore user will be in accordance with its transmission licence obligations to act in an economic and efficient manner.

Once signed, the offer will trigger a tender process, to be run by Ofgem, to identify an OFTO for that connection. National Grid expects to provide information from the offer to inform the tender process. Once an OFTO has been identified, a Transmission Licence will be granted and the OFTO will accede to the SO-TO Code. Once the OFTO has acceded to the STC, then National Grid will interface with the OFTO in a similar way to the way in which it interfaces with the Scottish Transmission Companies. The OFTO will provide National Grid with a Transmission Owner Construction Agreement (TOCA) which describes the offshore works to be undertaken.

National Grid will then incorporate these works into the offer to the offshore user via an Agreement to Vary. Once this is signed, the construction activities will begin.

Some of the expected key milestones are given below:
March 2009: Final consultation on the Offshore Transmission Regime issued by OFGEM and DECC
March 2009: Crown Estate receives bids for Round 3 exclusive licences
May 2009: Commencement of section 92 of the Energy Act 2004 and section 44(1) and (2) of the Energy Act 2008 to enable the Authority to make regulations to enable the first round of tenders to begin shortly after Go-active
24 June 2009: Go-active commencement of sections 90 and 91 of the Energy Act 2004
Summer 2009: First tenders commence
From summer 2009: The Crown Estate announces preferred bidders for Round 3 zones
June 2010: commencement of sections 89 and 180 of the Energy Act 2004 and section 44(3) of the Energy Act 2008

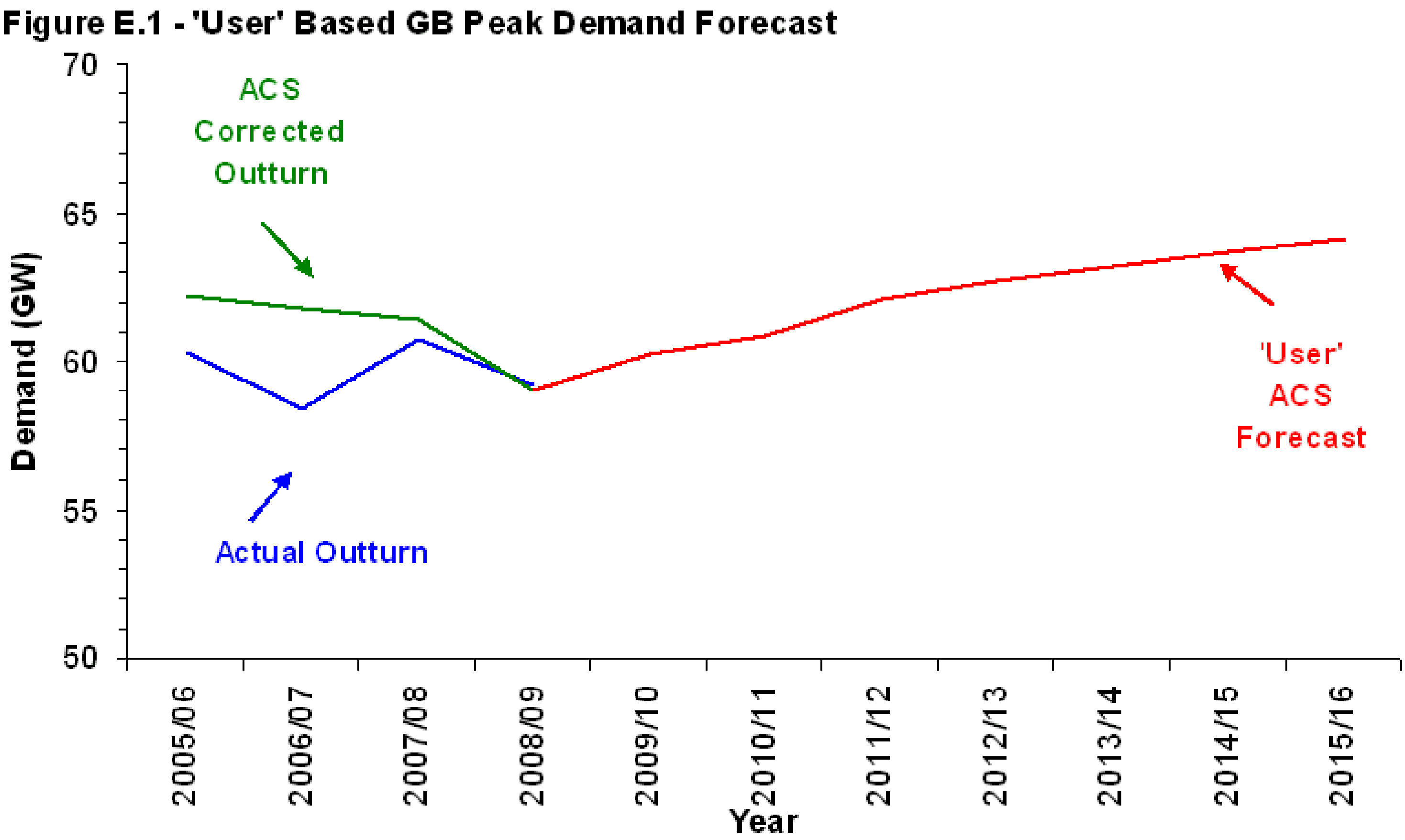


Figure E.1 - 'User' Based GB Peak Demand Forecast
ACS Corrected Outturn
Actual Outturn
'User' ACS Forecast
Demand (GW)
70
65
60
55
50
2005/06
2006/07
2007/08
2008/09
2009/10
2010/11
2011/12
2012/13
2013/14
2014/15
2015/16
Year

Figure E.2 - Comparison of Customer-Based Forecast and National Grid Projections

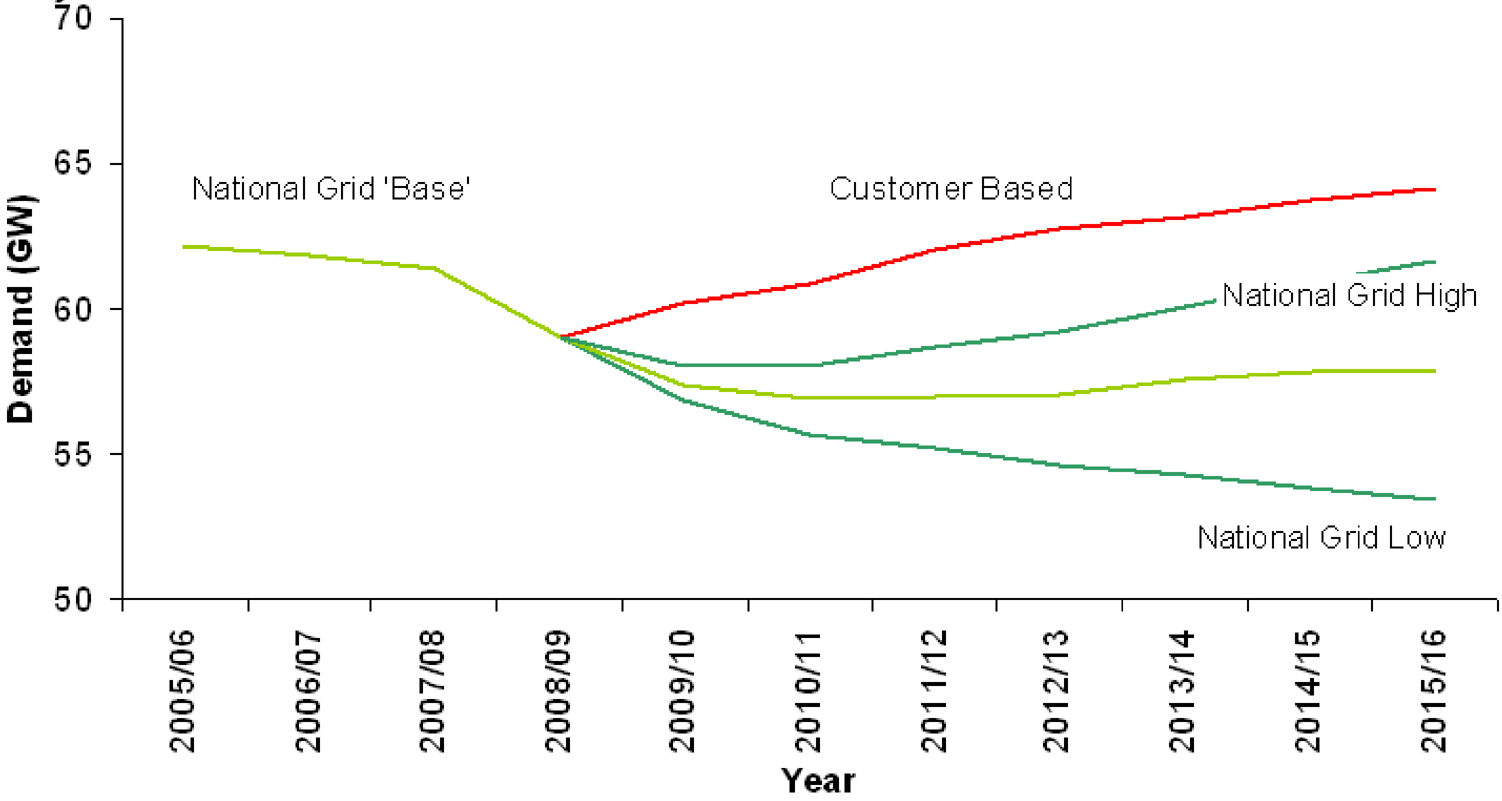


Figure E.3 - Changes in Generation Capacity, 2005/06 to 2015/16

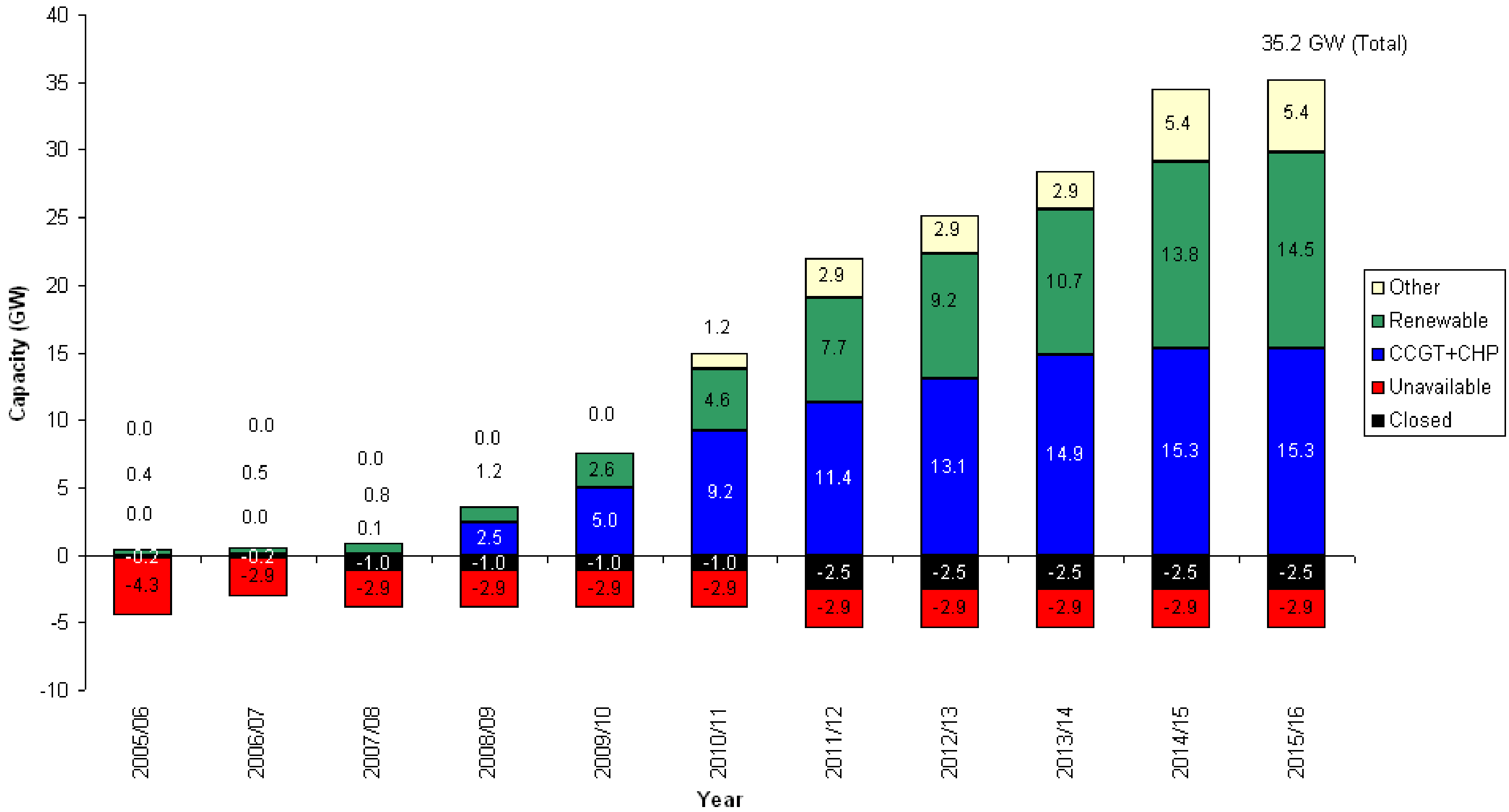


Figure E.4 - Existing and Planned Transmission Contracted Generation

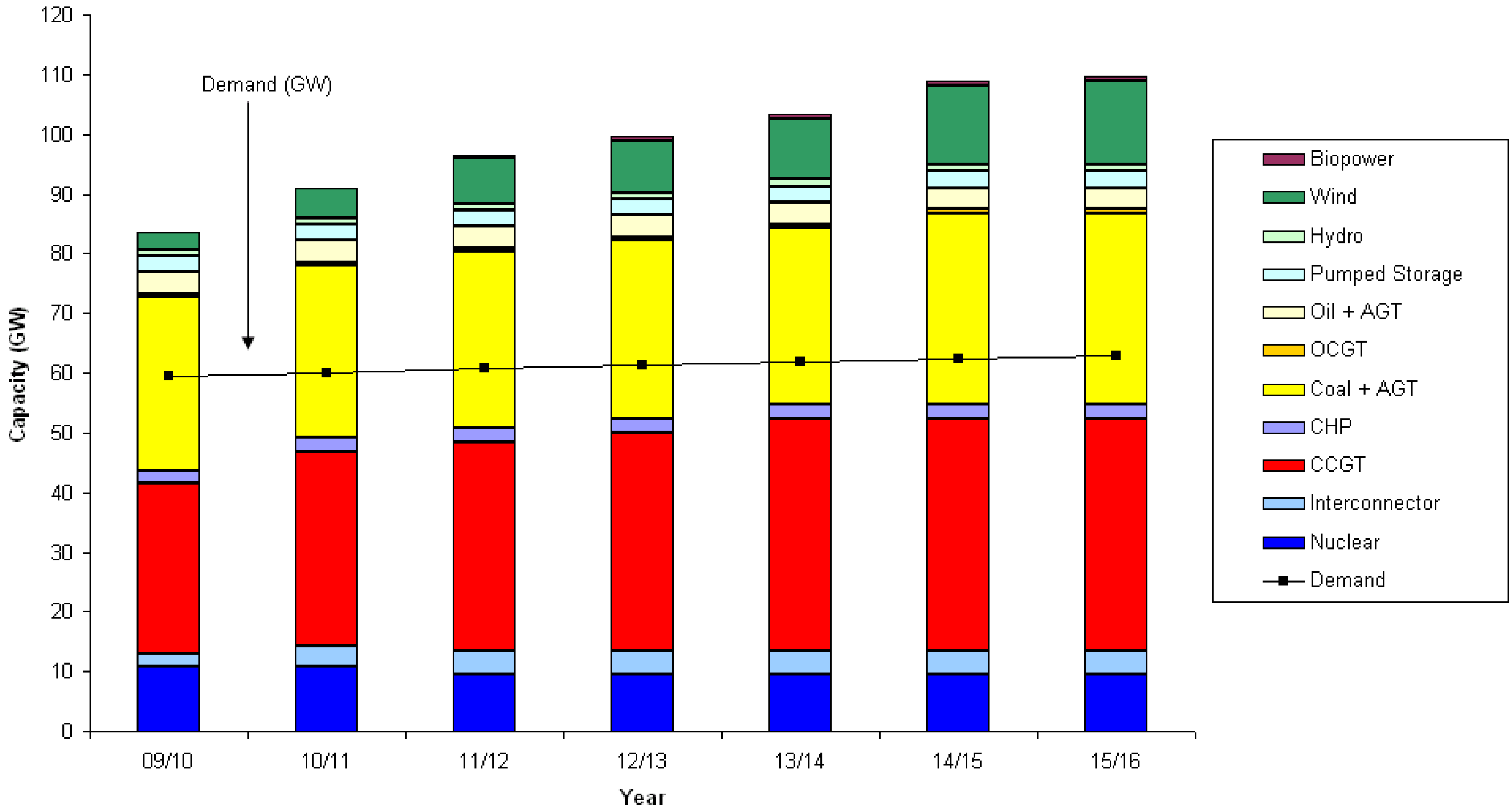


Figure E.5 - GB Plant Margins

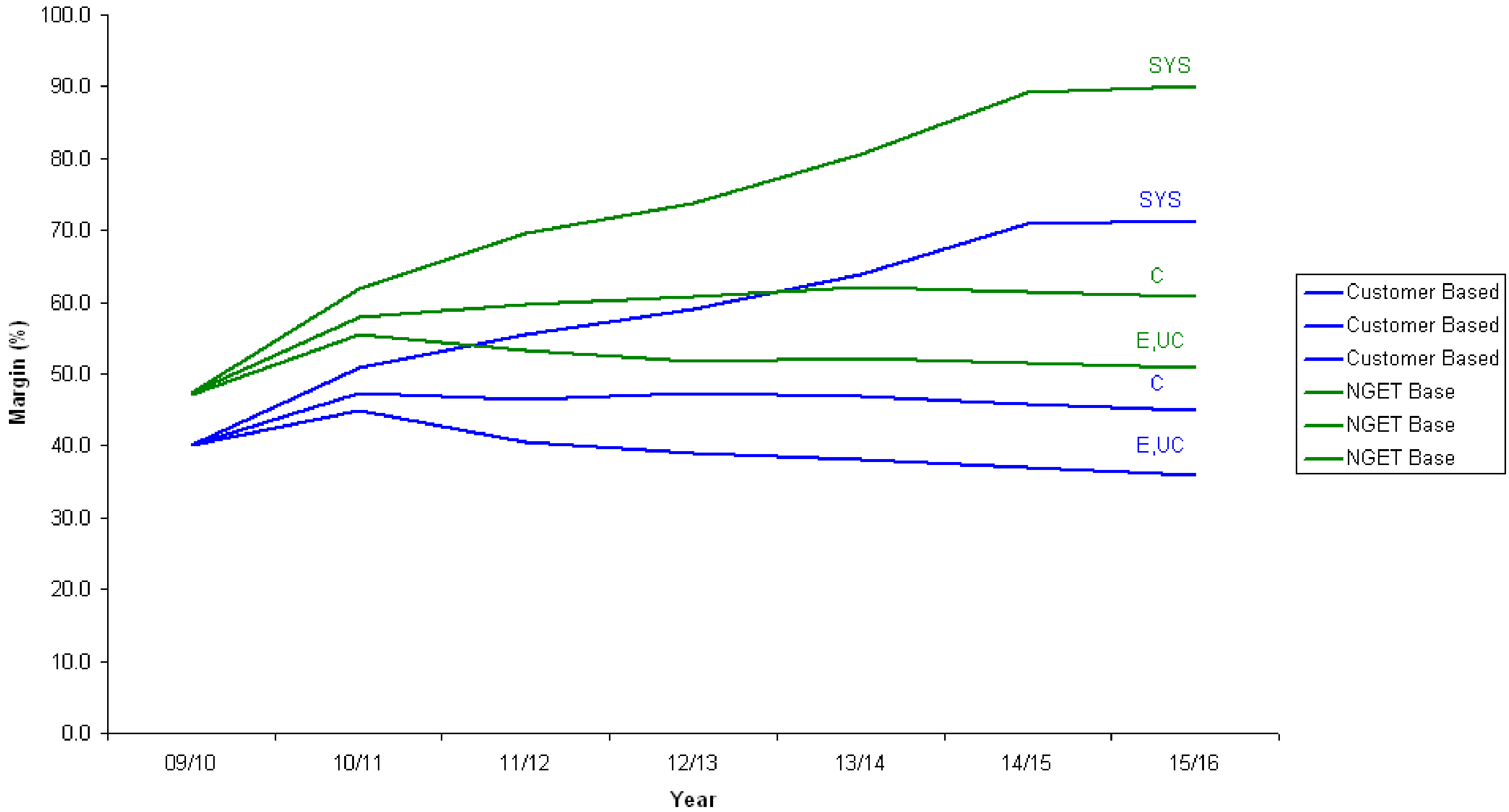
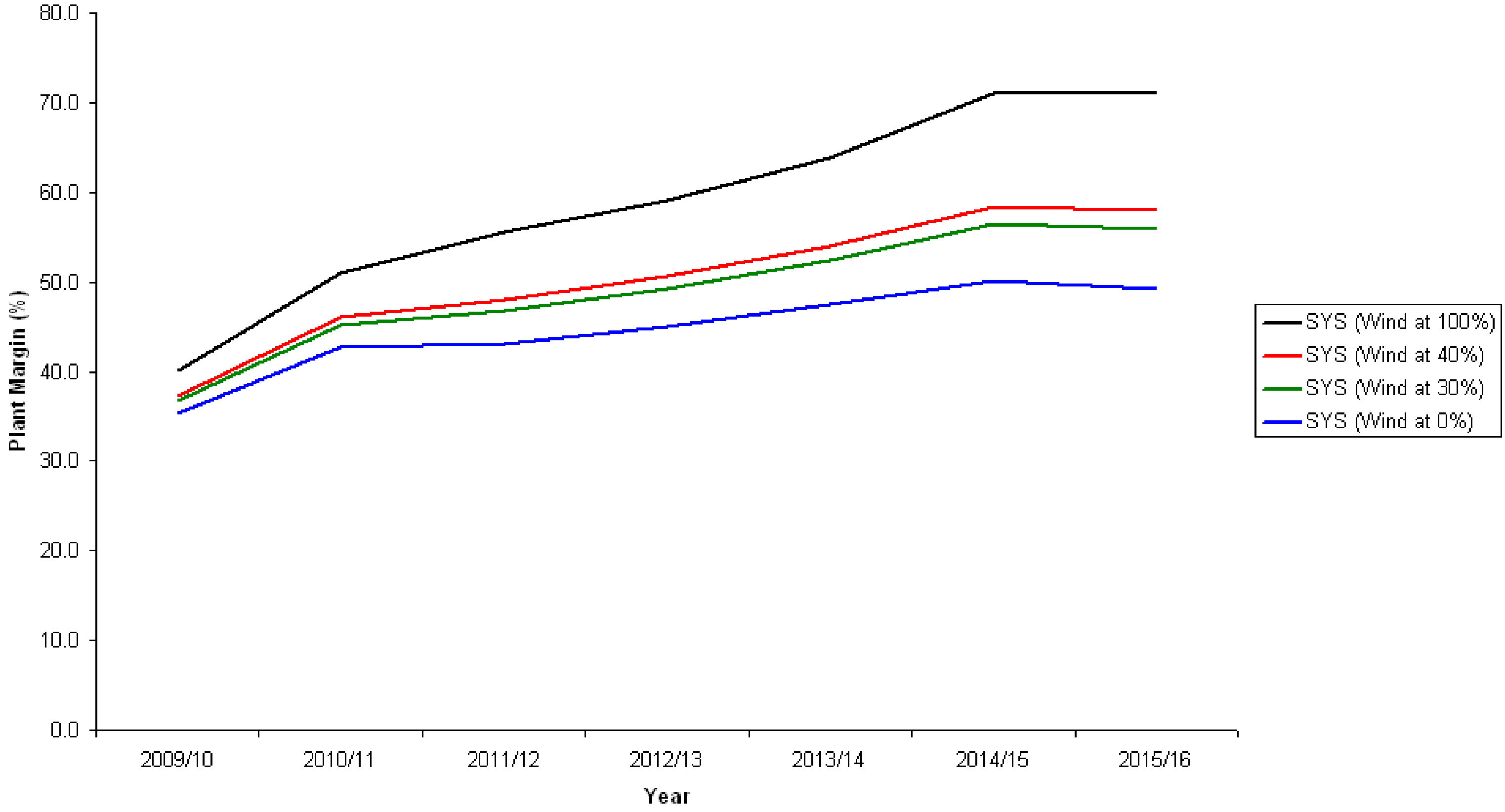


Figure E.6 - Plant Margins for Various Wind Generation Availability Assumptions (relative to SYS Background)



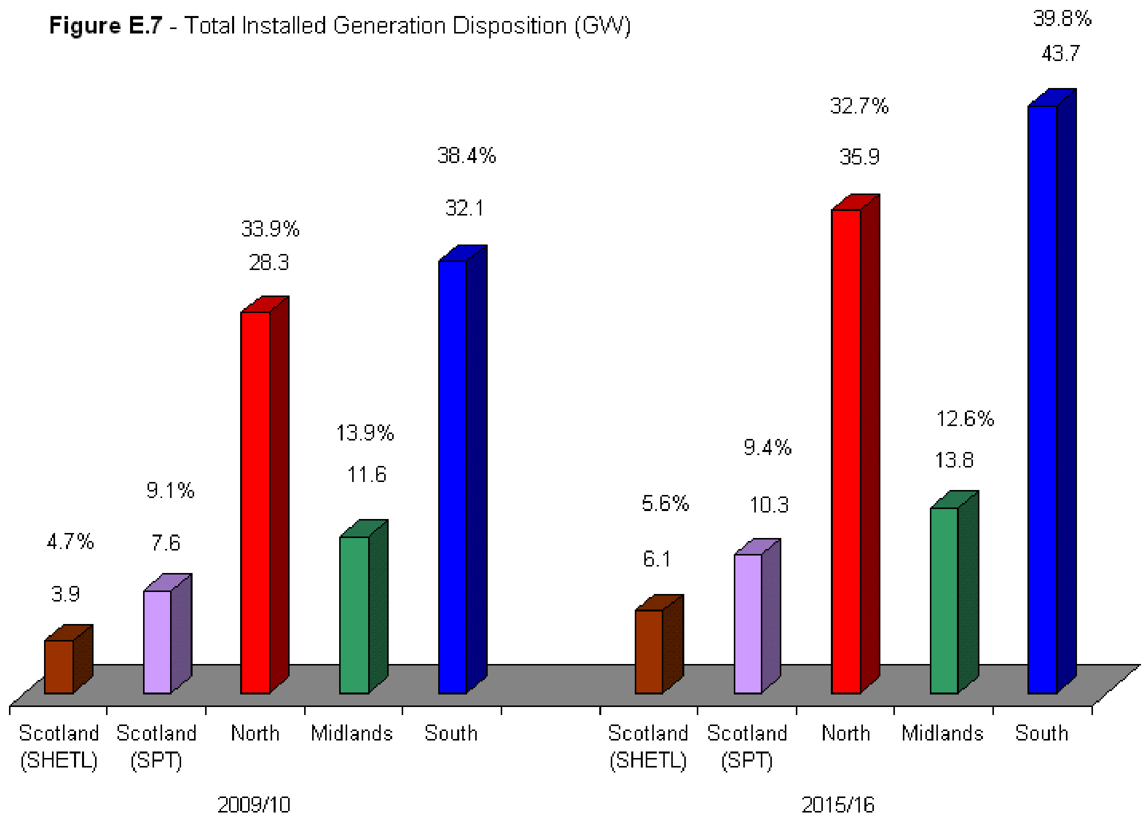


Figure E.7 - Total Installed Generation Disposition (GW)
4.7%
3.9
9.1%
7.6
33.9%
28.3
13.9%
11.6
38.4%
32.1
5.6%
6.1
9.4%
10.3
32.7%
35.9
12.6%
13.8
39.8%
43.7
Scotland (SHETL)
Scotland (SPT)
North
Midlands
South
Scotland (SHETL)
Scotland (SPT)
North
Midlands
South
2009/10
2015/16

Figure E.8 - GB Zonal Plant/Demand Balance - Installed Generation

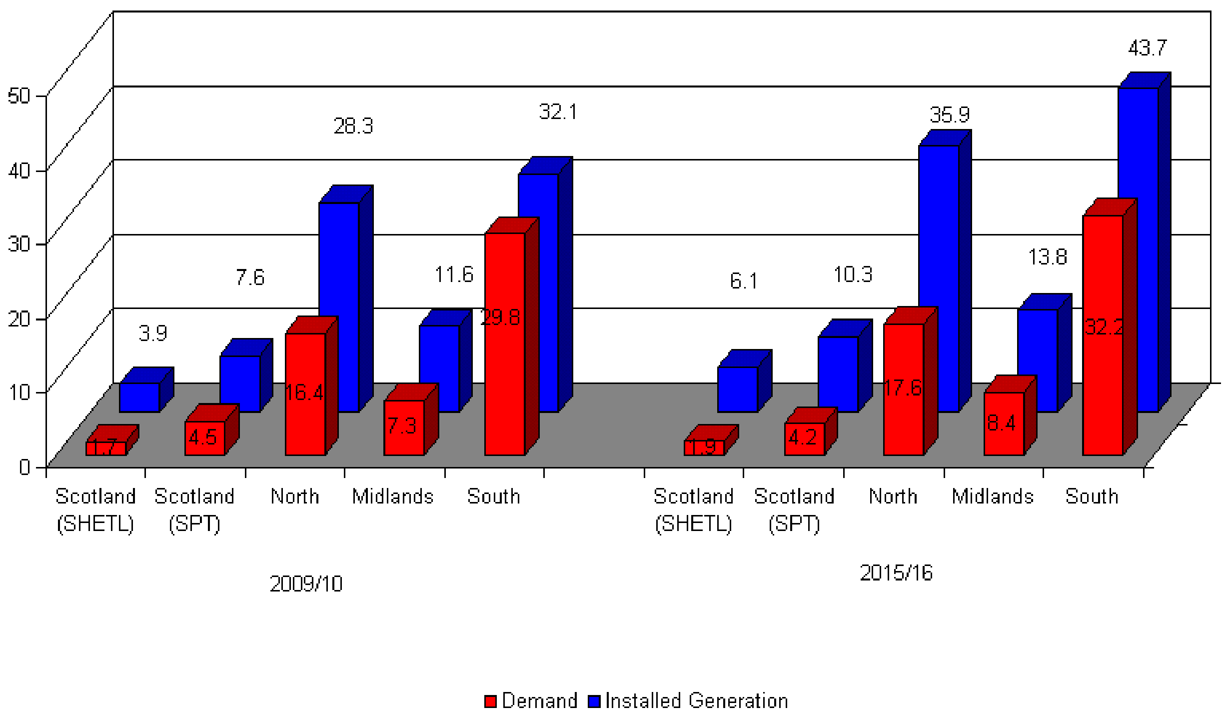
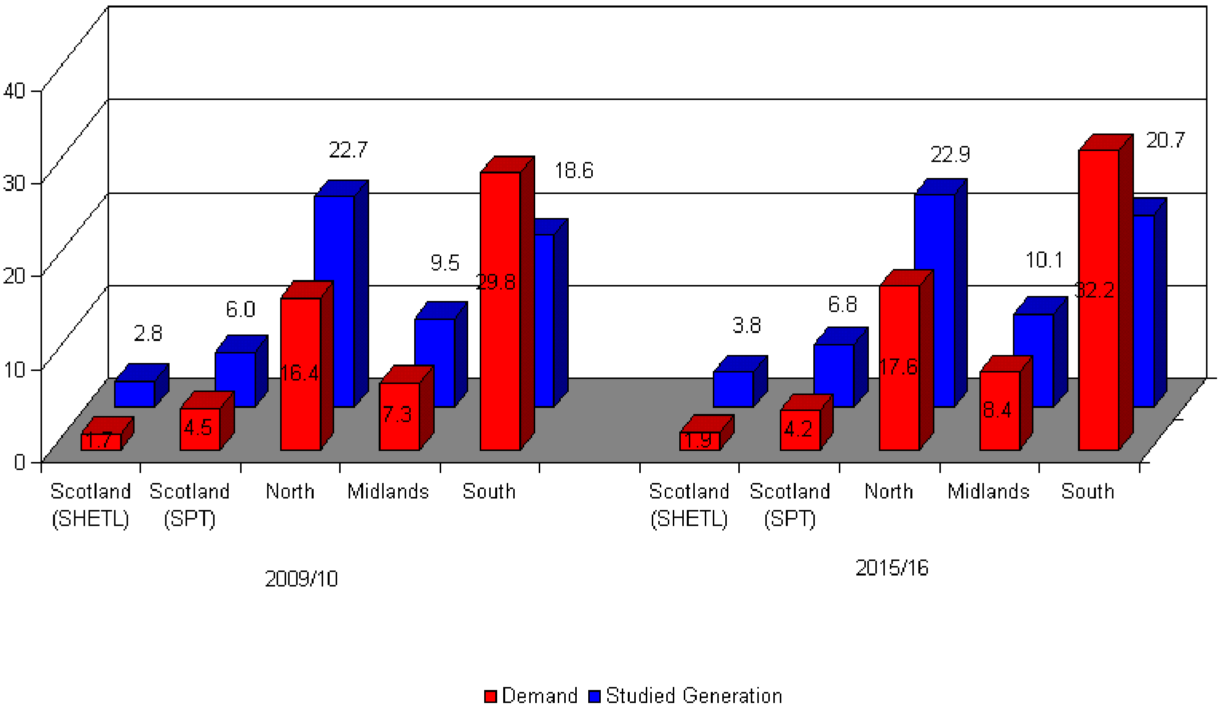


Figure E.9 - GB Zonal Plant/Demand Balance - Studied Generation



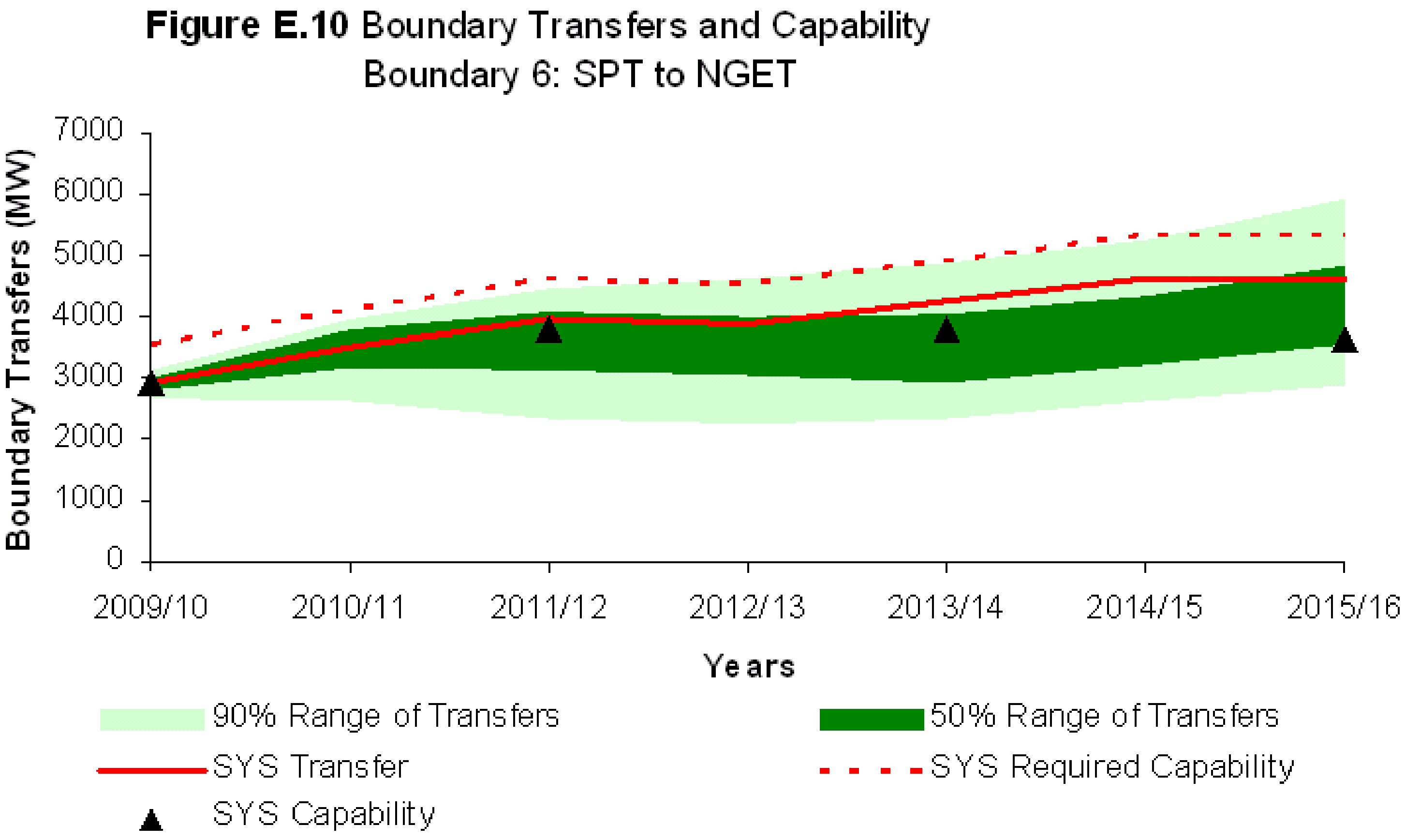


Figure E.10 Boundary Transfers and Capability
Boundary 6: SPT to NGET
Boundary Transfers (MW)
7000
6000
5000
4000
3000
2000
1000
0
2009/10
2010/11
2011/12
2012/13
2013/14
2014/15
2015/16
Years
90% Range of Transfers
50% Range of Transfers
SYS Transfer
SYS Required Capability
SYS Capability

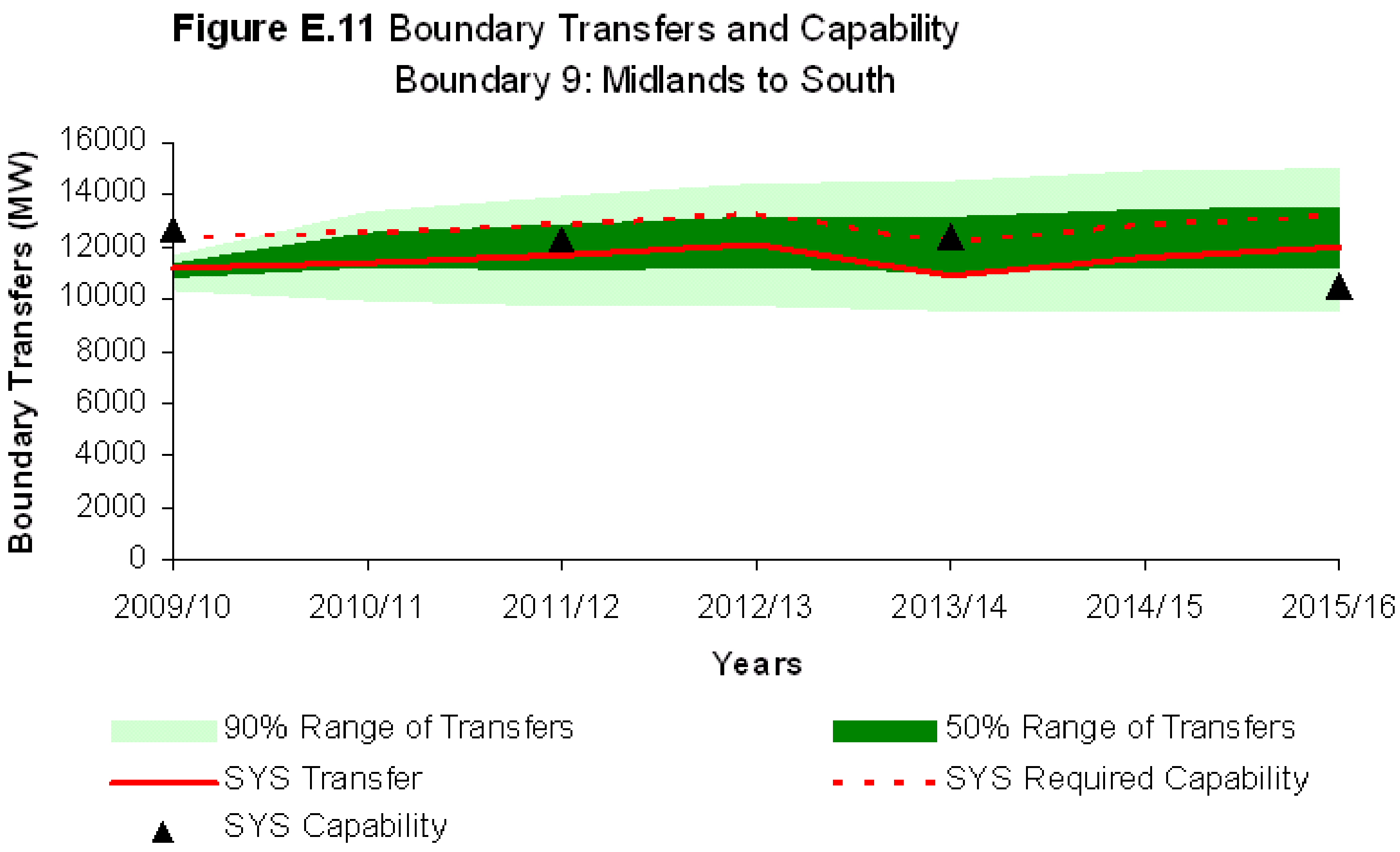
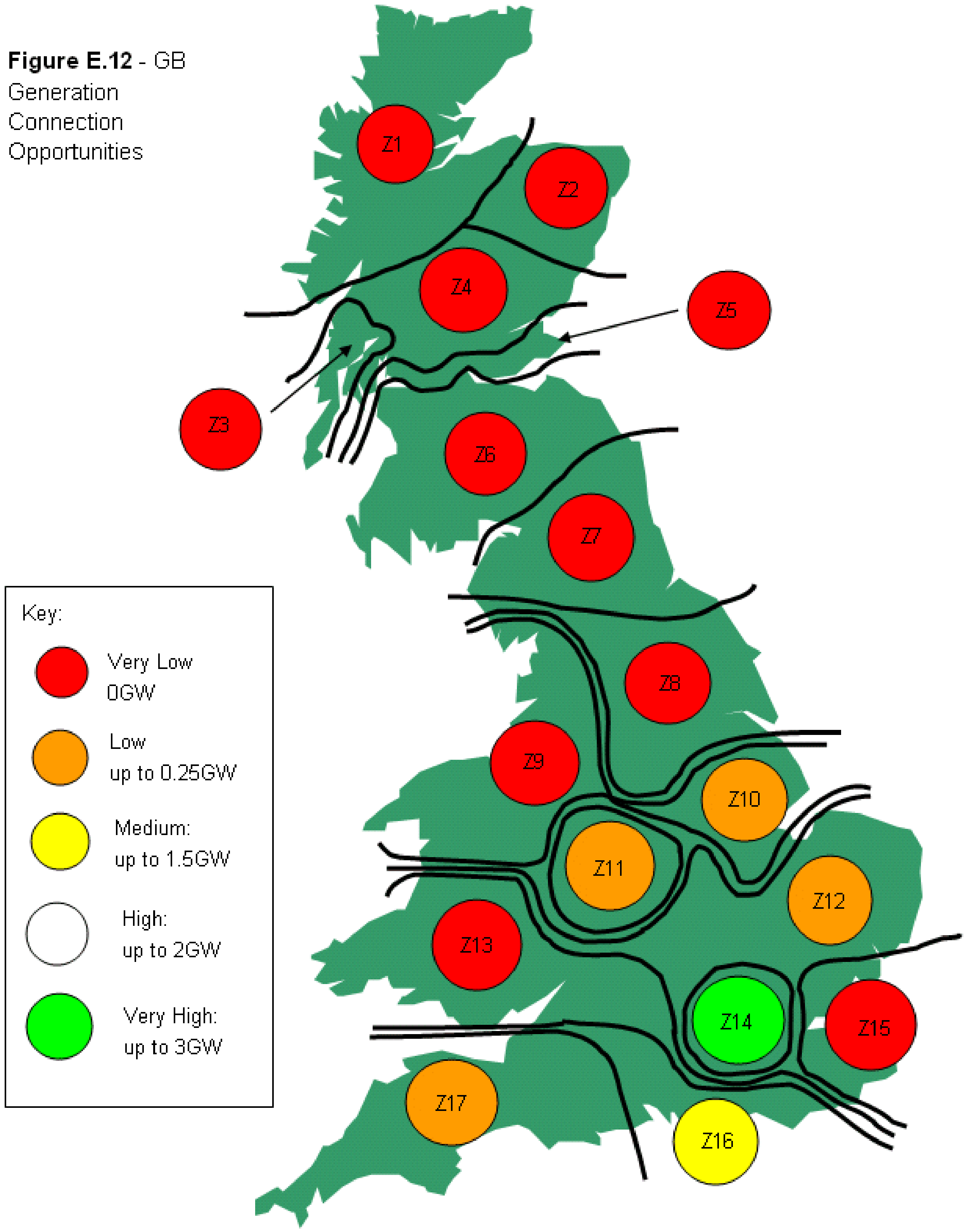


Figure E.11 Boundary Transfers and Capability
Boundary 9: Midlands to South
Boundary Transfers (MW)
16000
14000
12000
10000
8000
6000
4000
2000
0
2009/10
2010/11
2011/12
2012/13
2013/14
2014/15
2015/16
Years
90% Range of Transfers
50% Range of Transfers
SYS Transfer
SYS Required Capability
SYS Capability

Figure E.12 - GB Generation Connection Opportunities



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GB Seven Year Statement
2009

Introduction to Chapter 1

The 2009 Great Britain Seven Year Statement (GB SYS) is the fifth to be published by National Grid Electricity Transmission plc (NGET), acting in its role as Great Britain System Operator (GBSO). National Grid Electricity Transmission plc is a member of the National Grid plc ("National Grid") group of companies.

When the British Electricity Trading Arrangements (BETTA) were introduced on 1 April 2005, National Grid became required to produce a single Seven Year Statement covering the whole of the Great Britain (GB) transmission system (i.e. the GB SYS). The Statement is produced in accordance with the obligations placed on National Grid, acting as GBSO, under the System Operator Standard Licence Condition C11 of National Grid's Transmission Licence. Amongst other things, this condition requires that National Grid publishes a GB SYS on an annual basis and in a form approved by the Authority. The two Scottish transmission licensees, Scottish Power Transmission Ltd ("SPT") and Scottish Hydro Electric Transmission Ltd ("SHETL"), are required to assist National Grid in preparing each GB SYS pursuant to their licence obligations.

A key purpose of the GB SYS is to assist existing and prospective new Users of the GB transmission system, whether generators or suppliers of electricity, in assessing the opportunities available to them for making new or additional use of the GB transmission system in the competitive electricity market in Great Britain. Whilst the text in this Statement reflects new terminology, institutional, contractual and other changes relating to BETTA and other subsequent recent developments, the subject matter presented remains much the same as that of each of the previous Statements.

GB SYS Structure

For those readers who are unfamiliar with the current market structure, including the British Electricity Trading Arrangements, **Market Overview** provides a high level summary of these and a number of related issues such as governance, institutional and contractual arrangements.

The chapter entitled **Embedded and Renewable Generation** has been included in recognition of the current and potential future growth in embedded and renewable generation given the government's targets for generation from combined heat and power (CHP) and renewable sources.

The Statement presents a wide range of technical and non-technical information relating to the GB transmission system in a series of chapters and appendices. The subject matters include: projected demand; generation; embedded generation (as mentioned above); plant margins; the characteristics of the existing and planned GB transmission system; its expected performance (including power flows; loading, fault levels and its capability to transfer electricity across the system); opportunities and the electricity market (also mentioned above). As far as possible each chapter is self-contained with appropriate text, tables and figures.

The nomenclature of the table headings reflects the chapter to which each table belongs e.g. **Table 3.4** is the fourth table in the chapter entitled **Generation** . In some cases where a table contains a large amount of material of a general nature or where the figures are particularly large, then those tables and figures have been included in an appendix and referenced with a prefix associated with the relevant appendix e.g. **Figure A.1.1** is included in **Additional Figures** and **Table B.1a** is included in **Data**.

Additional Figures , **Data** , **Power Flows** , **Fault Levels** and **Grid Supply Point Demand Data** present technical information relating to the GB transmission system and its performance in diagrammatic and tabular form. This material is introduced and referenced in the main text.

Confidentiality of Information

Much of the data included in this GB SYS is provided by Users and potential new Users of the GB transmission system other than National Grid and the two Scottish Transmission Licensees. There are certain obligations placed on ourselves (e.g. Clause 6.15 of the Connection and Use of System Code) regarding the use of such data with respect to 'disclosure of commercial interests'.

In view of this, the customer demand and generation information listed in the Statement and used to produce the forecast power flows is generally restricted to that for which an appropriate Bilateral Agreement has been entered into between the relevant Transmission Licensee and the customer. Speculative new projects, potential closure of existing stations or other developments, which may have been discussed with the relevant customer, are not included without the agreement of the customer. In this Statement, present and future customer developments for which appropriate Bilateral Agreements have been entered into are generally referred to as 'transmission contracted'.

Similarly, unless otherwise stated, the transmission network presented includes developments needed for the "transmission contracted" demand and generation projects and excludes transmission works that may be needed to accommodate prospective (i.e. not as yet the subject of an appropriate Bilateral Agreement) new or modified projects for demand or generation.

It should be noted that some proposed transmission developments included in the background may also be subject to planning consent as may the transmission contracted demand and generation projects.

The GB SYS Background

Unless otherwise stated, the network analyses (e.g. the illustrative power flows, the loading on each part of the GB transmission system and the fault levels) presented in this GB SYS is based on a system background referred to as the "GB SYS Background", which is often shortened to "SYS background". The SYS Background is made up of the following:

(i) Demand Background: The "customer-based" demand forecasts rather than the "NGET based" GB demand forecasts. Both sets of demand forecasts are reported in Electricity Demand;

(ii) Generation Background: Unless otherwise stated the existing generation and that proposed new generation for which an appropriate Bilateral Agreement (i.e. BCA, BEGA or BELLA) is in place. This is detailed in Generation Capacity; and

(iii) Network Background: The existing transmission network and those future transmission developments, which are considered 'firm' in that they are least likely to be varied or cancelled as the needs of the evolving system change. Such transmission developments will include, but will not be restricted to, those schemes, which have been technically and financially sanctioned by the relevant Transmission Owner.

Other schemes, which may not yet be financially sanctioned by the relevant Transmission Owner, but which are nevertheless considered 'firm', may also be included. Such transmission reinforcement schemes would, nevertheless, be associated with "Transmission Contracted" generation projects included in the generation background of (ii) above and may have an appropriate Transmission Owners Construction Agreement (TOCA) and Transmission Owners Reinforcement Instruction (TORI) in place.

Transmission network information is detailed in GB transmission system.

Please note that the terminology used in the above background descriptions is explained in the Glossary.

The "SYS background" is internally consistent. For example, the transmission background of item (iii) above includes all transmission connection developments cited in the relevant connection agreement as being necessary to connect the generation contained in the background of item (ii) above. The "SYS background" does not include any transmission development that may be needed to accommodate prospective projects of new generation or demand, which do not have an appropriate Bilateral Agreement in place on the Data Freeze Date of 31 December 2008, and which are therefore not reported under item (ii) above. The connection dates used, reflect the contracted position.

It is recognised that the above "SYS background" does not necessarily represent the most likely outturn. For example, it is reasonable to suppose that new applications for power station connections will be received, some power stations will close and some contracts for generation projects may be modified or terminated. This may lead to the need to vary the planned future development of the transmission system to meet changing system requirements. Whilst the main body of this Statement is based on the "SYS background", future uncertainties and their effect on system performance, the need for transmission reinforcement and resultant opportunities have also been considered in the relevant chapters.

In view of the abovementioned uncertainty associated with the need for future developments, the timing of construction of reinforcements to the Main Interconnected Transmission System (MITS) is managed such that investments are made to well defined requirements. Accordingly, in some cases, reinforcement of the MITS may be deferred to the last moment to avoid the risk of undertaking investments which may, in the event, turn out to be unnecessary. In view of this, the "SYS background" may not necessarily contain all the MITS reinforcement schemes required for compliance with the Licence Standard. However, this Statement does include an indicative list of future reinforcement schemes, which could be used where necessary to maintain compliance with the Licence Standard.

Further Information

The information provided in this Statement will, amongst other things, enable existing customers and potential new customers to identify general opportunities for new, continued and further use of the GB transmission system. When a customer is considering a development at a specific site, certain additional technical information in relation to that site may be required which is of a level of detail that is inappropriate to include in a document of this nature.

In such circumstances the customer may contact the appropriate Transmission Licensee, initially the relevant technical contact (address in Contact Us), who will be pleased to arrange a confidential discussion, and the provision of such additional information relevant to the site under consideration as the customer may reasonably require.

Customers wishing to make an Application for an appropriate Bilateral Agreement to the Connection and Use of System Code (CUSC) and wishing to discuss the possible terms of such an agreement or obtain an application pack, should initially contact the relevant commercial contact (address in Contact Us).

Other useful addresses together with a list of documents produced by ourselves and others which readers may find helpful, can be found in Contact Us and References.

Quarterly Updates

The main Statement is supplemented by a set of Updates. The first Update to this 2009 GB SYS will be issued shortly after publication of this main Statement and will report on changes notified since the data freeze date. As in previous years, further Updates will be issued on a regular basis (approximately three month intervals). Quarterly Updates provide a brief summary of the key changes since the main Statement was produced. No new simulations are carried out for the Updates but an estimate is made of the effect of the changes on the various issues covered by the Statement.

Data Freeze Date

The 'Data Freeze Date' for all information included in this Statement reflects, unless otherwise stated, the extant position on **31 December 2008**. Subsequent developments are reported in the Quarterly Updates.

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GB Seven Year Statement
2009

Introduction to Chapter 2

This chapter presents forecasts of electricity demand to be met from the GB transmission system. The main forecasts are based on information submitted by Customers (transmission system 'Users') who take, or propose to take, electricity from the high voltage system. These 'User' based forecasts, together with the generation and transmission backgrounds described in the chapters on **Generation** and **GB Transmission System** respectively, form the basis of the SYS background upon which most of the studies presented in this Statement are based.

NGET's own 'base' forecast of electricity demand to be met via the GB transmission system is also presented, along with alternative 'high' and 'low' scenario forecasts. Unlike the 'User'-based forecasts, which include details of individual Grid Supply Point demands, the NGET forecasts are overall projections for Great Britain. These forecasts are included as supplementary information and reflect our views on possible outcomes based on specific assumptions, which are reported.

In general, the level and location of generation remains the major factor in determining the need for transmission system reinforcement. However, in some areas (e.g. importing areas), demand can exert the greater influence and as such, there is an increasing need for accurate demand forecasts in terms of both level and location.

Additional explanatory information is also given, including an explanation of the sources of the customer demand data, how it is processed and the terminology used.

'User' Based Forecasts

ACS Peak GB Demand

This chapter focuses on the demand defined in the Glossary of Terms as "ACS Peak GB Demand" and discussed in **Demand terminology**. Accordingly, the "ACS Peak GB Demand" includes, amongst other things, distribution and transmission losses, station demand (i.e. station auxiliary demand supplied through the station transformers) and exports to External Systems.

Row 1 of **Table 2.1** gives the 'Unrestricted' peak demand (as defined above) on the GB transmission system in ACS (average cold spell) conditions based on the projections made by the system 'Users'. This demand increases from the provisionally estimated outturn of 59.0 GW in 2008/09 to 64.1 GW by 2015/16, which represents a growth of 1.1% per annum. An explanation of the ACS correction procedure is given in the **Supplementary Demand Information** section of this chapter. The forecasts are in respect of the time of the simultaneous peak demand on the GB transmission system and accordingly take account of any diversity between the individual peak demands on each of the systems of the three Transmission Licensees (i.e. NGET, SPT and SHETL). As a point of interest, no pumping demand at pumped storage stations is assumed to occur at peak times.

Peak demands represent the highest demands on the GB transmission system to be met by Large Power Stations (directly connected or embedded), Medium and Small Power Stations which are directly connected to the GB Transmission System and by electricity imported directly into the GB transmission system from External Systems. They are therefore net of any allowance the User makes in his forecasts for the output of Medium Power Stations, Small Power Stations or Customer Generation embedded within distribution networks, and imports across embedded External Interconnections to these systems (i.e. Isle of Man). The allowances made by the Users for such embedded generation is discussed in **Embedded and Renewable Generation**; Tables 4.1 and 4.2 are of particular relevance.

As mentioned above, both the distribution and transmission system losses are included in the demand forecasts, as are exports across External Interconnections to External Systems. The distribution losses are included as part of the Users' submissions and estimated transmission losses are made at the time the forecast is formulated. Pragmatic assumptions, based on historical evidence and market intelligence, are made with respect to exports to External Systems. For instance, while the Moyle interconnector between Scotland and Northern Ireland is capable of a 500MW export, a 250 MW export is assumed for the time of the GB peak demand.

Since the introduction of the British Electricity Trading and Transmission Arrangements (BETTA) in 2005, Seven year Statements have been extended to encompass the GB transmission system. In addition to widening demand forecasts to include Scotland, the ACS correction methodology was also updated. An explanation of the ACS correction procedure is given in the **Supplementary Demand Information** section of this chapter.

One particular change to the ACS methodology was made in order to address the significant fall-off experienced in the amounts of demand control being notified by suppliers under the Grid Code. This was making it increasingly difficult to derive realistic historical 'unrestricted' demands, i.e. actual metered ('restricted') demands plus notified demand control, on which to base the ACS correction. As a result, ACS demands are now calculated from historical 'restricted' rather than 'unrestricted' demands. (For the avoidance of doubt, 'restricted' demand is the level of demand after taking into account any demand control, i.e. it represents the actual metered outturn, whereas 'unrestricted' demand takes no account of the impact of any demand control).

Infrastructure planning for the transmission system continues to be based on ACS ‘unrestricted’ demands – a prudent approach to transmission planning made on the basis that demand control cannot be fully relied upon to be enacted at peak times. Historical ‘unrestricted’ ACS peak demands are now derived by analysing winter weekday evening peaks to estimate the total amount of customer demand control (both notified and un-notified) in force at such times. The resulting amounts, approximately 1 GW, are similar to the levels of load management being notified during the 1990s. Adding the load management estimates onto the historical ‘restricted’ ACS peak outturns yields ‘unrestricted’ demands which form the basis of the ACS outturns and forecasts given in this Statement.

As a cautionary note, other related documents may refer to ‘restricted’ rather than ‘unrestricted’ demands, a case in point being National Grid’s ‘Winter Outlook Report’. Naturally, therefore, care should be exercised when making comparisons between demand forecasts on different bases.

As previously mentioned, station demands (i.e. power station demand supplied via the station transformers directly from the GB transmission system) are included in the main forecast ACS peak GB demand presented in row 1 of **Table 2.1**.

However, **Table 2.1** also presents (in rows 3 and 5) the ‘User’ demand forecasts excluding power station demand. This recognises that Transmission Entry Capacity (TEC), which is a key term used to describe power station output, is used extensively in other analyses presented elsewhere in this Statement (e.g. power system analyses and plant margin evaluation). By definition, TEC is net of station demand and accordingly, ACS Peak GB Demand excluding station demand should be used where relevant to avoid it being double-counted.

In addition, row 5 of **Table 2.1** presents the 'User' demand forecasts excluding exports across the Moyle interconnector between Scotland and Northern Ireland as well as excluding power station demand. This forecast is compatible with the generation ranking order of **Table 7.1** , which treats exports to Northern Ireland as negative generation. **Table 7.1** is presented in **GB Transmission System Performance**.

Figure 2.1 shows recent ACS peak outturns and the current 'User' forecasts of ACS peak demand on the GB transmission system given in row 1 of **Table 2.1**.

Figure 2.1

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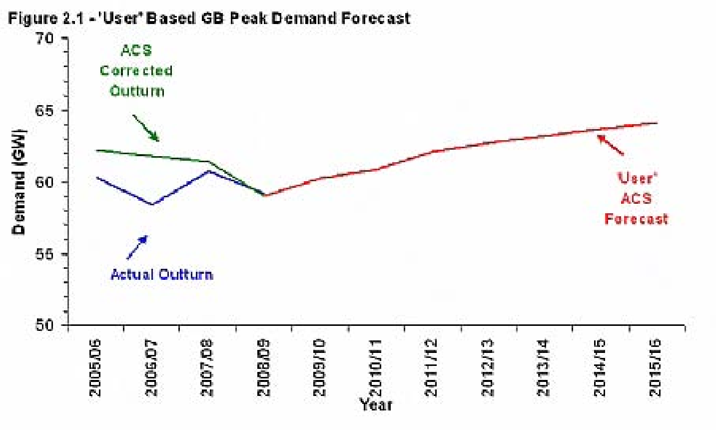

It is explained under the **Customer Demand Data** section that, while the local peak demand is used for Grid Supply Point planning, the demand at the time of the GB system peak is used for infrastructure planning purposes. That section also explains that transmission losses are added to the Users’ demand submissions, after which they are adjusted such that the aggregate of 'User' demand projections for the base year (2008/09) is scaled to the provisional or, if known, final ACS corrected outturn for the winter. The resulting adjustment factor is applied to subsequent years, thus retaining customers’ forecast aggregate annual growth rates. These forecasts are amended when necessary in SYS Quarterly Updates to align with final base year ACS outturns.

Demand on the Grid Supply Points (GSPs)

Grid Supply Points (GSPs) are the points of connection between the GB transmission system and the distribution networks and/or Large Power Stations. The times of individual GSP peak demands can vary from GSP to GSP and as such may not coincide with the time (or date) of the GB system peak. In Appendix E, tables E.1.1 to E.1.7 list the ‘User’-based forecasts of maximum demand for each GSP, firstly in respect of the time of the GSP peak and secondly in respect of the projected time of the GB system peak. These demands are measured at the GSP and accordingly include distribution losses but, unlike the demands given in **Table 2.1**, they naturally do not include transmission losses.

The final column in **Table E.1.1** of the above series gives DCLF Node information. This has been included to enable Users to identify the HV Direct Current Load Flow (DCLF) transport model node at which LV demand is mapped for the purpose of calculating Transmission Network Use of System (TNUoS) tariffs (please refer to **Use of System Tariff Zones**) and producing the Condition 5 information paper which forecasts the future path of the locational element of the TNUoS tariffs. The additional column is included for information purposes, but it should be noted that the GB Peak figures included in the table will not necessarily exactly match those demand figures contained in the DCLF transport model as adjustments to the data are made to allow for station demand and generation is treated as negative demand. Also in Appendix E, the series of tables E.2.1 to E.2.7 provide GSP information at the projected time of the minimum GB system demand.

For grid supply point planning, demand at each GSP's peak is used, together with appropriate allowances for embedded Large Power Stations, in accordance with the Licence Standard. An allowance for generation by Medium and Small Power Stations and imports across embedded External Interconnections is already made in the customers’ demand projections. For completeness, Tables E.1 and E.2 also list Large Power Stations connected to GSPs or embedded in the distribution networks behind GSPs, together with demand power factors.

Recent Growth in Peak Demand

Figure 2.1 shows recent GB actual and ACS peak demands along with the latest 'User'-based projections of ACS peak demand on the GB transmission system. Correcting historical peak demands to ACS conditions enables underlying peak demand patterns and trends to be more readily observed.

Many factors can influence the level of peak demand met by the transmission system. These include the weather; economic activity; energy prices; energy efficiency/conservation; customer demand management; competition from other fuels; take up of self-generation; supplies taken from generation embedded within distribution networks and the level of interconnector exports.

For many of the above factors, the effects are generally small over time and may have little impact on the year-on-year changes in transmission system demand. Evidently, this year, we have seen the impact of an economic downturn. Another significant factor is the weather, which can cause wide variations in demand, especially peak demand, from one year to the next.

Actual GB peak demand in the winter of 2008/09 at 59.2 GW was 1.5 GW lower than in the previous winter. A major factor in the significant peak demand drop seen between 2007/08 and 2008/09 was the economic downturn. The ACS correction procedure, which is outlined in **Supplementary Demand Information**, eliminates the weather effects and gives a better indication of the underlying pattern of annual peak demand (see **Table 2.4** and **Figure 2.1**).

Correcting winter weekday peak demands in 2008/09 to ACS conditions yields a provisional 'unrestricted' peak of 59.0 GW, which is 2.4 GW lower than previous winter's ACS peak. The main difference of this is the impact of recession in 2008/09, and general energy efficiency measures such as energy saving light bulbs.

The definition of demand used throughout this Statement is explained and discussed in the section on **Demand Terminology** and includes exports to External Systems. Before the commencement of the New Electricity Trading Arrangements (NETA) in March 2001, little power was exported across the External Interconnector with France. However, under NETA and its successor, the British Electricity Trading and Transmission Arrangements (BETTA), the cross-channel link has operated more on a two-way basis, although exports to France do not tend to occur at GB system peak times and imports have still predominated at other times. In addition, since it became operational in 2002, the 500MW Moyle interconnector link between Scotland and Northern Ireland has been used almost solely to export power to the province. A similar pattern is likely when the two planned interconnectors between North Wales and the Irish Republic become operational. Both interconnectors have a contracted start date of 2011/12.

Demand Profiles

Figure 2.2 ppresents daily demand profiles for the days of maximum and minimum demand on the GB transmission system in 2008/09 and for days of typical winter and summer weekday demand. Please note that these demands are shown exclusive of station transformer, pumping demand and interconnector exports.

Figure 2.2

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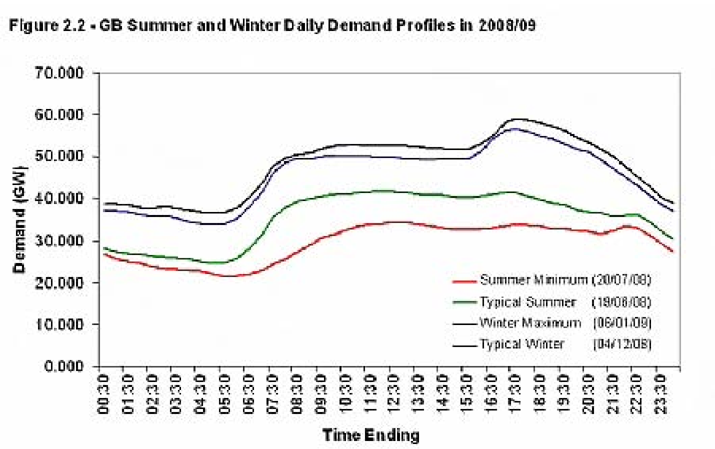

Key points of interest are: -

(i) Maximum & Typical Winter Profiles (Weekday)

000:00h - 03:00h: Operation of time-switched and radio tele-switched storage heating & water heating equipment.
06:30h - 09:00h: Build-up to start of working day.
09:00h - 16:00h: Plateau reflecting the working day (primarily commercial & industrial demand).
16:30h - 17:30h: Rise to peak due to lighting load and increased domestic demand outweighing fall-off in commercial and industrial demand.

(ii) Typical Summer Profile (Weekday)

As (i) above without effects of storage heating demand and with the later onset of evening lighting load.

(iii) Minimum Summer Profile (Sunday)

As (ii) above with increased lunchtime cooking demand.

Whilst **Figure 2.2** shows how demand varies through the day in summer and winter, **Figure 2.3** plots weekly maximum and minimum demands in 2008/09 to indicate how demand varies over the year. As with **Figure 2.2** , the demands shown in **Figure 2.3** are exclusive of station and pumping demand and interconnector exports.

Figure 2.3

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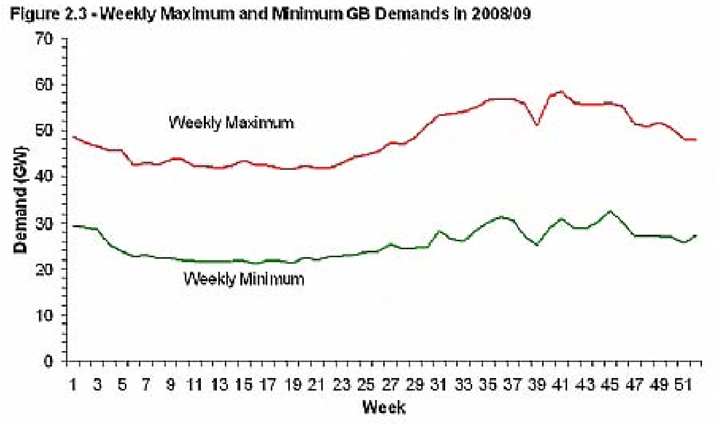

Figure 2.4 shows the GB annual load duration curve for 2008/09. Based on demand data for every half hour of the year, it shows the percentage of time in the year against the proportion of the year's peak. For example, demand exceeded 50% of the annual peak for more than 83% of the time.

Figure 2.4

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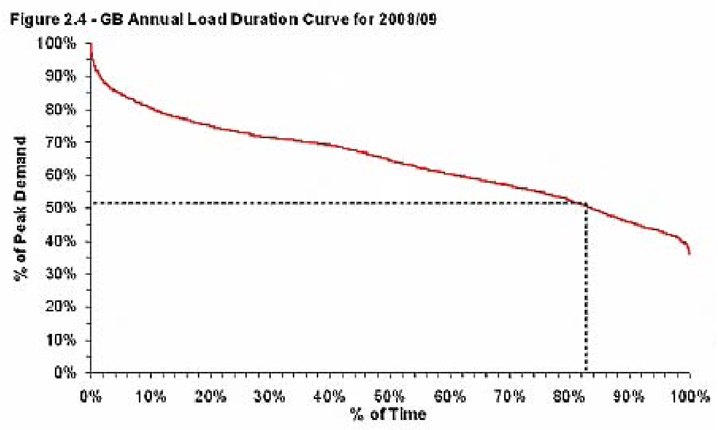

National Grid Forecasts

Background

'User' based peak demand forecasts presented in this Statement are obtained from the aggregation of 'User' submissions (see **Table 2.1**) and these forecasts form part of the SYS background upon which most of the studies presented in this Statement are based. For comparison, NGET has provided its own 'base', 'high' and 'low' demand scenarios. The 'User'-based forecast is considerably higher than NGET's 'base' forecast due to the severe impact of the economic recession which was not foreseen when 'User' forecasts were submitted in June 2008.

For the 'high' and 'low' demand scenarios, combinations of favourable and adverse developments are assumed which yield high and low transmission system demands. For example, in the low scenario better progress towards the government's 2010 targets and beyond for combined heat and power and renewables is assumed, resulting in stronger growth in embedded generation. In contrast, in the high demand scenario, it has a much slower take-up of such schemes and hence the level of embedded generation is lower. These assumptions, along with variations for other factors such as economic growth, result in a fairly wide range of outcomes for transmission system demand.

When compared with NGET's 'base' projections, the 'User' based forecasts show stronger growth; particularly over the next couple of years (illustrated in **Figure 2.5**). In submitting their forecasts, 'Users' are not required to provide information on their background assumptions but possible reasons for the transmission system demand differences include alternative views on factors such as economic prospects, levels of energy efficieny and the growth of demand met by embedded generation.

Figure 2.5

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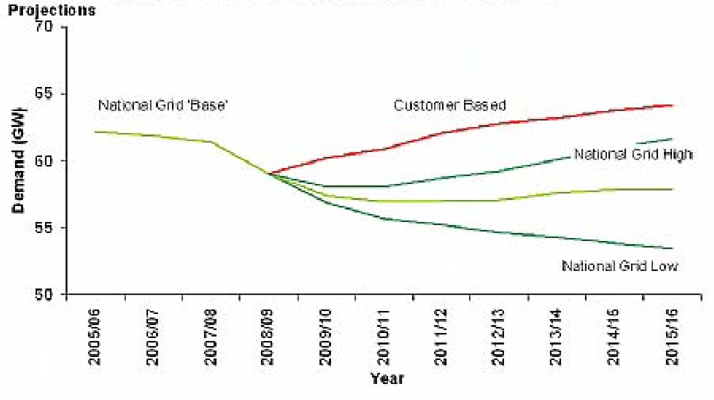
Figure 2.5 - Comparison of Customer-Based Forecast and National Grid Projections



Details of NGET's peak demand and electricity requirements projections and the main economic assumptions underlying them are given in **Table 2.3** and **Table 2.4**. (Please note that the central economic forecasts on which they are based have been provided by Experian Business Strategies).

National Grid 'Base' Forecast

The economy is an important attribute to National Grid's demand forecasts. In 2008, GDP growth was 0.7%, which is the slowest growth since 1992. GDP is expected to contract by 3.7% in 2009, which would be the lowest annual growth seen since 1946. Consumers' confidence has been affected by the 'credit crunch'.

Economic recovery is expected to be slow, with only 0.2% growth forecast in 2010, and historical trend rates of between 2% and 2.5% p.a not forecast until 2012. However, consumer spending is expected to fall in 2009 and 2010 because of the impact of ongoing factors such as low consumer confidence, depressed incomes, rising unemployment and low savings.

With the effect of the recession and increasing energy efficiency measures, total GB annual electricity requirements is projected to continue to fall until 2014/15. Increasing end user demand is offset by expected growth in embedded generation, thus no growth in transmission electricity demand is expected over the period 2009/10 to 2015/16.

As part of its Climate Change strategy for achieving environmental emissions targets, the government set objectives for combined heat and power (CHP) and renewable generation. For CHP, the target was for at least 10GW of electrical CHP capacity by 2010. However, the commencement of the new electricity trading arrangements (NETA) in 2001 had an adverse impact on CHP's fortunes, with the balancing mechanism making it difficult for surplus output from CHP plant to compete in the new market place. As a result many potential developers either abandoned or postponed planned CHP schemes. Over the period of this forecast, a modest recovery from the near moratorium of recent years is assumed for CHP, with electrical capacity reaching 8GW in 2010/11, mainly as a result of two large CHP power stations, Immingham (Stage 2) and Isle of Grain, directly connecting to the transmission network by that year.

The 2010 goal set for renewables was for 10.4% of electricity consumption to be sourced from such generation. To assist with achieving this, the Renewables Obligation (RO) requires increasing proportions of electricity sold each year by licensed suppliers to be sourced from qualifying renewable fuels. In 2007/08, generation from such fuels accounted for 5% of electricity sales, up from 4.4% in the previous year, but below the 7.9% level set for 2007/08.
The EU climate packages sets the goal of increasing renewable energy's share of the market to 20% for 2020, which translates to 15% of total UK energy. This equates to approximately 35% of electricity from renewable sources. This clearly signifies more renewable generation needs to be in place.

As with CHP, the operation of some renewable generation was adversely affected by NETA. However, the NGET 'base' forecast assumes that the ongoing obligation on suppliers to source increasing amounts of electricity from renewable sources will see continued growth in such generation, particularly wind, with the current forecast yielding 7.8% of consumption being met from qualifying renewables in 2010/11.

New CHP and renewable generating capacity, which is embedded within distribution networks, if utilised, can reduce the growth in peak demand seen on the transmission system. In the 'base' forecasts, peak demand is projected to increase by 0.1% p.a., compared with 0.7% p.a. growth projected for overall electricity use by end-users. The difference can be deemed to be offset by embedded generation.

Since it became operational, the 500 MW External Interconnector between Scotland and Northern Ireland has been used almost solely to export power to the province. The 'base' forecast assumes exports of 250 MW across it at peak times, with up to 1 TWh projected annually. In addition, the "East/West" interconnectors between Wales and the Irish Republic are expected to be exporting 437.5 MW at peak and up to 1.3 TWh per annum.

With regard to the External Interconnector between England and France, no exports are projected for GB system peak times and over the duration of this forecast, the interconnector is assumed to continue to be primarily utilised to import power from France, with up to 2 TWh per annum projected for exports.

In summary, electricity usage by end-users is projected to increase by 0.7% p.a. Annual electricity requirements on the GB transmission system was 338 TWh in 2008/09 and the 'base' forecast shows no growth between 2009/10 to 2015/16 at 326 TWh. ACS 'unrestricted' peak demand was 59 GW, with the forecast showing minimal growth from 57.4 GW in 2009/10 to 57.8 GW in 2015/16.

Throughout the period covered by this year's forecast, the User-based forecast is more optimistic than National Grid's 'Base' forecast, and throughout the years, it is higher than National Grid's High growth scenario projections. In the past, the User-based forecasts have tended to underestimate the likely impact of embedded generation on system demand, which results in higher demand forecasts. Furthermore, the User-based forecasts were submitted last June based on demand seen in 2007/08. The National Grid forecasts benefit from being based on demand seen in 2008/09, when peak demand fell against the background of an economic downturn.

National Grid High Growth Scenario

This upside scenario is based on more optimistic assumptions about factors affecting transmission system electricity demand growth over the medium term. A main driver is faster economic growth, with GDP growth averaging 1.8% per annum (see **Table 2.4**). This results in greater use of energy, with end-users usage growth averaging 1.4% p.a. With slow rates of take-up assumed for both CHP and renewable generation embedded within distribution networks, the annual electricity requirements on the GB transmission system are expected to rise by 0.7% per annum, from 330 TWh in 2009/10 to 347 TWh in 2015/16. ACS peak demand increases from 58.1 GW to 61.6 GW over the same period, with growth of 0.9% per annum.

National Grid Low Growth Scenario

In this downside scenario, economic growth is slower (see **Table 2.4**), with GDP expanding by 0.1% per annum to 2015/16. A particularly high profile is assumed for environmental issues, with energy efficiency schemes for domestic and business customers heavily promoted, bringing good progress towards the environmental targets set for 2010 for CHP and renewable generation. Overall, end-users usage, in this scenario falls by 0.1% p.a. However, the effects of significant embedded CHP and renewables growth result in falling demand on the transmission system, with annual requirements on the GB transmission system to decline by 1.1% per annum from 322 TWh in 2009/10 to 298 TWh in 2015/16. ACS peak demand similarly declines by 0.8% p.a., from 56.8 GW to 53.4 GW over the same period.

Supplementary Demand Information

Self-Generation

Customers who load manage in response to high electricity prices and/or triad demand charges can either reduce their production or, if available, fall back on their own generation in order to maintain output. In these circumstances, the form of self-generation used would normally be of a standby nature since other main forms of own generation such as combined heat and power (CHP) would be likely to be already in operation.

As part of its Climate Change Programme to reduce carbon dioxide emissions in 2010 by 20% of their 1990 level, a target of 10GW of electrical CHP capacity was set for 2010 (see **Embedded and Renewable Generation**). Increases in the capacity, and hence use, of CHP and other forms of self-generation, particularly that which is not of a standby type, would be expected to result in commensurate falls in the level of demand met from the transmission system, although this does not necessarily mean a reduction in the system's use. (For example, the location of new self-generation in some areas could result in increased system power flows as a consequence of the displacement of local demand previously met by local generation, leading to the surplus local generation being transported elsewhere by the GB transmission system).

Customer Demand Data

Every 'User' who takes, or expects to take, demand directly from the transmission system via a Grid Supply Point (GSP) is required by the GB Grid Code to provide NGET with demand forecasts with respect to that GSP. These forecasts are required to be submitted by Week 24 (i.e. mid-June) of each year, although updates can be provided after this date.

'Users' who take demand directly from the transmission system are, in the main, the distribution network operators. In addition, some industrial sites are directly connected to the transmission system and most Large Power Stations' own demand is also met from it via their station transformers. The Week 24 forecasts are used for, amongst other things, studying power flows on the transmission system. Accordingly the Week 24 submissions, which are given in respect of each of the seven succeeding financial years, include:

(i) the demand the network operator expects to take from each GSP at the time of the expected system demand peak (the date and time being advised in advance by NGET) - primarily for use in infrastructure planning; and

(ii) the maximum demand the network operator expects to take from each GSP at any time - primarily for use in GSP planning.

In both cases (i) and (ii) above, network operators are required to make allowance for demand met by Medium and Small Power Stations embedded within their networks and for imports across embedded External Interconnections.

When planning the development of the transmission system, account is taken of all Large Power Stations, whether embedded in a distribution network or directly connected to the transmission system.

For power flow studies and other system analyses, total transmission system demand is derived from the Week 24 submissions as follows. Peak demand forecasts at the time of system peak provided by each customer are aggregated and projected transmission losses are added. A correction factor is then applied to the resultant total demand stream which scales the total for the initial year to the provisional (or final, if known) ACS corrected peak demand outturn. Subsequent years are then scaled by the same factor, thus retaining customers' projected annual growth rates. This scaling process was originally formulated with the approval of distribution network operators.

For Grid Supply Point (GSP) planning, demand at each individual GSP's peak is used, together with appropriate allowances for embedded Large Power Stations, in accordance with the Licence Standard. For planning the development of the infrastructure of the main interconnected transmission system, as opposed to specific GSPs, the unrestricted ACS Peak GB Demand forecast is used. Using unrestricted demand for infrastructure planning recognises that demand control cannot be relied upon in the planning time phase. Nevertheless, in the event of a sufficiently high level of certainty being attached to the implementation of demand control we would take demand management into account within our infrastructure planning.

Average Cold Spell (ACS) Correction

Actual outturn peak demands can vary considerably from one year to another depending on the weather and other factors such as economic activity and consumer behaviour. ACS demand correction enables more meaningful comparisons to be made between outturn demands and allows forecasts to be made on a weather base that also conforms to security standard planning requirements.

National peak demand forecasts given in this Statement are based on average cold spell (ACS) weather conditions. These are the combination of weather elements (i.e. temperature, illumination and wind) that give rise to a level of peak demand within a financial year that has a 50% chance of being exceeded as a result of weather variations alone.

Prior to the introduction of the British Electricity Trading and Transmission Arrangements (BETTA) in 2005, ACS outturn peak demands (and forecasts) were based on 'unrestricted' demands. These were derived by adding the load management enacted at peak and notified by suppliers under the Grid Code onto winter weekday outturn peak demands. With BETTA covering the whole GB transmission system, in addition to extending the demand forecasts to incorporate Scotland, the ACS correction methodology was also updated.

One particular change to the methodology was made in order to address the significant fall-off experienced in the amounts of demand control being notified under the Grid Code. The latter made it increasingly difficult to derive realistic historical ‘unrestricted’ demands, i.e. actual metered (‘restricted’) demands plus notified demand control, on which to base the ACS correction, which is now calculated from historical ‘restricted’ instead of ‘unrestricted’ demands. (For the avoidance of doubt, ‘restricted’ demand is the level of demand after taking into account demand control, i.e. it represents the actual metered outturn, whereas ‘unrestricted’ demand makes no allowance for the impact of any demand control).

Although the ACS correction procedure now produces historical ‘restricted’ demands, infrastructure planning for the transmission system continues to be based on ACS ‘unrestricted’ demands. This prudent approach is made on the basis that load management cannot be fully relied upon to be enacted at peak times. ACS ‘unrestricted’ demands are therefore still required and these are obtained by adding estimates of load management obtained from analysis of winter weekday evening peak demands onto the ACS ‘restricted’ peak demands. The resulting ACS ‘unrestricted’ demands outturns provide the platform for producing ‘unrestricted’ demand forecasts.

As a cautionary note, other related documents may publish ‘restricted’ rather than ‘unrestricted’ demands, a case in point being National Grid’s ‘Winter Outlook Report’. Care should therefore be exercised when making comparisons between demand forecasts on different bases.

The specific methodology for identifying ACS demand comprises two main parts. Firstly, a mathematical model estimates demand/weather coefficients from historical ‘metered’ demands (i.e. actual outturn peak demands). The modelling uses recent winters' demands rather than a longer historical period to ensure that the latest demand behaviour is captured as well as to include as much weather variation in the modelling data as possible. Weather and demand data over the GMT period (i.e. late-October to late-March) for weekday peak half hours is modelled to give:

Winter Weekday Darkness Peak Demand is equal to the sum of :-

- A Constant;
- Weather Dependent Demand;
- Demand Management;
- Seasonal Trends (Day, Week, Year); and
- Error Terms.

The weather dependent demand at the darkness peak is a function of :-

- Effective Temperature at 17:00 GMT;
- Effective Temperature squared at 17:00 GMT;
- Effective Illumination at 17:00 GMT; and
- Cooling Power at 17:00 GMT.

The effective temperature (TE) is an average of the current and previous day’s temperature at the time of the winter darkness peak. Cooling power (CP) is an empirical combination of temperature and wind speed, similar to wind chill. Effective illumination (EI) is a function of solar radiation, taking in to account the number and type of cloud layers, visibility and the amount and type of precipitation (although at the time of the darkness peak in mid-winter EI is zero).

In the second part of the ACS correction methodology, the coefficients are used to carry out a simulation analysis of Winter Weekday Darkness Peak Demand (WWDPD) for the last winter. Simulations of the Weather Dependant Demand & Day of the week are fed into the WWDPD model for each Electricity Supply Industry (ESI) week (where weather dependent demand is described above and estimated from TE, EI & CP actuals which are aggregated from regional weather stations collected for the last thirty years).

The peak of the simulated Winter Weekday Darkness Peak Demands for each of 10,000 winter simulations are ordered and the median demand (50th percentile) is identified as the ACS demand (i.e. the level of peak demand that has a 50% chance of being exceeded as a result of weather variation).

Demand Terminology

Demand Definitions

The definition of the term 'ACS Peak GB Demand' given in the Glossary of Terms has been written for the purpose of this Statement. The meaning of the term may differ in some respects in other documentation. **Figure 2.6** provides a generalised illustration of the definition and also aids comparison with other demand terms in current usage.

Figure 2.6

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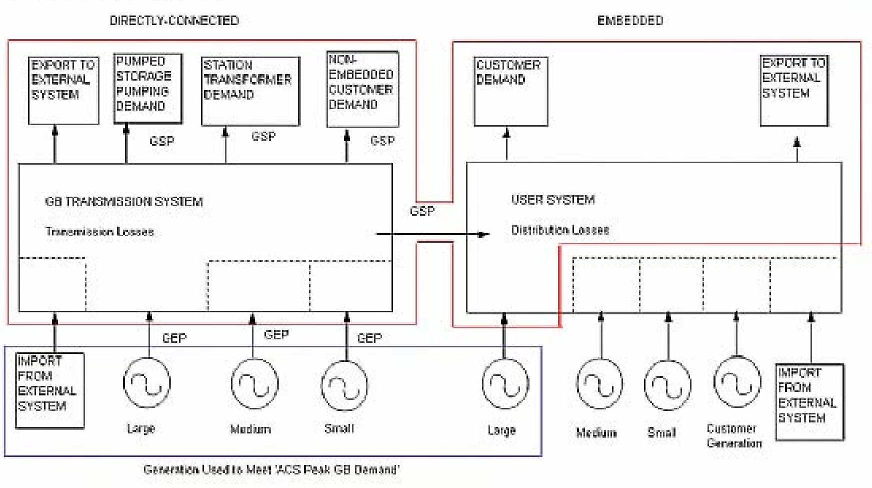
Figure 2.6 - ACS Peak GB Demand



The figure shows the different categories of demand directly connected to the transmission system together with the demands supplied from the distribution networks, which are in turn directly connected to the GB transmission system at Grid Supply Points (GSPs). Transmission and distribution losses are also included.

In **Figure 2.6**, the area within the red border encapsulates those components of demand making up ACS Peak GB Demand, with the generation used to meet ACS Peak GB Demand bordered in blue. This generation comprises; directly connected power stations, whether Large, Medium or Small; embedded Large Power Stations; and imports from External Systems across directly connected Interconnections. Until the winter of 2001/02, exports to France across the Interconnection were exceptional. Since then exports have become more common, although not at times of system peak. All these sources of generation are the subject of **Generation**.

In providing demand forecasts for their Grid Supply Points, the distribution network operators net off their own allowances for the output of embedded Medium and Small Power Stations, Customer Generation and also for the imports across embedded External Interconnections. Customer Generating Plant operates to supply all or part of its own electricity requirements and exports any surplus onto the local distribution network. Embedded generation is the subject of **Embedded and Renewable Generation**.

The SYS definition of ACS Peak GB Demand is in line with the GB Grid Code definition of "GB Transmission System Demand". Please note that in both cases (i.e. the above definition and the GB GC definition) the demand includes exports to external systems, pumped storage pumping demand and station transformer demand. This is unlike the GB GC definition of "GB National Demand", which specifically excludes those three demand categories.

For the duration of this forecast it is assumed that there will be no exports to France at the time of the GB system peak, nor is there likely to be any demand at peak associated with pumped storage. Exports at peak are expected from the SPT system to Northern Ireland via the Moyle interconnector and across the planned 500MW interconnector between North Wales and the Irish Republic, and these exports form part of the "ACS Peak GB Demand". (As a point of interest, the converse also applies, i.e. expected imports from External Systems at times of system peak contribute to supplying demand and are therefore treated as generation).

Figure 2.1 - 'User' Based GB Peak Demand Forecast

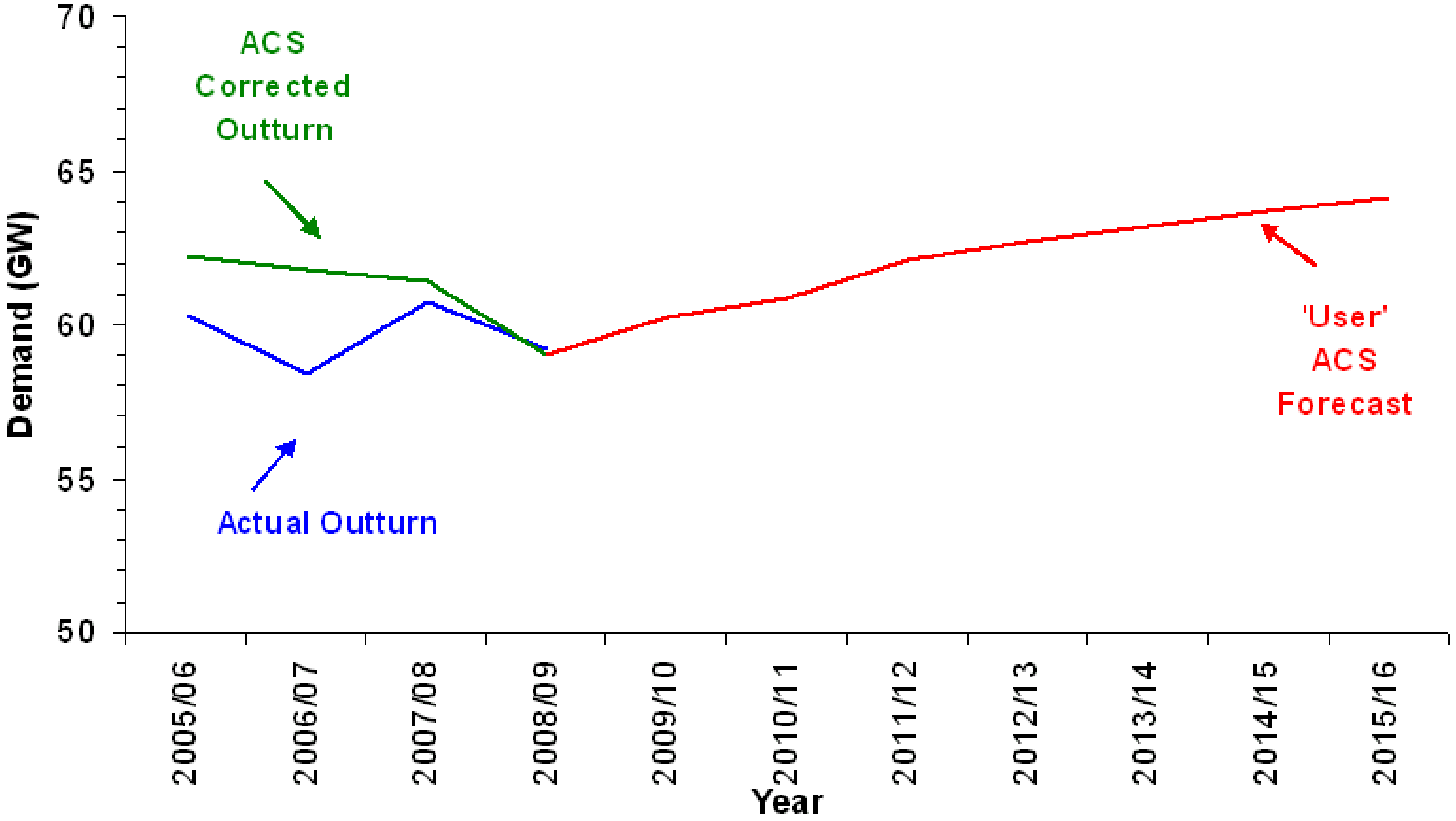


Figure 2.2 - GB Summer and Winter Daily Demand Profiles in 2008/09

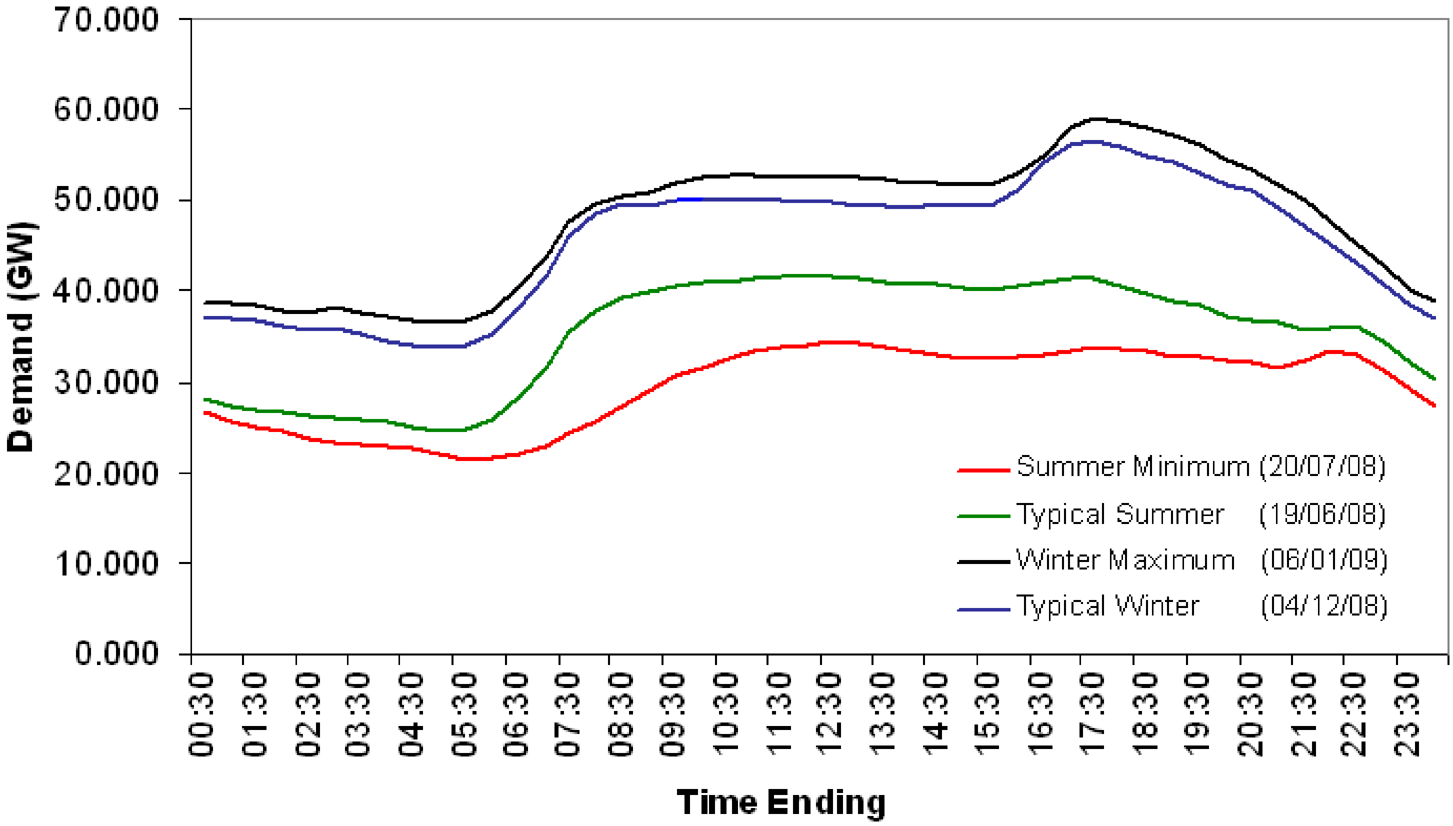


Figure 2.3 - Weekly Maximum and Minimum GB Demands in 2008/09

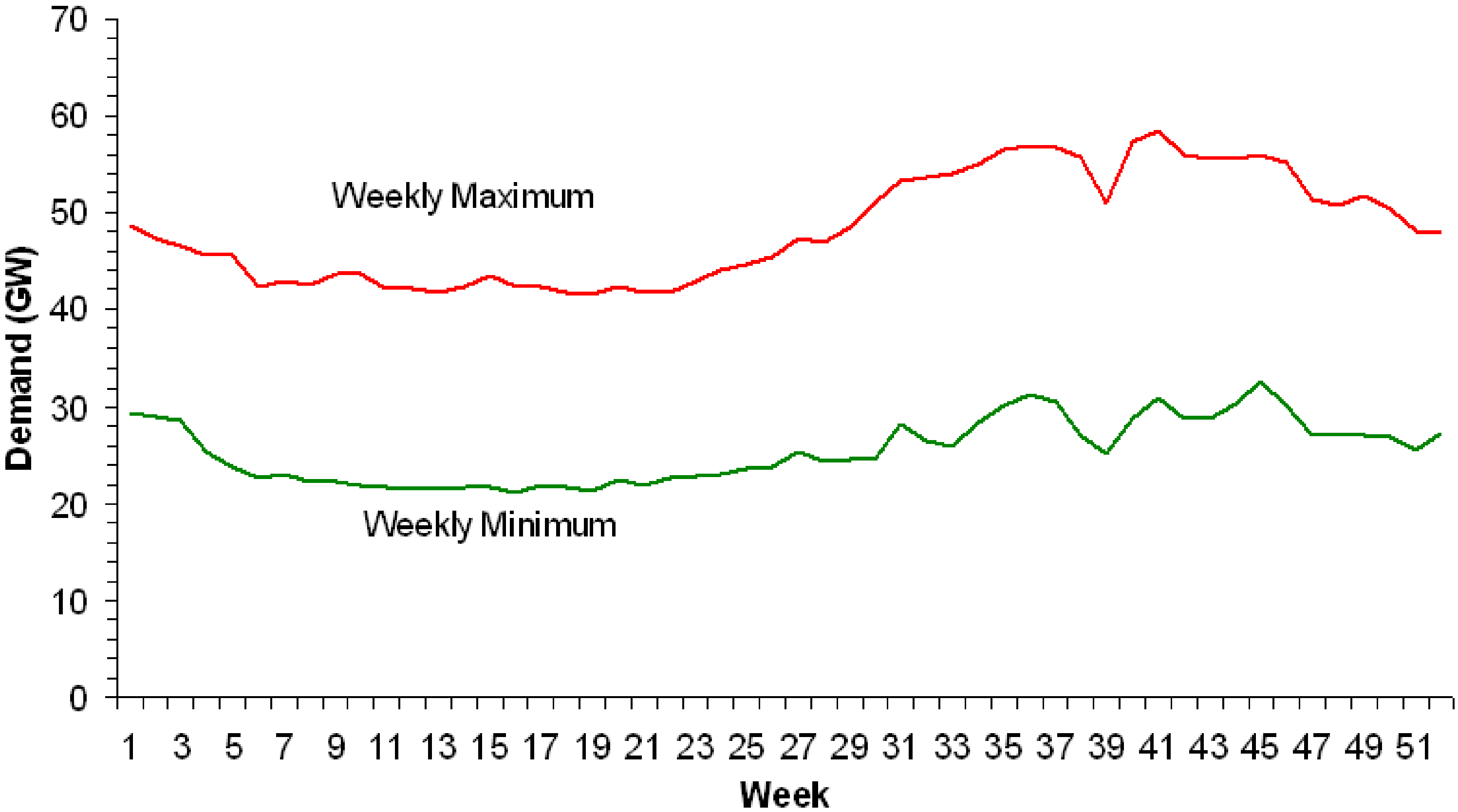


Figure 2.4 - GB Annual Load Duration Curve for 2008/09

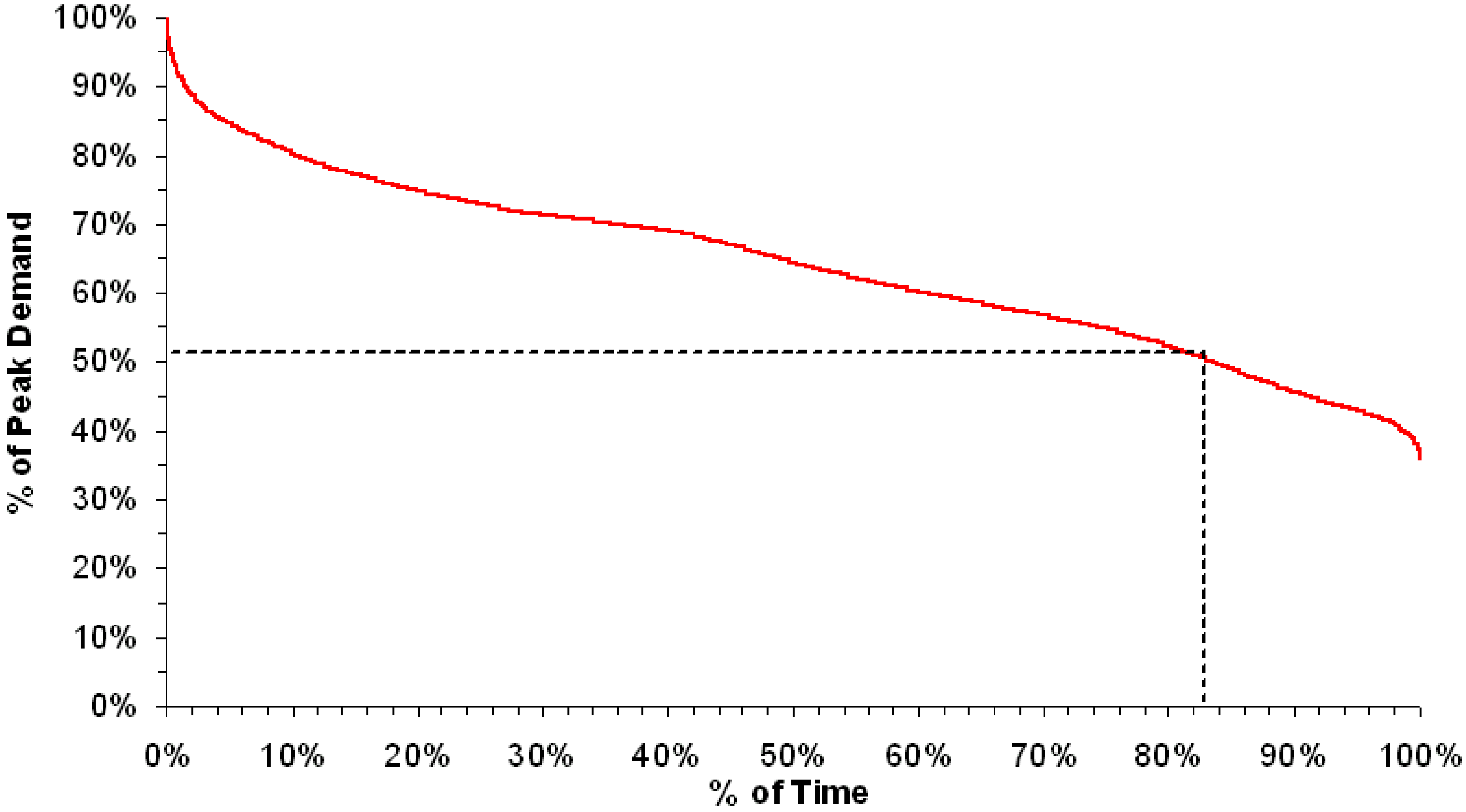


Figure 2.5 - Comparison of Customer-Based Forecast and National Grid Projections

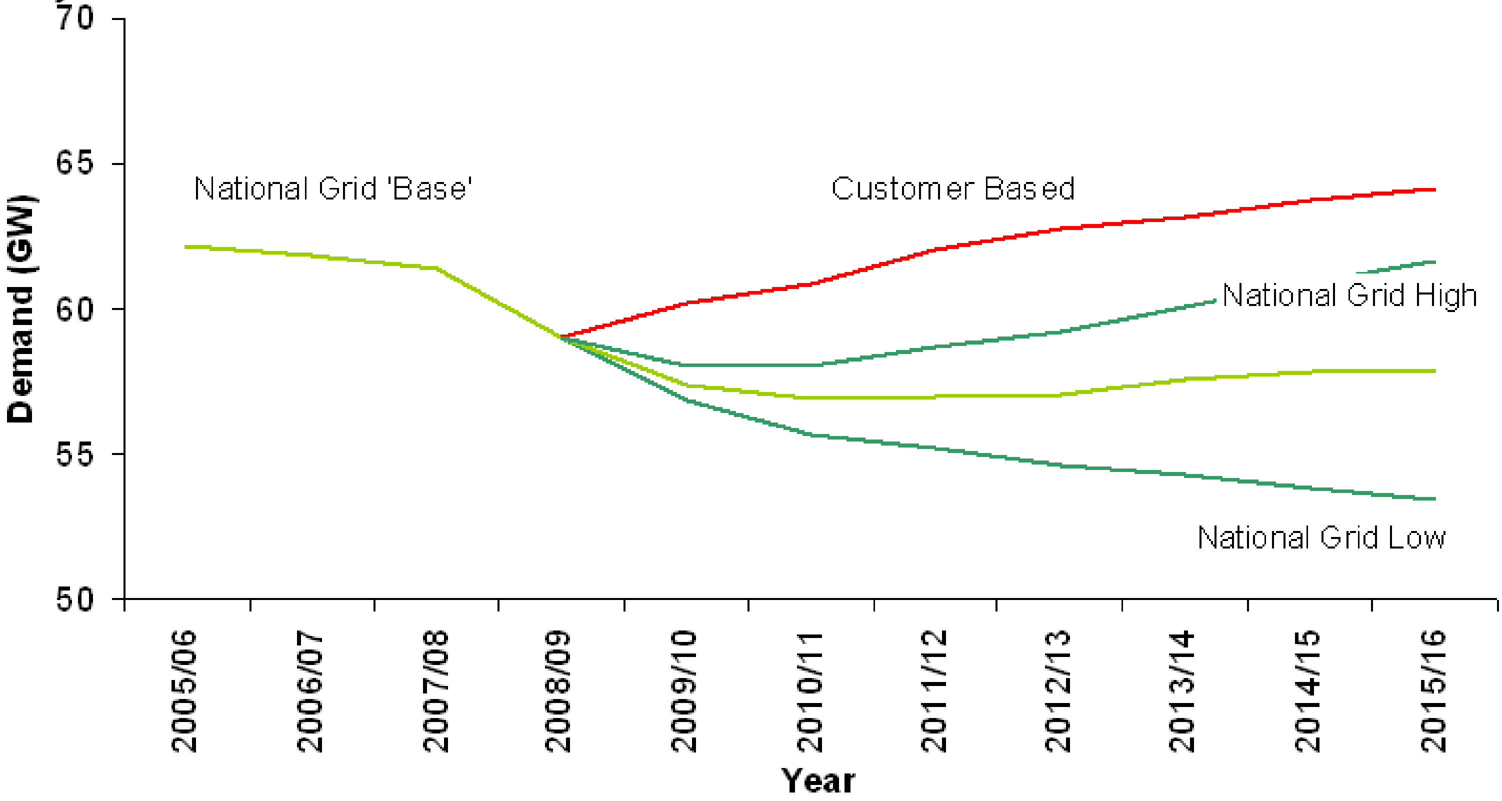
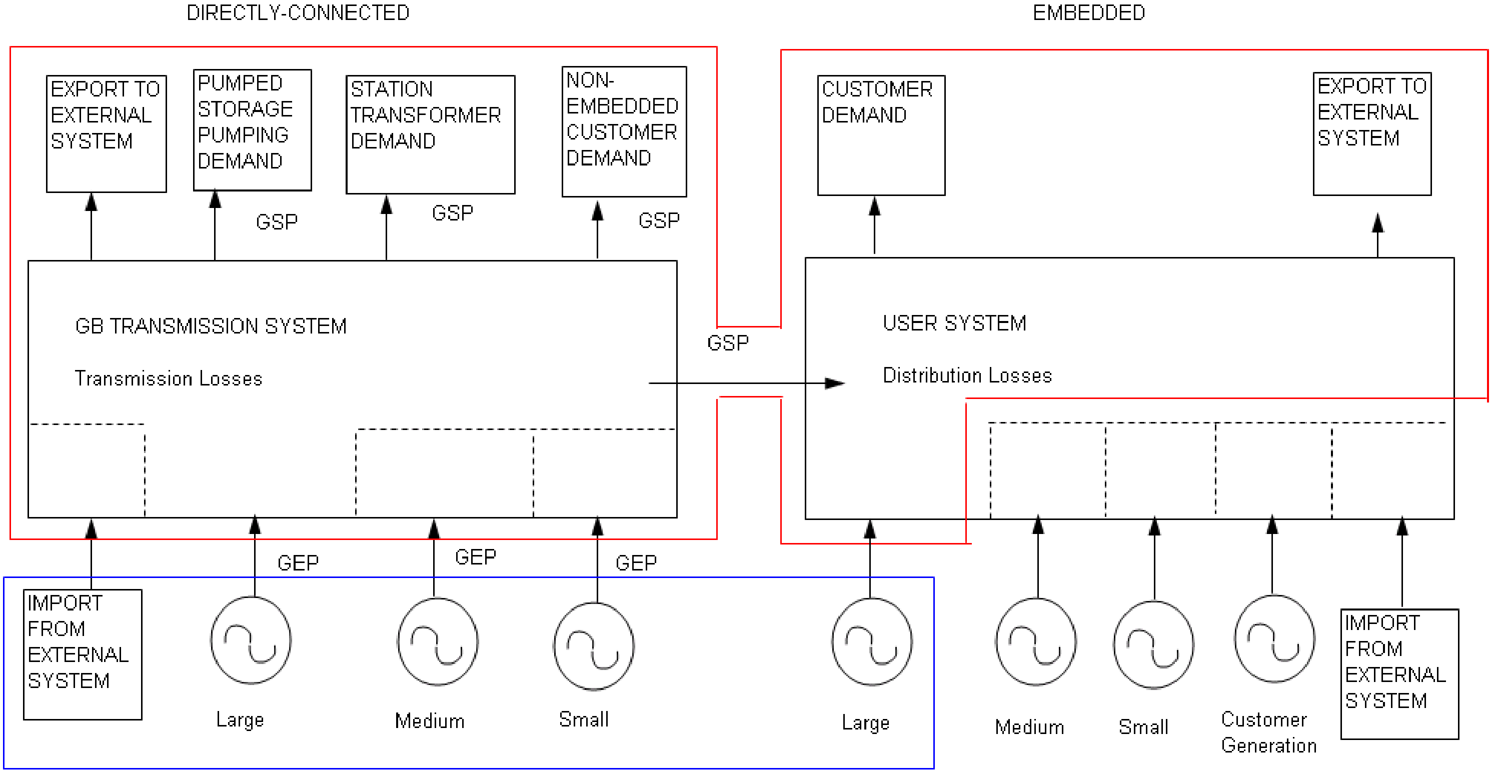


Figure 2.6 - ACS Peak GB Demand



Generation Used to Meet 'ACS Peak GB Demand'

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Table 2.1 - 'User' Based ACS Peak Demand Forecasts (GW)

Forecast	Description	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016
1	ACS Peak incl Station Demand, Exports to N Ireland via Moyle Interconnector and Exports to Republic of Ireland via "East/West" Interconnector	59	60.2	60.8	62	62.7	63.2	63.7	64.1
2	Station Demand	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
3	ACS Peak excl Station Demand and incl Exports to N Ireland via Moyle Interconnector and Republic of Ireland via "East/West" Interconnector (for plant margin evaluation)	58.4	59.6	60.2	61.4	62.1	62.6	63.1	63.5
4	N Ireland Export Demand via Moyle Interconnector	0	0.2	0.2	0.2	0.2	0.2	0.2	0.2
5	Republic of Ireland Export Demand via "East/West" Interconnector	0	0	0	0.4	0.4	0.4	0.4	0.4
6	ACS Peak excl Station Demand and Exports to N Ireland and Republic of Ireland (for ranking order & SQSS studies, where exports to N Ireland and Republic of Ireland are treated as negative generation)	58.4	59.3	60	60.7	61.4	61.9	62.4	62.8

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Table 2.2 - Peak Demands and Annual Electricity Requirements: Historical Outturns

Year	Actual Peak Demand (GW)	ACS Corrected Peak Demand (GW)	Actual Electricity Requirements (TWh)	Weather Adjusted Electricity Requirements (TWh)
2005/06	60.3	62.2	355.8	354.4
2006/07	58.4	61.8	347.3	350.5
2007/08	60.7	61.4	348.4	351
2008/09	59.2	59	340.7	337.6

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Table 2.3 - National Grid Base Forecast with High and Low Growth Demand Scenarios

Year	ACS Peak Demand (GW) Low Scenario	ACS Peak Demand (GW) Base Scenario	ACS Peak Demand (GW) High Scenario	Annual Electricity Requirements (TWh) Low Scenario	Annual Electricity Requirements (TWh) Base Scenario	Annual Electricity Requirements (TWh) High Scenario
2008/09 Prov	59	59	59	337.6	337.6	337.6
2009/10	56.8	57.4	58.1	322.1	325.9	330.2
2010/11	55.7	56.9	58.1	315.1	323	329.9
2011/12	55.2	57	58.7	311.6	323.1	333
2012/13	54.6	57	59.2	307.5	323	335.4
2013/14	54.3	57.6	60.1	303.9	324.7	338.8
2014/15	53.9	57.8	60.9	301.3	325.8	343
2015/16	53.4	57.8	61.6	298.4	325.7	347

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Table 2.4 - National Grid Base, High and Low Economic Growth Scenarios

Forecasts (% per Annum)	GDP	Household Expenditure	Manufacturing Output	Service Sector Output
NGC 'Base' Forecast 2007/08 - 2014/15	0.9	1.4	-0.7	0.5
Low Growth Scenario 2007/08 - 2014/15	0.1	-0.2	-2.8	0.9
High Growth Scenario 2007/08 - 2014/15	1.8	3	1.4	1.9

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GB Seven Year Statement 2009

Introduction to Chapter 3

This chapter presents information on all sources of generation, which are used to meet the ACS Peak GB Demand as defined in the Glossary and presented in **Electricity Demand**. Accordingly, this chapter reports on all power stations directly connected to the GB transmission system, whether they are classified as Large, Medium or Small, all directly connected External Interconnections with External Systems and all Large power stations, that are embedded within a User System (e.g. distribution system).

Electricity Demand does not include demand which is supplied by embedded Medium and Small power stations or embedded External Interconnections with External Systems. Likewise, this chapter does not include information on these sources of generation. Such information is, however, included in **Embedded and Renewable Generation**.

Information provided in this chapter relates to those generators who are “Transmission Contracted” i.e. they have a contract for either an existing or a new connection. Hence the SYS Background is a factual list of contracted sites and is not a forecast of which generators are expected to remain in operation or which proposed new generation projects are deemed most likely to proceed to completion. Consequently, care must be taken when interpreting the overall capacity figures as a number of stations will close due to the Large Combustion Plant Directive (LCPD) and many of the proposed projects will not progress to a connection. In addition there may be some non-contracted projects not included within the SYS that may proceed to a connection during the seven years. The “Transmission Contracted” generation capacities show a mix in terms of fuel type, geography and system disposition.

The chapter concludes with a short section on 'Generation Terminology'. Readers who are unfamiliar with current terminology are advised to first read that section before moving on to the main body of the chapter.

Scope

The “Transmission Contracted” SYS Background incorporates all existing and proposed projects with a signed bilateral agreement and only includes the closure of existing plant if we have been informed by the generator. Consequently, only the magnox plants at Oldbury and Wylfa, where closure dates have been published by BNFL Magnox Electric, are shown as closing over the period.

An exception to the general rule of only including sites with bilateral agreements is Alcan's Lynemouth power station, which is embedded, Licence exempt and Large but currently has yet to sign a Bilateral Agreement. However, this power station does exist and is capable of spilling large amounts of power onto the system (circa. 420MW). In consequence, it is subject to special treatment in this GB SYS in that it is treated as "Transmission Contracted". Its capacity is not netted of the demand forecasts submitted by Users but, instead, is included as generation capacity used to meet the ACS Peak GB Demand.

The SYS Background

The generation background presented in this chapter, together with the 'User' based demand background and the transmission background described in **Electricity Demand** and **GB Transmission System** respectively, form the basis of the SYS background upon which most of the studies and analyses presented in this Statement are based. These three elements of the SYS background (namely: demand; generation; and transmission) are internally consistent. For example, the transmission background of Chapter 6 includes all transmission connection developments cited explicitly in the relevant Bilateral Agreement as being necessary to permit the connection of the generation contained in the generation background presented in this chapter. It is worth repeating, however, that the SYS background does not include any transmission development that may be needed to accommodate prospective projects of new generation or demand, that did not have an appropriate Bilateral Agreement in place on the Data Freeze Date of 31 December 2008.

Consents Status (S36 and S14)

The requirements for generation projects to obtain the necessary consents (i.e. under Section 36 of the Electricity Act 1989 and Section 14 of the Energy Act 1976) is explained in **Market Overview**. Many of the tables giving information on generation introduced later in this chapter include an indication of whether that plant has obtained section 36 and/or section 14 (where appropriate) consents or not. This information is useful when considering the relative likelihood of a project proceeding to completion.

For completeness, **Table 3.2** and **Table 3.3** have also been included. **Table 3.2** lists power stations, not yet under construction, for which section 36 and/or section 14 consent has been given. **Table 3.3** lists power stations, not yet under construction, for which section 36 and/or section 1414 has been given.A variety of information sources are used both internal to National Grid and external websites such as the Department of Energy and Climate Change (DECC), the British Wind Energy Association (BWEA) and the Scottish Executive.

Finally, **Figure A.1.5** shows the location of National Parks in England, Wales and Scotland. Consents may be easier to obtain outside these areas.

Commissioning Dates

The commissioning year given will normally correspond to both the 'contract' date and the assumed date of actual full commercial output from the plant in question. However, in some cases full commercial output may slip into the years following the contract date. In such cases, the assumed generation commissioning dates given reflect the advice of the relevant generator.

Rather than strict adherence to a formal transmission contracted position, pragmatic assumptions relating to commissioning dates in the earlier years were, where considered appropriate, adopted in previous Seven Year Statements in order to enhance the relevance of the information provided. Such assumptions were made without prejudice and were intended to recognise the extant consent status of the plant in question and the progress towards completion of the project.

However, in this year's Statement no such pragmatic assumptions were considered necessary. Nevertheless, **Table 3.4**, which would normally list any generation projects affected by such assumptions, has been retained for completeness.

Generation Capacity

Power Station Capacities

Table 3.5 presents details of all power stations falling within the scope of this chapter including the output capacity of each over the seven year period, 2009/10 to 2015/16. Amongst other things, **Generation Terminology** explains that the relevance of the generation capacity terms Transmission Entry Capacity (TEC), Connection Entry Capacity (CEC) and 'Size of Power Station' is a function of the type of Bilateral Agreement in force. For a Bilateral Connection Agreement (BCA), both TEC and CEC are relevant. For a Bilateral Embedded Generation Agreement (BEGA) only TEC is relevant. For a Bilateral Embedded Licence Exemptable Large Power Station Agreement (BELLA), neither TEC nor CEC exists and the term 'Size of Power Station' becomes relevant.

In **Table 3.5** the type of power station capacity (i.e. TEC or 'Size of Power Station') given for each of the seven years is denoted by an appropriate entry (i.e. 'yes') in the columns headed 'TEC' and 'Size of Power Station' towards the right hand side of the table. Where CEC is relevant (i.e. for a BCA) a separate entry is included in the column headed 'CEC'. Please note that values of CEC are given in respect of year 2009/10 only.

The information is presented on the basis of Licensee then on power station type. For ease of reference, the SYS Study Zone, in which each Power Station is located, is also given as is the Tariff Zone. The SYS Study Zones are explained under **SYS Boundaries and SYS Study Zones** and Tariff Zones are explained under **Use of System Tariff Zones**.

Please note that the External Interconnection between Scotland and Northern Ireland (Moyle Interconnector Ltd) normally operates in export mode. However, a TEC of 80MW import has been registered for this Interconnector and this is reflected in **Table 3.5** . . Other tables in this Statement may include a more pragmatic figure to reflect export (rather than import) from Scotland to Northern Ireland as being the likely mode of operation at times of the GB system peak demand. An example is **Table 7.1** (GB Generation Ranking Order) presented in **GB Transmission System Performance**. There are a number of other differences between **Table 3.5** , which is intended to provide information on the formal contracted (TEC) position, and **Table 7.1**, which includes a number of informed pragmatic assumptions designed to reflect the likely operation of generation sources at peak for the purpose of power flow analyses.

Inspection of **Table 3.5** reveals that the aggregate contracted power station capacity (TEC and/or 'Size of Power Station') rises from 83.6GW in 2009/10 to 109.8GW by 2015/16. This is an overall increase of 31.3% or 26.2GW over the period from the 2009/10 winter peak to the 2015/16 winter peak. This net increase is made of the following

- an increase of 10.3GW in CCGT capacity (+12.3%);
- an increase of 5.8GW in onshore wind generation capacity (+6.9%);
- an increase of 5.3GW in offshore wind generation capacity (+6.3%);
- an increase of 3.3GW in coal generation capability (+4.0%);
- an increase of 2.1GW in new import capability (+2.5%);
- an increase of 851MW in Biopower capacity (+1.0%);
- an increase of 56MW in Hydro capacity (+0.1%); and
- a decrease of 1.45GW in Nuclear Magnox capacity (-1.7%).

The largest change is due to the 10.3GW increase in CCGT plant capacity, which constitutes a 12.3% increase in overall capacity over the period. On this basis, the capacity of CCGT plant will overtake that of coal by 2010/11. By 2015/16, CCGT capacity will exceed coal capacity by 6.5GW and account for 35.3% of the total transmission contracted installed generation capacity. Note that this growth in CCGTs of 10.3GW excludes those stations under construction that are contracted to connect in 2009/10 e.g. Langage, Marchwood, Immingham, Starythorpe, Severn Power (phase 1) and West Burton (phase 1) which amount to 5GW. In addition there are a number of other CCGTs under construction e.g. Severn Power (phase 2), West Burton (phase 2&3) and Grain which amount to 2.6GW and are included in the 10.3GW figure.

The next largest increases are due to the growth in Wind generation, with onshore wind accounting for a 6.9% increase and offshore wind accounting for a 6.3% increase in overall capacity. Wind generation capacity (both onshore and offshore) is set to rise to 11GW by 2015/16. Currently around 1.8GW of wind is under construction with 1.2GW due to connect in 2009/10 and 0.6GW contributing to the 11.1GW growth over 2009/10 to 2015/16.

The above capacities do not include the embedded Medium and Small generation and embedded External Interconnections with External Systems. The capacity of such embedded generation sources is the subject of **Embedded and Renewable Generation**.

It should be remembered that the above figures reflect the current contracted position and take no account of future uncertainty. As mentioned previously, it is reasonable to suppose that further new applications for power station connections will be received and, at the same time, some existing contracts may be modified or terminated and some existing power stations will close.

Large Combustion Plant Directive

The introduction of the Large Combustion Plants Directive (LCPD) requires large electricity generators to meet more stringent air quality standards from 1 January 2008. Plant which has “opted out” of this obligation will have to close by the end of 2015 or after 20,000 hours of operation from 1 January 2008, whichever is the sooner. This affects some 12 GW of coal and oil-fired generating plant which will therefore now close by 1st January 2016. However, the exact timing of these closures is a commercial matter for plant owners, taking into account factors such as other environmental restrictions and the state of repair of the plants. Consequently, it is impossible to predict with certainty the precise timing of the impact of the LCPD on generation capacity particularly if a replacement station is planned to be constructed on the same site. Hence no allowance has been made within the 2009 GB SYS for LCPD affected closures. For more detail on the LCPD please refer to the following link (**Defra, UK - Environmental Protection - Air Quality - Large Combustion Plants Directive**):

http://www.defra.gov.uk/environment/airquality/eu-int/eu-directives/lcpd/index.htm

Generating Unit Capacities

The 'effective output' capacity of each Generating Unit is given in **Table 3.6** along with a range of additional data relevant to individual Generating Units or ‘sets’ within each power station. The 'effective output' is simply the Registered Capacity of each Generating Unit scaled down, where both appropriate and necessary, such that the aggregate output of all Generating Units at a power station is limited to the value of the relevant Power Station TEC. This would not be ‘appropriate’ for a generating unit generating unit covered by a Bilateral Embedded Licence Exemptible Large power station Agreement (BELLA), since a BELLA power station does not have a TEC. Nor would it be ‘necessary’ should the aggregate unit Registered Capacity at a power station be equal to or less than the station TEC. For ease of reference, the SYS Study Zone is again included. **Table 3.6** reflects the contracted position for the winter peak of 2009/10 as known at the data freeze date of 31 December 2008.

Three phase fault infeeds and reactive ranges are also given and these are at the interface between the Generating Unit and the GB transmission system i.e. on the higher voltage side of the generator transformer. This information is supplied to us by Users as part of their Week 24 Grid Code submissions.

Generation Capacity Additions

Table 3.7 lists the changes in the contracted capacity of generation, which has either actually commissioned or is contracted to commission, over the period from the winter peak of 2005/06 to the winter peak of 2015/16. Please note that capacities up to and including the winter peak of 2002/03 were based on power station Registered Capacity (RC) while capacities for 2003/04 onwards are based on either power station Transmission Entry Capacity (TEC) or power station ‘Size of Power station’, as appropriate (TEC being appropriate for BCA and BEGA power stations and ‘Size of Power Station’ being appropriate for BELLA power stations).

Table 3.7 does not include any subsequent increases or decreases in capacity of plant that was commissioned before the year 2005.

However, as well as new (i.e. commissioned, or to be commissioned, from year 2005 onwards) transmission contracted generation, the table does also include increases due to plant being returned to service from reserve (or closure), increases in import capabilities from External Systems, and some minor proposed changes in TEC. For consistency between the various tables presented in this Statement, all generation expected to commission before the winter peak of 2008/09 is classified as ‘existing’existing’ or ‘under construction’.

The status of each development is shown in terms of whether the station is existing (by the winter peak of 2008/09), under construction and otherwise whether both S36 and S14 (where relevant) consents have been obtained. A zero entry (e.g. Netherlands Interconnector Stage 1) has been used for projects where a Modification Application has been submitted, or is to be submitted, to vary the construction programme/ commissioning date. The year of the zero entry indicates the original contracted commissioning date.

The annual commissioning stream is included in the penultimate line of **Table 3.7**. . This may be used as an indicator to the future level of activity over the period. A relatively high level of activity in relation to capacity increases is indicated for the yeas 2010/11 (almost 7.4GW) and 2011/12 (just under 7.0GW). In these two years some 16.2% of the new capacity is from onshore wind generation to be located in Scotland. Similarly, some 16.9% of the new capacity is from offshore wind generation to be located in England and Wales. It is worth remembering, however, that, in the event, there may well be a more graded increase in activity over a number of years. The fact that a project is currently 'transmission contracted' is not an absolute guarantee that the project will proceed to completion since there are other factors, which may also influence that outcome (e.g. financing, fuel prices, consents etc.).

Overview of Generation Capacity Additions

Table 3.8 complements **Table 3.7** by providing an overview of the generation capacity additions over the period from from 2005/06 to 2015/16. For instance, of the 35.2GW of additional transmission contracted capacity since 2005/06, 14.7GW or 41.7% is CCGT plant and 13.5GW or 38.4% is due to wind farms (both onshore and offshore). Similarly, of the 11.9GW of new contracted capacity either existing or under construction, 7.0GW or 59% is CCGT plant and 2.9GW or 24.6% is due to wind farms.

Table 3.8 also separately identifies the capacity of future plant by type and according to whether the necessary consents have been obtained.

Additional Contracted Generation Capacity

Table 3.9 lists generation projects that have become classed as transmission contracted since 31 December 2007. In effect, this means since the data freeze date for the information published in our 2008 issue of the GB Seven Year Statement. The table shows that, since that time, Bilateral Agreements have been entered into for just under 2.9GW of new generation capacity on the NGET system. This includes: 709MW of onshore wind farms; 1330MW of CCGT capacity; 375MW of interconnector capacity; and 449MW of biomass capacity.

Disconnections

Disconnection is normally the irreversible closure of a power station and requires formal notification to be given to us at least six months prior to the event. **Table 3.10** lists notified generation disconnections (closures) since the year 2005 inclusive. In total there is 2.5GW. Please note that capacities up to and including the winter peak of 2002/03 are based on power station Registered Capacity (RC) while capacities for 2003/04 onwards are based on power station Transmission Entry Capacity (TEC). The year indicated on the table is the year of closure and normally implies that the power station will not be generating over the subsequent winter peak. In the case of Dungeness A and Sizewell A, both stations were actually closed on 31 December 2006, which is within the 2006/07 winter peak period.

Due to the Large Combustion Plant Directive opted-out plant, comprising of 8.5GW of coal and 3.5GW of oil, some 12GW of closures will take place by 1st January 2016; however, due to the uncertainty of the closure dates and whether any TEC would be terminated no allowance has been made for these closures over the seven years. For the 2010 GB SYS this situation will need to be addressed.

Decommissionings

Decommissioning also requires six months formal notification but is not irreversible. Generating Units with a notified Registered Capacity of zero are, for the purpose of this Statement, in the same category as decommissioned plant.

A Generator may wish to decommission or mothball a Generating Unit for a relatively long period for commercial reasons. In such an event the Generator may also wish to affect a corresponding reduction in the power station TEC in order to reduce the Use of System charges. At a later date, he may choose to ‘re-commission’ the generating unit and return the Power Station TEC to its appropriate value.

As explained in PC.4.3.1 of the GB Grid Code, NGET use the TEC data (and CEC data for that matter) from the relevant Connection and Use of System Code (CUSC) Contract. The value of TEC is specified in Appendix C of the appropriate Bilateral Connection Agreement or Bilateral Embedded Generation Agreement. These are agreements entered into pursuant to paragraph 1.3.1 of the CUSC.

Paragraph 6.30 of the CUSC explains how revisions to the value of TEC may be made. TEC may be decreased provided that certain specified notice is given to National Grid. Generators are entitled to request an increase in TEC, up to a maximum of the relevant CEC, through the more protracted Modification Application process.

Where we have received notification from the Generator (in accordance with the CUSC requirements) that a particular generation source is to reduce its value of TEC, then the reduced value is accordingly attributed to that plant for the purpose of the power flow studies and analyses contained in this Statement. In the extreme, we may receive notification that a particular plant has reduced TEC to zero. This could, under certain circumstances, mean that additional transmission reinforcement work would be required before such plant is able to subsequently re-register TEC at a higher level and this may cause a delay. In view of this, the Generator may choose to maintain the value of Power Station TEC throughout in order to avoid any subsequent delays. Increases in station TEC above the extant contracted value are not possible without an appropriate Modification Application from the generator to us to modify the site specific Bilateral Agreement.

Where the Generator has notified us that the Output Usable is zero (e.g. unavailable due to maintenance), the full value of station TEC is still attributed to that plant for the purpose of power flow and fault level studies. This ensures that no transmission reinforcement, and possible delay, will be necessary when the plant is repaired and returned to service.

Table 3.11 lists Generating Units which have either been formally notified by the owner as decommissioned (effectively RC=0) or simply notified zero Registered Capacity covering the seven year period of this Statement. In either event they may effectively be classed as unavailable. The year shown is the year in which the decommissioning took place. The capacity shown is the capacity prior to decommissioning. Please note that decommissioning is commonly on a generating unit basis for which the terms Registered Capacity or Connection Entry Capacity apply. Transmission Entry Capacity relates to the power station and does not exist on a unit basis. However, the values of RC given in **Table 3.11** may be taken as an equivalent reduction in power station TEC.

To provide a more complete picture, the table includes both positive and negative entries; a positive entry indicating when a plant is decommissioned; and a negative entry when a plant is returned to service. Accordingly, the table indicates that unit 1 at Fawley was decommissioned in 1994 (indicated by a positive entry) and returned to service in 2006 (indicated by a negative entry). Similarly, units 1A, 1B, 1S, 2A, 2B, 2S at Killingholme were decommissioned over the period 2002 to 2004 and returned to service in 2006.

Table 3.11 shows that there is currently an overall reduction in potential power station capacity of some 2.9GW comprising: 534MW of OCGT plant; 2035MW of Oil plant; and 350MW of Coal plant. However, it is unlikely that all this capacity could be returned to service. Of the 2.9GW, perhaps some 500MW to 1GW has the greatest potential to return to service. Even then, it should also be borne in mind that, were individual plants to be re-commissioned/returned to service, the full previous capacities may not necessarily be realised.

Interconnections with External Systems

The GB transmission system currently has directly connected External Interconnections with the External Systems of France and Northern Ireland. The commissioning of an External Interconnection with the Netherlands system is planned for 2010/11. The commissioning of two External Interconnections with the Republic of Ireland system are planned for 2011/12. The opportunities for making use of these External Interconnections are outlined in **Opportunities**. **Table 3.12** sets out the notional import and export capabilities across each of the External Interconnections and the normal direction of flow.

Please note, however, that the transfers given in **Table 3.12** reflect the capabilities of the Interconnectors. Other tables in this Statement may show different transfers depending on the purpose of the table. For instance, **Table 3.5** is designed to reflect the formal (TEC) position and consequently shows an import into Scotland of 80MW across the Northern Ireland Link, and an import into Wales of 875MW across the Republic of Ireland Link. The demand forecasts shown in rows 1 and 3 of **Table 2.1** include a 250MW export from Scotland to Northern Ireland, and a 437.5MW export from Wales to the Republic of Ireland. **Table 7.1** (GB Generation Ranking Order) presented in **GB Transmission System Performance** includes a number of informed pragmatic assumptions designed to reflect the likely operation of generation sources at peak for the purpose of power flow analyses. **Table 7.1** includes an export from Scotland to Northern Ireland over the Interconnector of 250MW, which is shown as negative generation. **Table 7.1** also includes an export from Wales to the Republic of Ireland over the Interconnector of 437.5MW, which is shown as negative generation.

Cross-Channel Link

The cross-channel link with France is a DC link consisting of four pairs of cables connecting converter stations at Sellindge in Kent and Les Mandarins near Calais. The 1988 MW import level at peak, which is applicable throughout the seven year period, is net of Interconnector losses. At peak, the link is normally used for imports to the GB transmission system.

Northern Ireland Link

The link between Scotland and Northern Ireland was commissioned in December 2001 with commercial operation commencing in January 2002. The interconnector is a DC link connecting converter stations at Auchencrosh in the 'South' zone of the SPT system, which corresponds to SYS Study Zone Z6, and Islandmagee in Northern Ireland. SYS Study Zones are explained under **SYS Boundaries and SYS Study Zones**. The 500MW Auchencrosh converter station is supplied by a 275kV overhead line from Coylton substation and this is shown in **Table 3.12**.

Although this Interconnector can operate with power flows in either direction, the power flow has been predominantly from Scotland to Northern Ireland. While the link has both an export and import capability, it is normally used for export to Northern Ireland. An export (i.e. a demand) of 250MW may be assumed for the winter peak of each year for the purpose of power flow analyses. This transfer to Northern Ireland may be treated as being equivalent to demand and has been taken into account in the demand forecasts of Chapter 2.

Netherlands Link

A DC link for interconnection with the Netherlands electricity system is planned to commission by 2010. The link will be of capacity up to 1320MW(although initially it will have a TEC value of 1200MW), capable of bi-directional flow, and will be connected at Grain 400kV substation. At peak, the link will normally be used for imports to the GB transmission system.

Republic of Ireland Links

Two DC links for interconnection with the Republic of Ireland electricity system are planned to commission by 2011. One link will be of capacity up to 500MW, capable of bi-directional flow, and will be connected at Deeside 400kV substation. The other link will be of capacity up to 375MW, capable of bi-directional flow, and will be connected at Pentir 400kV substation. At peak, both links will normally be used for exports from the GB transmission system.

Generation Mix

Figure 3.1 illustrates the main changes, since 2005/06, in the generation capacity of transmission contracted plant. For the underlying detail please refer to: **Table 3.7** (changes in station capacity); **Table 3.10** (closures); and **Table 3.11** (unavailable plant). The level of capacity reductions does not change beyond 2010/11. This partly reflects the fact that generators are not required to provide formal notification of disconnections or decommissioning until 6 months prior to the event. However, no allowance has been included for those stations that will close on or before 31st December 2015 due to opting out of the LCPD. These closures amount to 12GW of coal and oil capacity and have been left in because of the uncertainty over closure date and the potential for them to be available at peak in 2015/16 if the peak is prior to Christmas. The potential relatively high level of activity in 2009/10, referred to previously when considering **Table 3.7**, is evident in **Figure 3.1** in the large step increase in additional capacity in that year.

Figure 3.1

Click to load a larger version of Figure3.1 image

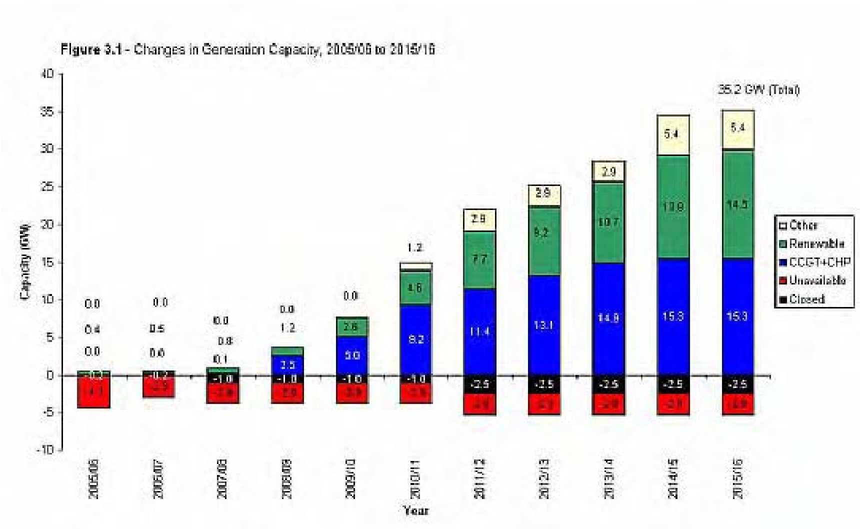
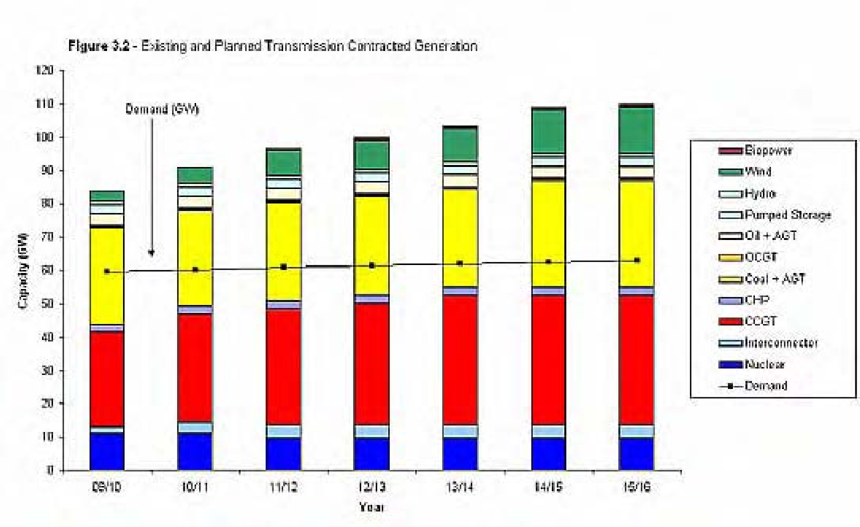


Figure 3.2 illustrates the generation mix from 2008/09 to 2014/15 and includes all transmission contracted generation whether existing or planned (i.e. the 'SYS background') based on **Table 3.5** . The customer-based demand forecast of row 5 of **Table 2.1** has been superimposed on the generation mix to give an indication of the apparent surplus of generation over demand in **Plant Margin**. The demand forecast of row 5 of **Table 2.1** was selected as being the most appropriate for this comparison since that forecast not only excludes station demand but also excludes exports to Northern Ireland and the Republic of Ireland, making it compatible with **Table 3.5**, which includes TEC of 80MW for imports from Northern Ireland, and TEC of 500MW for imports from the Republic of Ireland from 2011/12 onwards. The different fuel types are given in approximate order of economic operation. Please note, however, that this is indicative only and no account has been taken, for instance, of generation availability. Nevertheless, the figure does imply a variation in the type of marginal plant used to meet the demand over the seven years considered. There is a reduction in coal capacity used to meet the demand; not so much in absolute terms, since future as yet unnotified closures are not included, but rather in relative terms. In the later years, the closure of Magnox plant by 2011/12 is offset by the growth in Interconnector, CCGT and Wind generation capacity both in absolute and relative terms.

Figure 3.2

Click to load a larger version of Figure3.2 image



In considering the above information it is important to note the following three points:

- the generation capacity estimates do not take account of the possibility of modification of existing connection agreements, additional new connection agreements being signed, possible future closures which have not yet been formally notified to us for which only 6 months notice of closure is required or the return to service of plant held in reserve;
- whilst there has been some 35.2GW of additional contracted generation capacity since 2005/06, only 3.6GW is in service (by 2008/09), 8.3GW is under construction and construction work on the remaining 23.3GW (7.7GW of CCGT, 3.3GW of coal, 10.6GW of wind farms, 0.88GW of Interconnection capacity and 0.85GW of Biopower) has not yet started (see Table 3.8) as at the data freeze date of 31 December 2008; and
- the full import capability has been assumed for the External Interconnections with France and the Netherlands.

Generation Disposition

Figure A.1.1 of Appendix A gives the geographical location of all transmission contracted Large power stations, whether directly connected or embedded within a distribution system that are existing (as at 2009/10). Directly connected Medium and Small power stations are also shown as are directly connected External Interconnections with External Systems. These generation sources form the generation background contained within the 'SYS background'. Large power stations which have been formally disconnected (closed) are not shown (see **Table 3.10**) but Large power stations with decommissioned Generating Units are shown (see **Table 3.11**). Embedded Medium and Small power stations and embedded External Interconnections are not shown.

The disposition of the above existing plant, and prospective future plant, in terms of its capacity and location around the system is particularly important when considering the performance (e.g. resultant power flows) of the transmission system, the need for transmission developments and the opportunities for connecting further generation (or demand) to the system; see **GB Transmission System Performance** , **GB Transmission System Capability** and **Opportunities**.

When considering bulk transfers of power around the system it is often useful to regard the transmission system as being made up of a number of zones. Such zones and the transmission boundaries between them are described in detail in **SYS GB Transmission System**.For consistency and ease of explanation, the generation dispositions described in the following paragraphs are also presented on a similar zonal basis.

Figure 3.3a , **Figure 3.3b** , **Figure 3.3c** , **Figure 3.3d** , **Figure 3.3e** and **Figure 3.3f** illustrate the change in total installed generation capacity by plant type for regions bounded by four of the main SYS Boundaries over the period 2009/10 to 2015/16. These regions of the system are referred to as Scotland (SHETL), Scotland (SPT), North, Midlands and South. The figures cover all transmission contracted generation (both existing and planned).

Figure 3.3a

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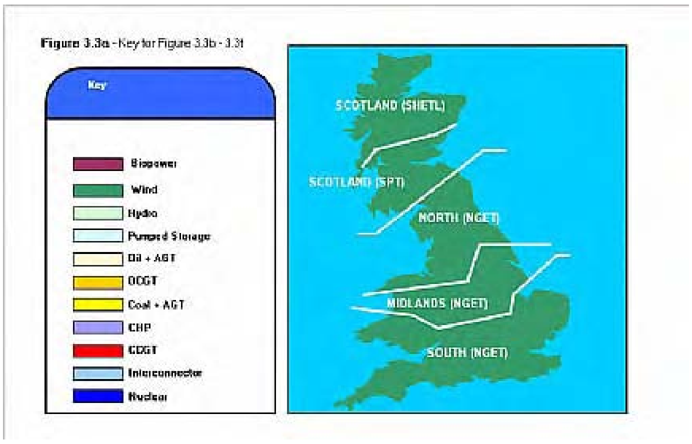

Figure 3.3b

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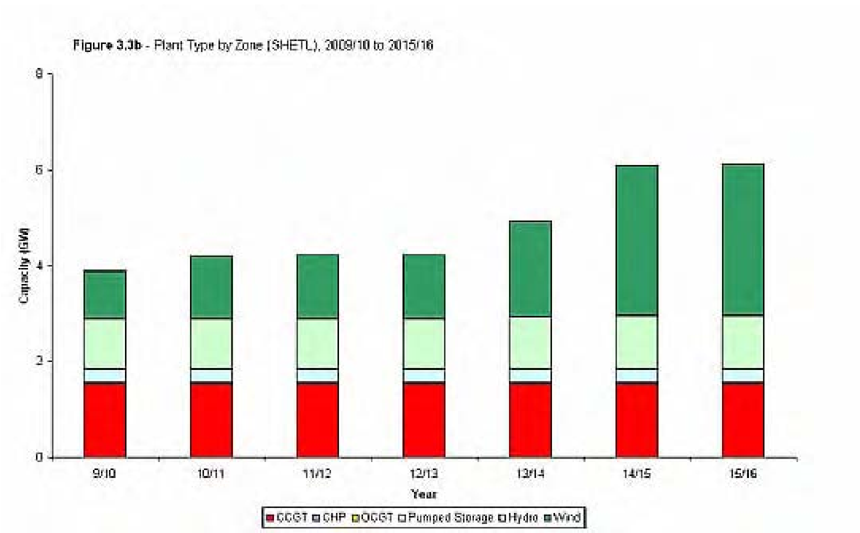

Figure 3.3c

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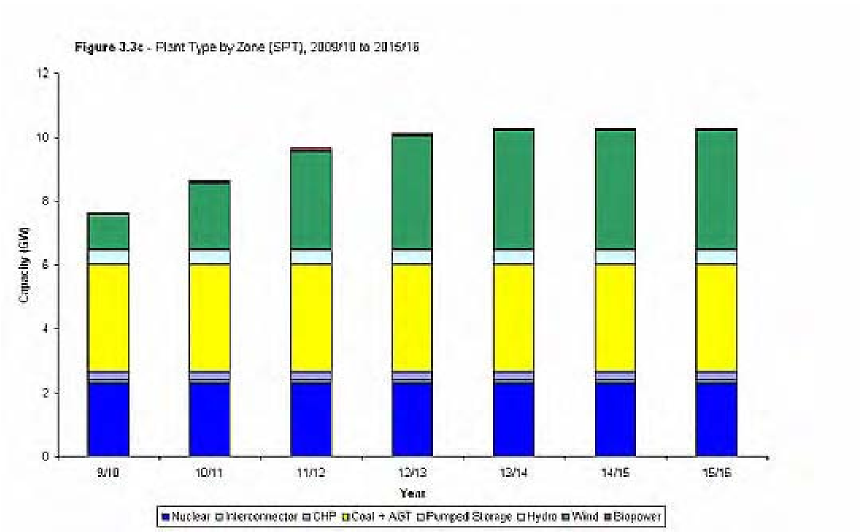

Figure 3.3d

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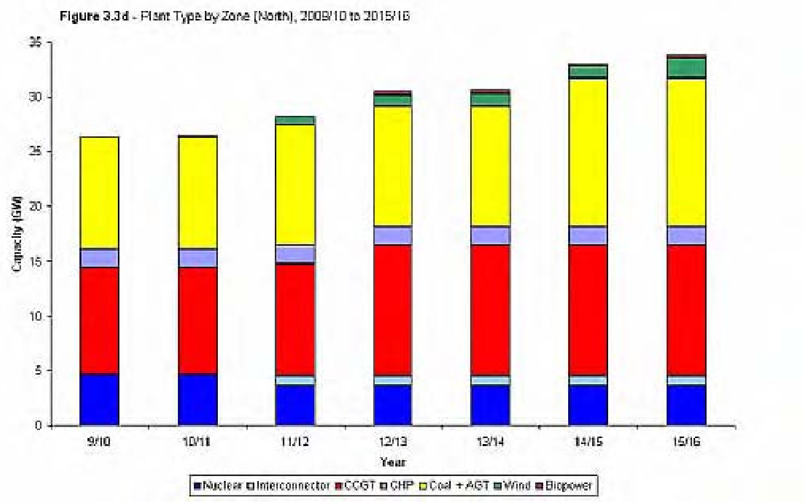

Figure 3.3e

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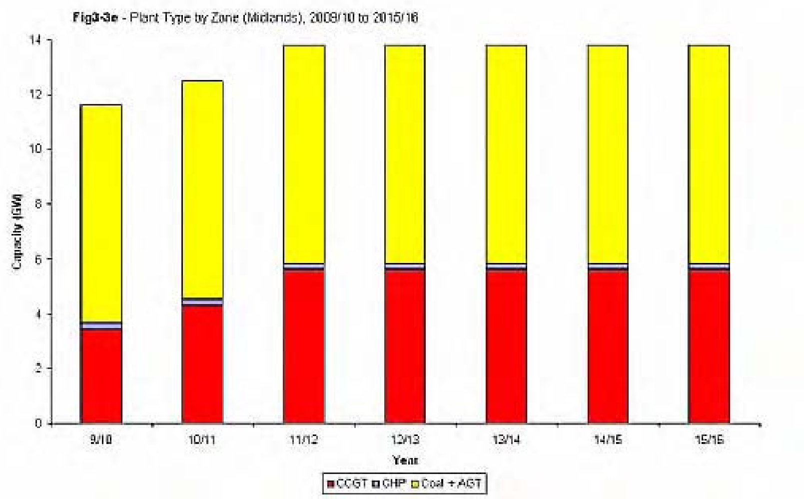

Figure 3.3f

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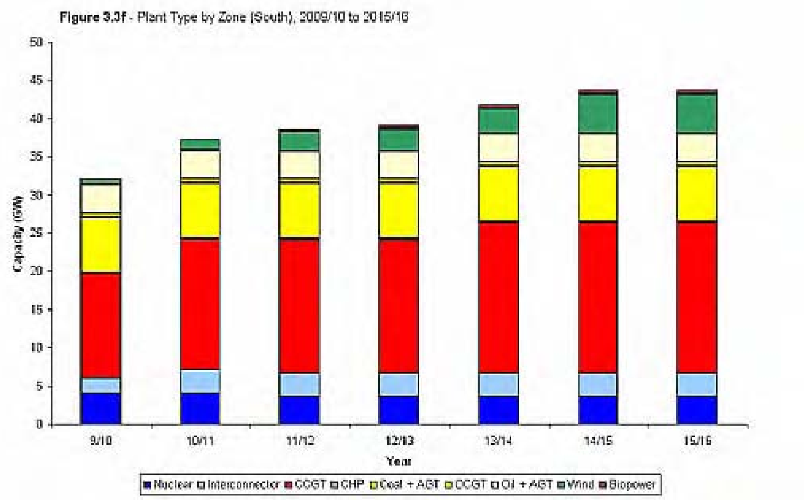

Figure 3.4 summarises the Scotland (SHETL), Scotland (SPT), North, Midlands and South disposition of all transmission contracted generation (both existing and planned) in the years 2009/10 and 2015/16.

The differences between the above spot years are detailed in **Table 3.13** , which shows a 23.6GW increase in generation capacity over the period. The table details the capacity changes on the basis of the SYS Study Zone Number described in **SYS GB Transmission System**. and referred to in **Table 6.4**.

Figure 3.4 shows that the installed generation capacity in the Scottish zones (SHETL & SPT), the South and the Midlands is growing in both real (MW) and percentage terms. The North zone displays growth in real terms but a decline in percentage terms.

Figure 3.4

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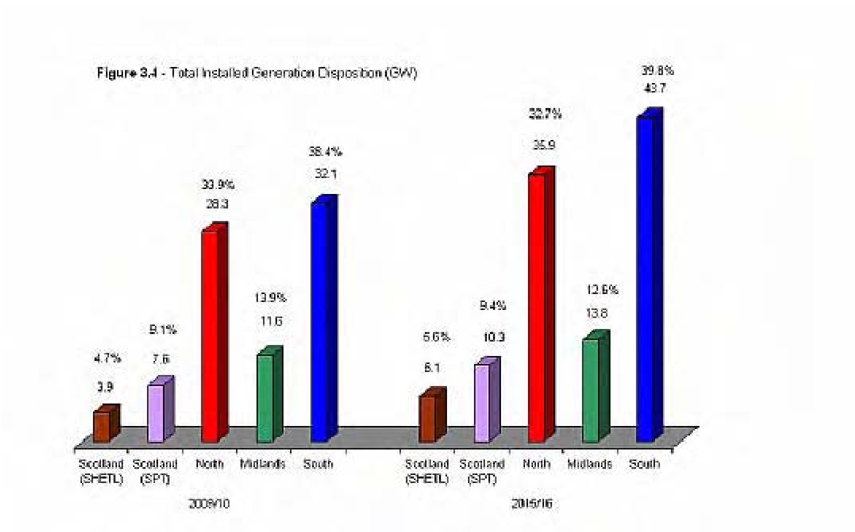

Figure 3.5 steps a little further back in time to illustrate how the disposition of new generation capacity has developed over the period 2005/06 to 2015/16.

Figure 3.5

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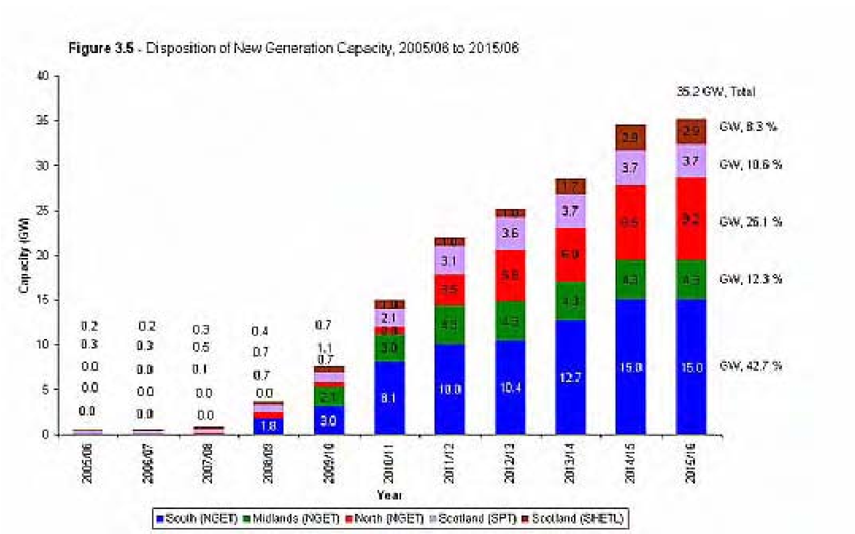

It should be remembered that **Figure 3.3a** to **Figure 3.3f** , **Figure 3.4** and **Figure 3.5** and **Table 3.13** are based on installed generation capacities. However, more importantly, it is the generation actually used in meeting the demand on the day, which determines the power flows at any given time. The 'GB Generation Ranking Order', which is explained in **GB Transmission System Performance**, is used to determine which generation is operated for the study purposes of this Statement.

By way of illustration, **Figure 3.6** shows the Scotland (SHETL), Scotland (SPT), North, Midlands and South disposition of installed generation (also shown in **Figure 3.4**) together with the regional ACS peak demand disposition. In both 2009/10 and 2015/16, the installed generation in Scotland (SHETL), Scotland (SPT), North and the Midlands exceeds demand, in some areas by a substantial amount. In the South, there is a more even balance in in 2009/10 with installed generation exceeding demand by a small amount. However, by 2015/16 installed generation exceeds demand significantly. Superficially, this would imply only relatively modest power transfers across the system.

Figure 3.6

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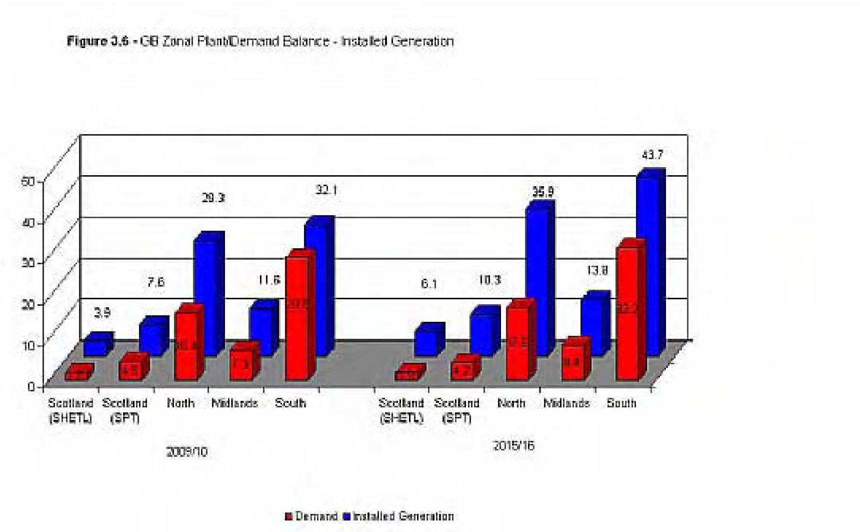

However, when the generation expected to be used to meet the demand is considered, a different picture emerges as illustrated in **Figure 3.7**. Again generation in Scotland (SHETL), Scotland (SPT) and the North exceeds demand in both years. However, in the Midlands and South much of the generation becomes non-contributory (i.e. not used in meeting the demand) such that the demand exceeds generation, by a substantial margin in the South, in both years; implying higher power transfers from the northern parts of the system, through the Midlands to the South. The power transfers at the time of peak under the 'SYS background', are reported in more detail in **GB Transmission System Performance**.

Figure 3.7

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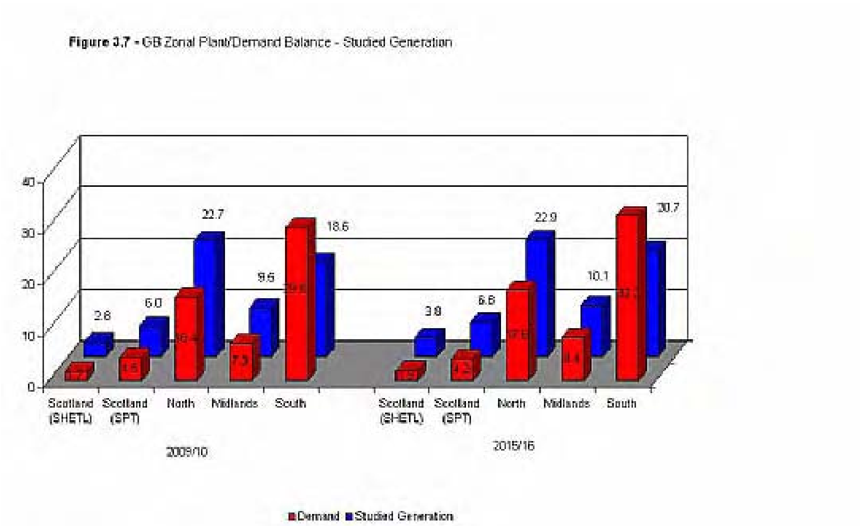


Additional information on generation location is given in **Table 3.14** and **Table 3.15**, which show amongst other things, the disposition on the basis of SYS Study Zone and plant type for the years 2009/10 and 2015/16 respectively.

Finally, to provide a more complete picture, **Table 3.16** lists generation projects for which the appropriate bilateral agreement is in place but which are scheduled to commission beyond the scope of this GB SYS (i.e. after 2015/16)

Generation Terminology

Generation Capacity

There are a several terms within the Electricity Supply Industry of Great Britain, which are currently used to describe the generation capacity of Power Stations and/or Generating Units. Arguably, the most common of these are:

Declared Net Capability (DNC);
Registered Capacity (RC);
Transmission Entry Capacity (TEC); and
Connection Entry Capacity (CEC).

Each of the above terms carries a different meaning; some differences are slight whilst others are significant. Definitions or ‘descriptions’ of these terms are included in the Glossary to this Statement. As a consequence of their different meanings, some are more appropriate for certain uses than others. The following paragraphs provide an outline description of each and summarise how each has been used for the purposes of this Statement.

Declared Net Capability (DNC)

The term DNC is essentially a pre-vesting term. It is no longer used by NGET but, until 2004, was still used by the two Scottish Transmission Licensees (i.e. SPT and SHETL) in their Seven Year Statements. It may be noted that the definition given in the Glossary, which mirrors the definition given in the 2004 SPT SYS, does not define "Generator", although this can be taken to mean either a generating unit or a power station. Nor does that definition define "Auxiliary load" or "site demand", although these may be taken to carry the same meaning

The term DNC is often used to describe the level of electricity sourced from renewable fuels, since the term takes the intermittent nature of the power output from some renewable sources into account. For wind this is 43% of its gross capacity.

Finally, whilst reference may be made to DNC in parts of this Statement, the term is not otherwise used.

Registered Capacity (RC)

The term RC was introduced at vesting and has been in use in England and Wales since then. Its definition has developed over the years and is given in various documents, the most notable of which are the Grid Code (GC) and the Licence Standard. The value of the term has been used in the setting of regulatory, licence and Grid Code requirements. For example, the size of Power Station in terms of RC classifies the station as Small, Medium or Large. That classification, in turn, determines whether the particular plant requires a licence and/or which parts of the Grid Code must be complied with. The current definition is given in the Glossary.

Whilst the definition of RC has been developed over the years since vesting, it is nevertheless very similar in effect to the less rigorous pre-vesting term and definition of DNC used by the Scottish Transmission Licensees. The terms and values of DNC and RC have all been used by the various parties over the years in:

- the application of the Licence Standard, transmission infrastructure planning and transmission connection planning;
- defining the size of a Power Station for regulatory, GC compliance and other purposes (e.g. Large, Medium and Small Power Stations);
- evaluating Plant Margins; and
- charging purposes (e.g. setting Transmission Network Use of System charges).

The following provides a quick reference summary of the key properties of RC and its usage within this Statement:

- RC and CEC are both on a unit basis and are broadly synonymous
- The License Standard is currently written in terms of Registered Capacity
- " In cases where a unit value of generation capacity is required, and given that there is no unit value for TEC, RC may be judiciously used. An example would be when compiling a Ranking Order. However, even in this case, the maximum output of each Power Station should not exceed the TEC. That methodology, which is described **Modelling of the Planned Transfer**, requires inputs relating to both RC and TEC. The Ranking Order is a basis for system analyses.

Transmission Entry Capacity (TEC)

The relatively new terms of TEC and CEC were first introduced under the ‘New Electricity Trading arrangements’ (NETA), which were applied in England and Wales. The terms continue to be used under the ‘British Electricity Trading and Transmission Arrangements’ (BETTA), which were introduced in 2005 to replace NETA and are applied to the whole of the GB transmission system. In essence, TEC reflects the maximum power the user can export across the GB transmission system away from the connection site. TEC is defined on a station basis only and cannot exceed station CEC. In the GB Grid Code, TEC is defined by reference to the meaning set out in the Connection and Use of System Agreement. This avoids the need to amend the GC when the value of TEC is changed for whatever reason. The Glossary includes an informal description of TEC, which has been written for the purpose of this Statement. The Glossary description is not intended as a formal definition and equivalent descriptions and definitions in other documentation may differ slightly.

Inspection of the description of TEC included in the Glossary section of this Statement reveals that it differs from the Grid Code definition of RC in two respects. First, TEC is solely on a Power Station basis and does not exist on a Generating Unit or CCGT Module basis. Second, the value of TEC represents the net "spill" onto the GB transmission system from the Power Station. Accordingly, any auxiliary demand supplied through the station transformers is netted off the gross station output to give the net "spill".

TEC cannot be greater than Power Station CEC but can be lower since: first, TEC is net of any auxiliary demand supplied through the station transformers; and second, the actual value of TEC can be set for commercial reasons at any lower level. TEC is a commercial term and its value is given in the relevant bilateral agreement.

The following provides a quick reference summary of the key properties of TEC and its usage within this Statement:

- TEC reflects the maximum power the Generator can export across the system from the Grid Entry Point or User System Entry Point.
- The level of use of system rights for a power station is expressed in terms of the amount of TEC that has been purchased by the Generator for that power station.
- Transmission infrastructure is designed on the basis of TEC.
- It may be noted that RC rather than TEC is currently used in the GB Transmission System Security and Quality of Supply Standard (License Standard). However, given the similarity between the definitions as discussed above, there is no difference in effect, providing that caution is exercised in relation to the appropriate system demand used. That is, if TEC is used in place of RC then the auxiliary demand supplied through the station transformers should be netted off the "GB Transmission System Demand".
- TEC is the main generation capacity term/value used in this 2009 GB SYS.
- The value of TEC is used for power system analyses and plant margin calculation etc.

Connection Entry Capacity (CEC)

As previously mentioned, the term CEC was first introduced, along with the term TEC, under NETA. In essence, CEC is used on both a Generating Unit and Power Station basis. CEC may be regarded as the maximum power that a user may export onto the GB transmission system at the connection site. As with TEC, the GC defines CEC by reference to the meaning set out in the Connection and Use of System Agreement. As previously explained, this avoids the need to amend the GC when the value of CEC is changed for whatever reason. The Glossary includes an informal description of CEC, which has been written for the purpose of this Statement. As with the Glossary description of TEC, the Glossary description of CEC is not intended as a formal definition and equivalent descriptions and definitions in other documentation may differ slightly.

The Glossary description of CEC is in three parts. For each part, i.e. (a) in relation to a Generating Unit, (b) in relation to a CCGT Module and (c) in relation to a Power Station, the relevant value of CEC is written into the bilateral connection agreement.

In the case of (a), the Generating Unit CEC is used as a basis for the design of a new or modified connection. In the case of (c), the Power Station CEC is normally the sum of the individual Generating Unit CECs. A Generator may choose to declare a Power Station CEC, which is lower (but not higher) than the summation of individual Generating Unit CECs, in which case this lower value is written into the bilateral connection agreement.

Inspection of the Glossary description of CEC reveals that it is almost identical to the GC definition of RC and the two may be regarded as being broadly synonymous. The only difference lies in the fact that, on the one hand CEC may include "Maxgen" capability or alternatively it may include a restricted output due to a technical difficulty. RC, on the other hand, is written in terms of "normal full load Capacity". CEC may be regarded as setting the ceiling value on RC.

As mentioned previously, TEC cannot be greater than power station CEC but can be lower.

The following provides a quick reference summary of the key properties of CEC and its usage within this Statement:

- CEC reflects the maximum power for which the Grid Entry Point or User System entry Point should be designed.
- CEC values have been used in the allocation of connection assets in the charge setting process but with the introduction of "PLUGS" this practise ceases. "PLUGS" is the charging methodology, which was introduced in England & Wales on 1 April 2004 and in Scotland on 30 November 2004.
- The Grid Entry Point is designed on the basis of CEC
- It may be stressed that RC rather than CEC is currently used in the License Standard. However, given the similarity between definitions, there is no difference in effect.
- CEC is referred to and displayed in the various tables of this Statement where appropriate. However, CEC is not be used in the power system analyses.

Finally, as a related point of interest, PC.4.3.1 of the Grid Code states that, "…NGET will also use the Transmission Entry Capacity and Connection Entry Capacity in the preparation of the Seven Year Statement and to that extent the data will not be treated as confidential".

Large, Medium and Small Power Stations

The GB Grid Code places different requirements on different classes of generating plant. The three main power station classifications are Large Power Station, Medium Power Station and Small Power Station and the Grid Code defines these on the basis of Registered Capacity. The relevant definitions are included in the Glossary section of this Statement. Inspection reveals that the definitions vary according to whether the power station is located on the NGET system, on the SPT system or on the SHETL system. **Table 3.1** summarises the differences.

Notwithstanding the fact that the GB Grid Code classifies power stations in terms of their Registered Capacity, for the intents and purposes of this Statement, Power Stations may be taken to be classified and defined in terms of power station Transmission Entry Capacity (TEC).

Bilateral Agreements

The definition included in the Glossary of this Statement identifies three types of Bilateral Connection Agreement, namely a Bilateral Connection Agreement (BCA); a Bilateral Embedded Generation Agreement (BEGA); and a Bilateral Embedded Licence Exemptable Large Power Station Agreement (BELLA). Power station projects where these agreements are in place are, as explained in the Glossary, defined as "Transmission Contracted".

Please note, however, that whether "Transmission Contracted" or not, the Distribution Network Operators net off what they deem to be an appropriate allowance for the output from embedded Medium and Small power stations from their week 24 Grid Code demand submissions. Accordingly, such power stations are not detailed in this chapter.

Figure 10.5 of Chapter 10 describes the relationships between the different types of Bilateral Agreement, the power station type, the connection type, the power station output terminology and the appropriate charges.

Bilateral Connection Agreement (BCA)

A BCA is for directly connected power stations (regardless of whether they are classified as Large, Medium or Small), directly connected Distribution Systems, Non-Embedded Customers and directly connected Interconnectors.

A User with a BCA pays for both connection to the GB transmission system and for use of the GB transmission system.

A power station covered by a BCA will have both TEC and CEC values.

Bilateral Embedded Generation Agreement (BEGA)

A BEGA, amongst other things, relates to use of the GB transmission system by embedded power stations (which are not License exempt), small power station trading parties and distribution interconnector owners. An embedded power station covered by a BELLA (see below) is not included, as a BELLA relates to Licence exempt embedded Large power stations.

A User with a BEGA does not have a connection to the GB transmission system and, in consequence, does not pay connection charges relating to the GB transmission system. The User does however use the GB transmission system and therefore pays appropriate use of system charges.

A power station covered by a BEGA does not have a CEC since the term CEC relates to the connection assets to the GB transmission system of which there are none. However, a BEGA power station does have a TEC for the purpose of use of the GB transmission system.

Bilateral Embedded Licence Exemptable Large Power Station Agreement (BELLA)

A BELLA is for embedded Large power stations, which are Licence exempt and which are registered either in the SMRS (Supply Metering Registration System) or in the CMRS (Central Metering Registration System) by a User (e.g. host User) who is responsible for the transmission use of system charges relating to the GB transmission system associated with the Balancing Mechanism (BM) Unit registered in CMRS.

A power station covered by a BELLA does not have a connection to the GB transmission system and in consequence does not pay connection charges relating to the GB transmission system. Nor does the power station 'directly' use the GB transmission system since this is via the User referred to above who is responsible for transmission use of system charges associated with the CMRS registered BM Unit. Accordingly a BELLA power station does not pay GB transmission use of system charges. However, payments may change hands between the power station and the User in relation to reduced demand, use of the distribution system etc.

A power station covered by a BELLA has neither a TEC nor a CEC. The output of the power station is described in Appendix A of the BELLA by the term 'Size of Power Station'.

Licence Exempt Generation Agreement (LEGA)

There used to be a fourth type of Bilateral Agreement, namely: a LEGA. While the LEGA was phased out in 2006, it is mentioned here for completeness. The LEGA was for power stations capable of exporting between 50MW and 100MW to the total system (i.e. embedded Medium power stations in England and Wales) connecting since 30 September 2000. Such generators could apply to the DTI to seek Licence Exemption. The DTI would then consult all interested parties including National Grid. On receipt of the DTI consultation documents we would consider the need for:

- any transmission system works including timing;
- Grid Code data requirements (e.g. Planning Code data);
- technical requirements (e.g. as specified under the Grid Code Connection Conditions);
- metering requirements

The above information would then be included in our response to the DTI consultation document and at the same time we would offer a Licence Exempt Generation Agreement with the Generator, also containing the above information, where appropriate. The Bilateral Agreements did not automatically subject the Generator to TNUoS charges, but would provide for any necessary data exchange.

A LEGA was, by definition, a Medium power station. In submitting the Week 24 Grid Code demand submissions, the Distribution Network Operator would, as with other embedded Medium power stations, net off his allowance for the output of a LEGA.

Licence exempt embedded Large (rather than Medium) power stations were, and continue to be, covered by a BELLA (rather than a LEGA).

Transmission System Access

Access to the GB transmission system is provided through arrangements with National Grid, acting as GBSO, under the Connection and Use of System Code (CUSC). The CUSC sets out the contractual framework for connection to, and use of, the GB transmission system. The CUSC has applied across the whole of Great Britain since BETTA "go-live" (1 April 2005).

All applications for connection to, or use of, the GB transmission system are routed through National Grid as GBSO. On receipt of an application for connection to, or use of, the NGET system in England and Wales, NGET prepare a Transmission Owner Reinforcement Instruction (TORI) and elements of this are used by NGET in making an appropriate Offer to the customer. On receipt of an application to connect to, or use, one of the networks owned by a Scottish Transmission Owner (i.e. SHETL or SPT), NGET copy the application to the relevant TO who prepares a Transmission Owner Construction Agreement (TOCA). NGET then make an appropriate Offer to the customer on the basis of both the TORI and TOCA. Amongst other things, the TOCA would include, transmission works, User works, dates and construction programme. A TOCA is only relevant for connections to the Scottish networks. When the Offer is agreed and signed, the project becomes 'Transmission Contracted' and the relevant Scottish TO proceeds with construction in accordance with the TOCA.

The process for obtaining access to the GB Transmission system is currently under review, details of which can be found in chapter 9.

Figure 3.1 - Changes in Generation Capacity, 2005/06 to 2015/16

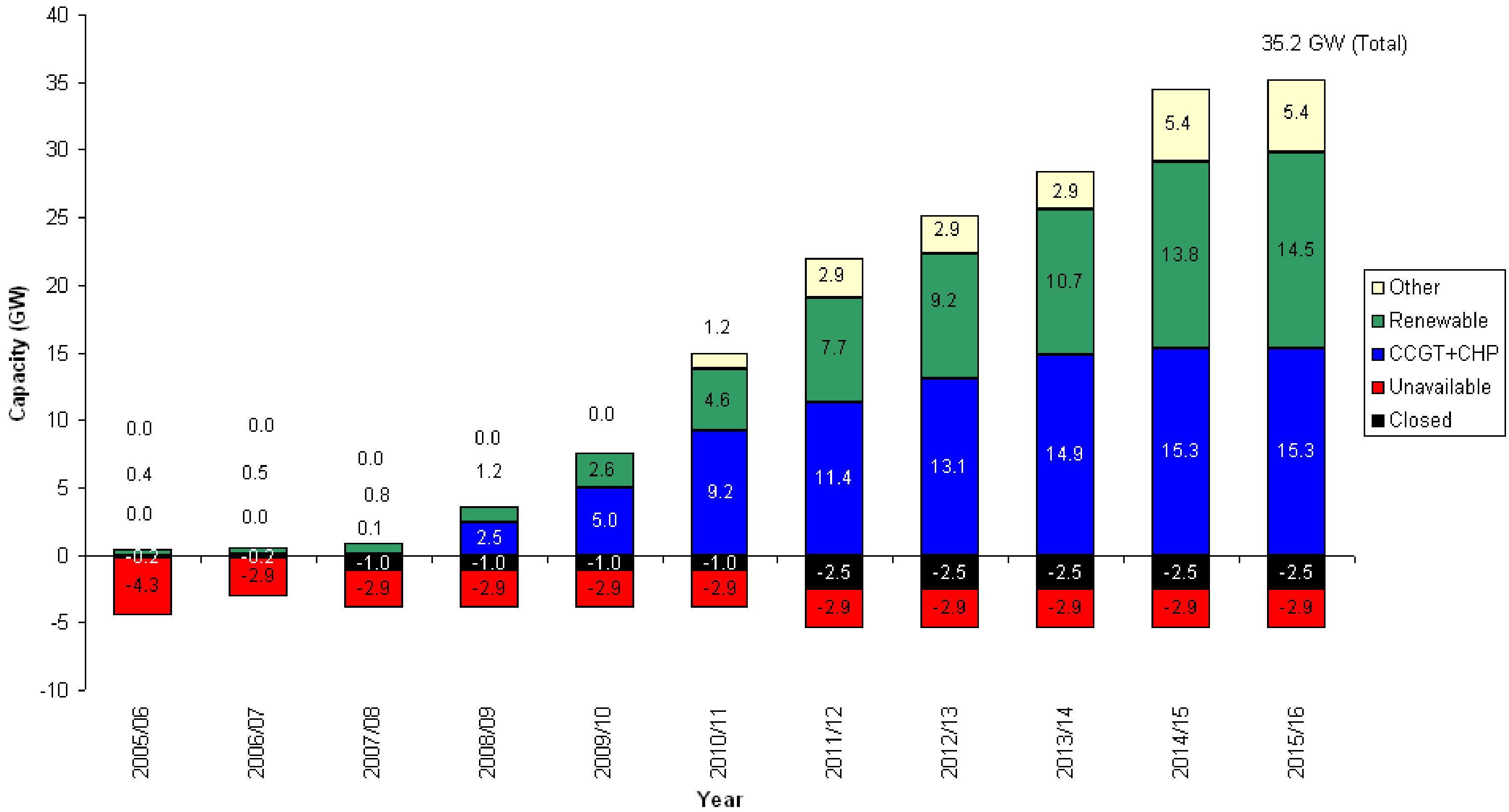


Figure 3.2 - Existing and Planned Transmission Contracted Generation

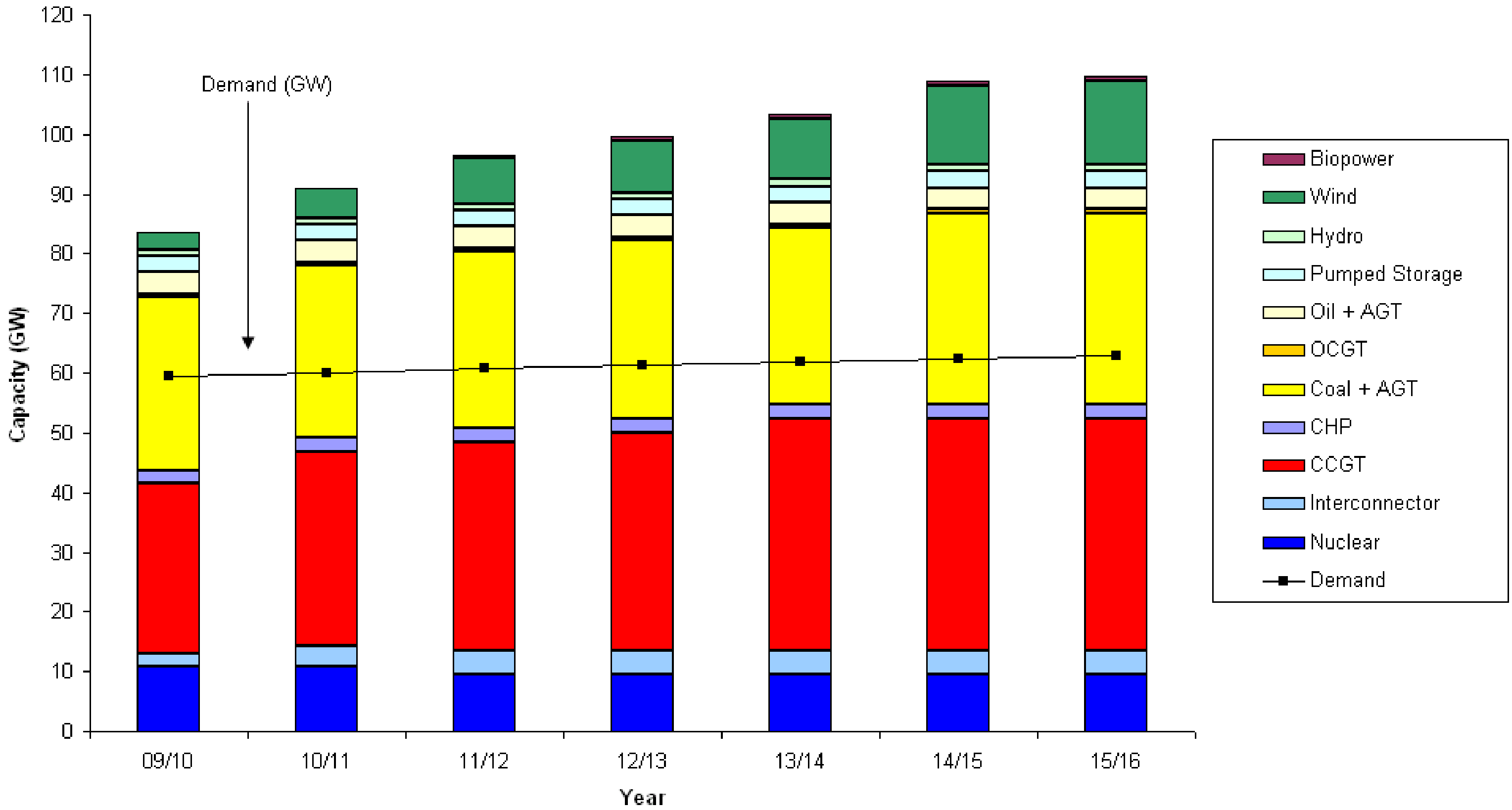


Figure 3.3a - Key for Figure 3.3b - 3.3f

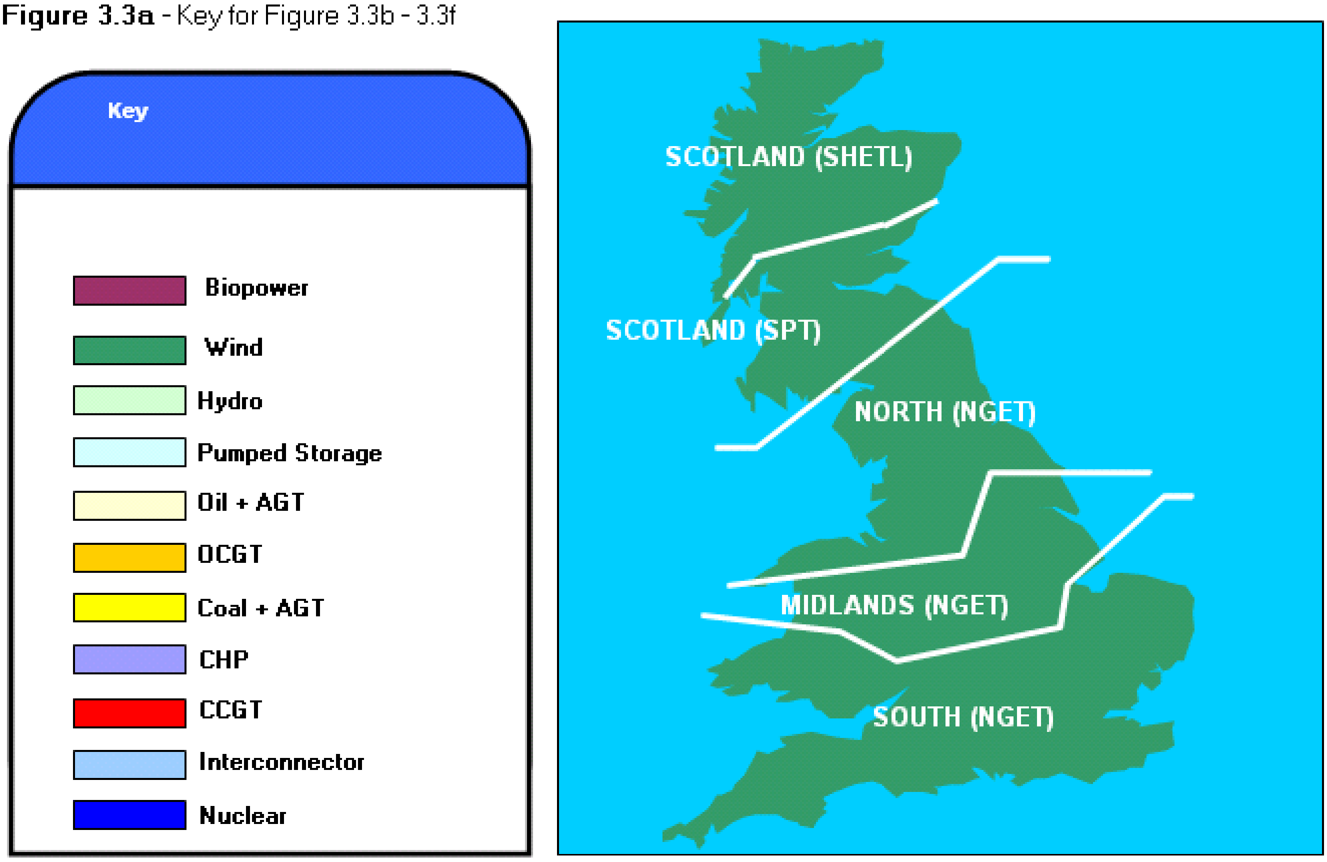


Figure 3.3b - Plant Type by Zone (SHETL), 2009/10 to 2015/16

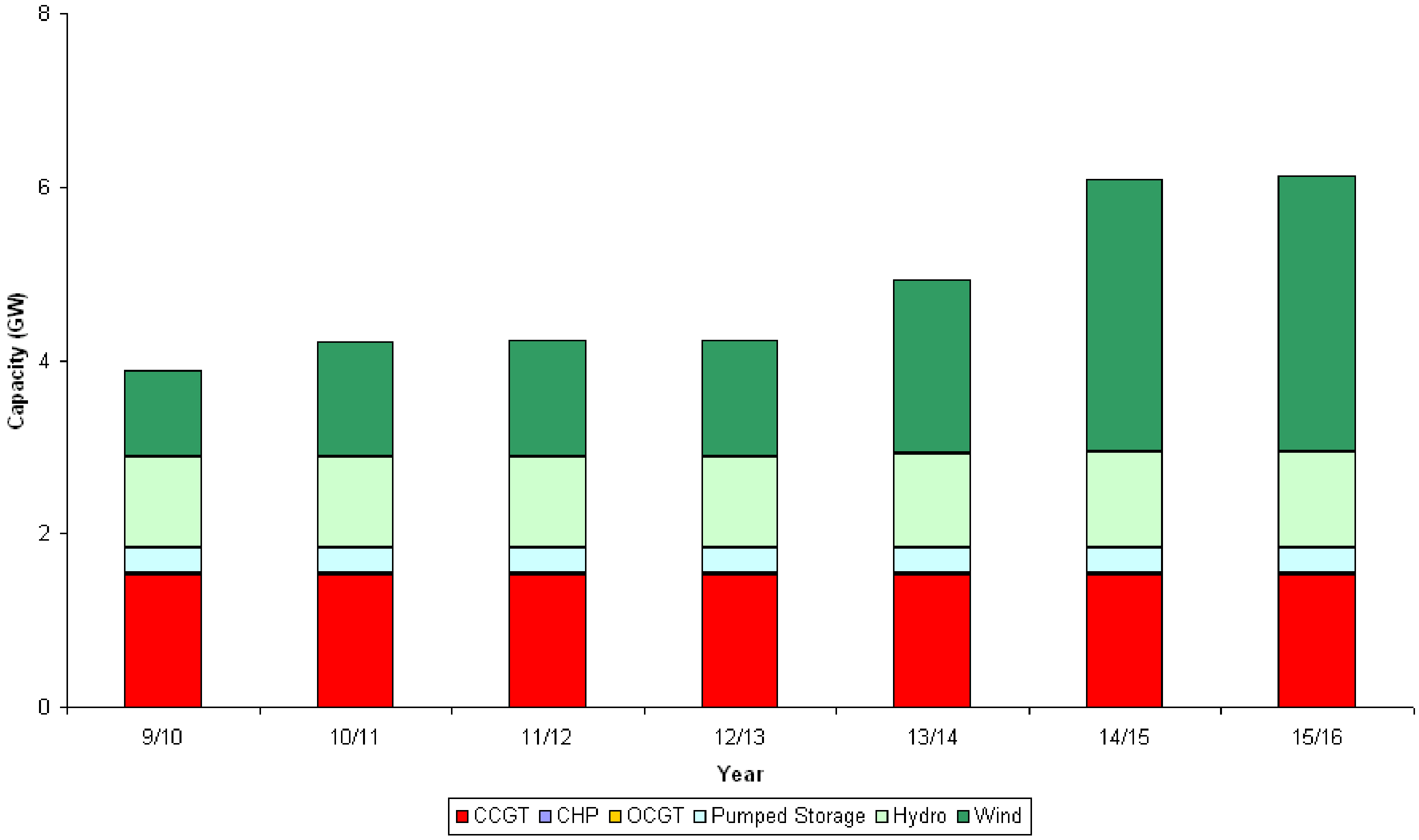


Figure 3.3c - Plant Type by Zone (SPT), 2009/10 to 2015/16

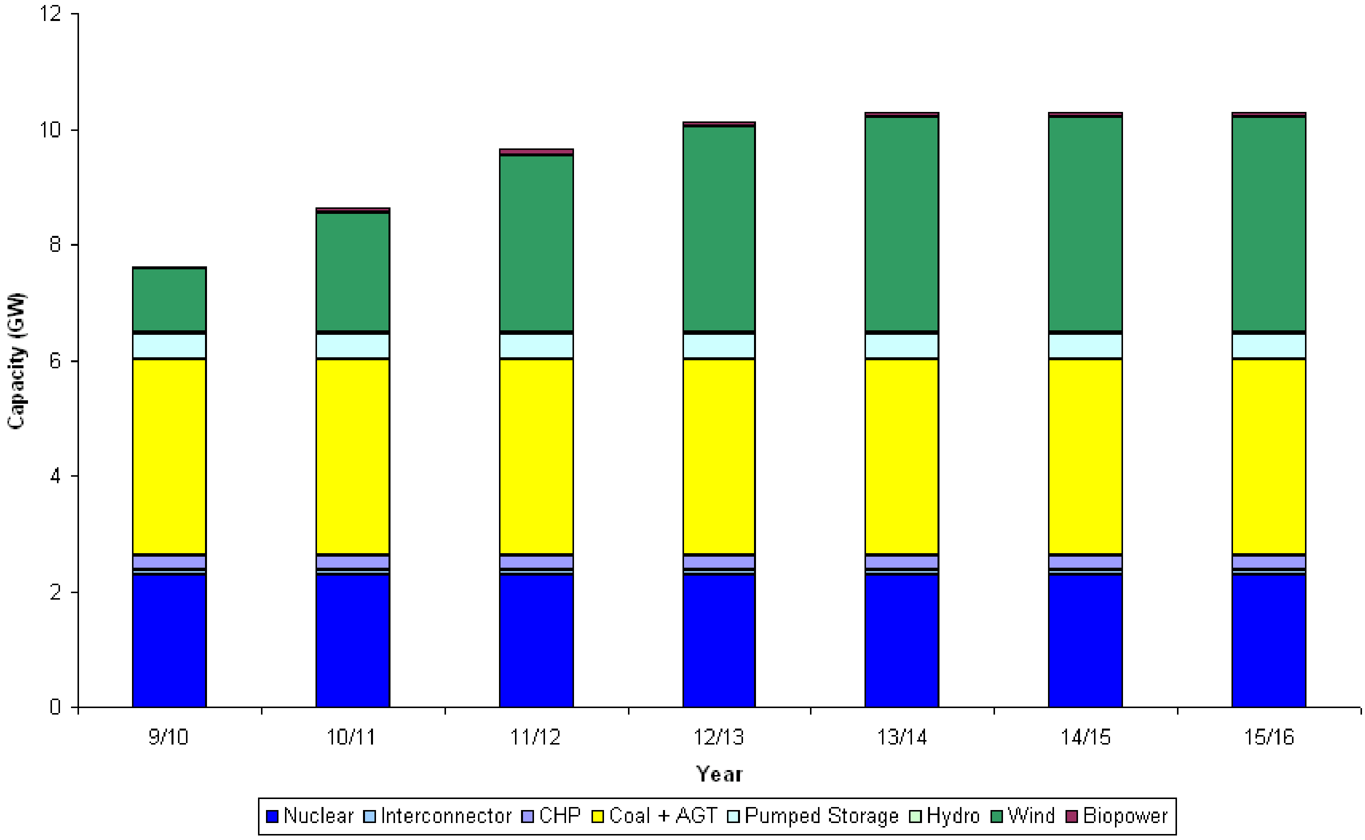
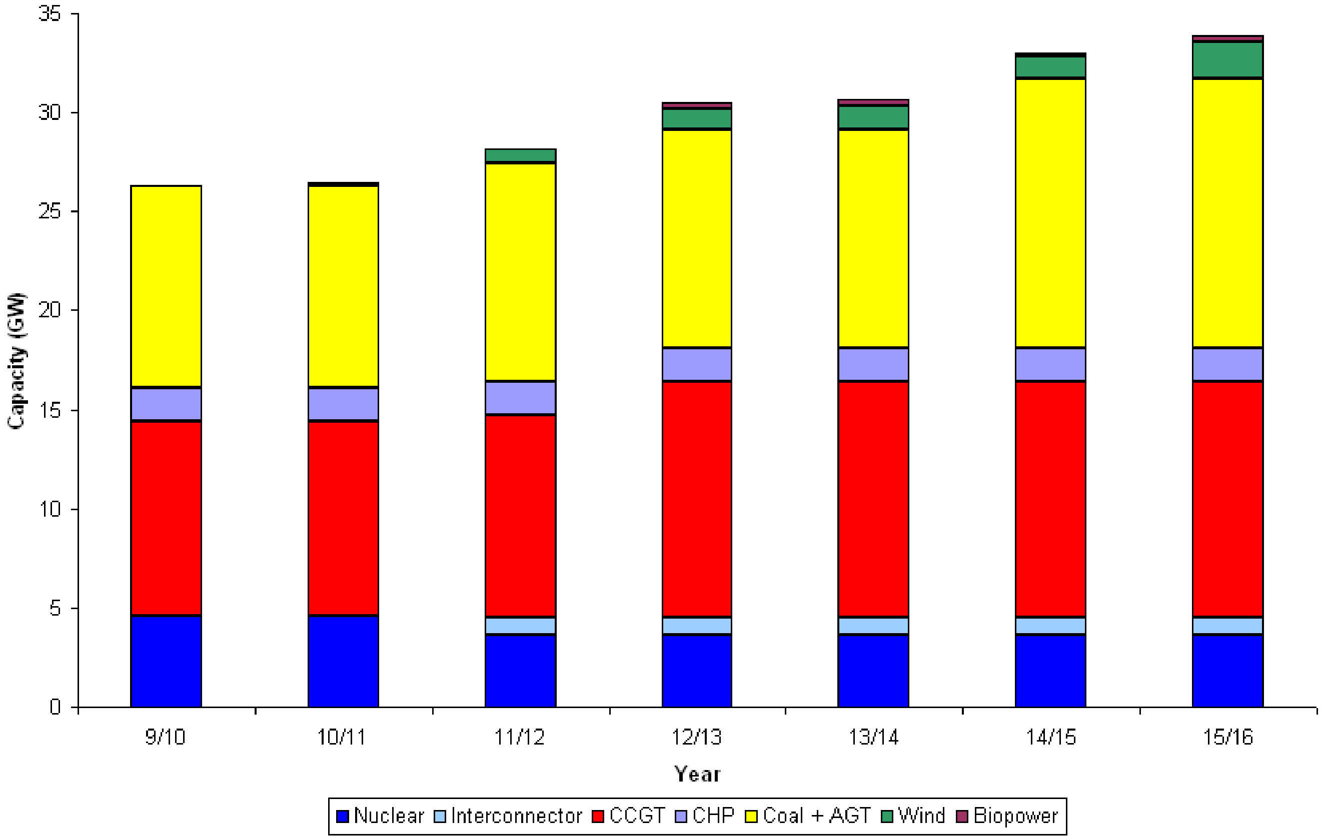


Figure 3.3d - Plant Type by Zone (North), 2009/10 to 2015/16



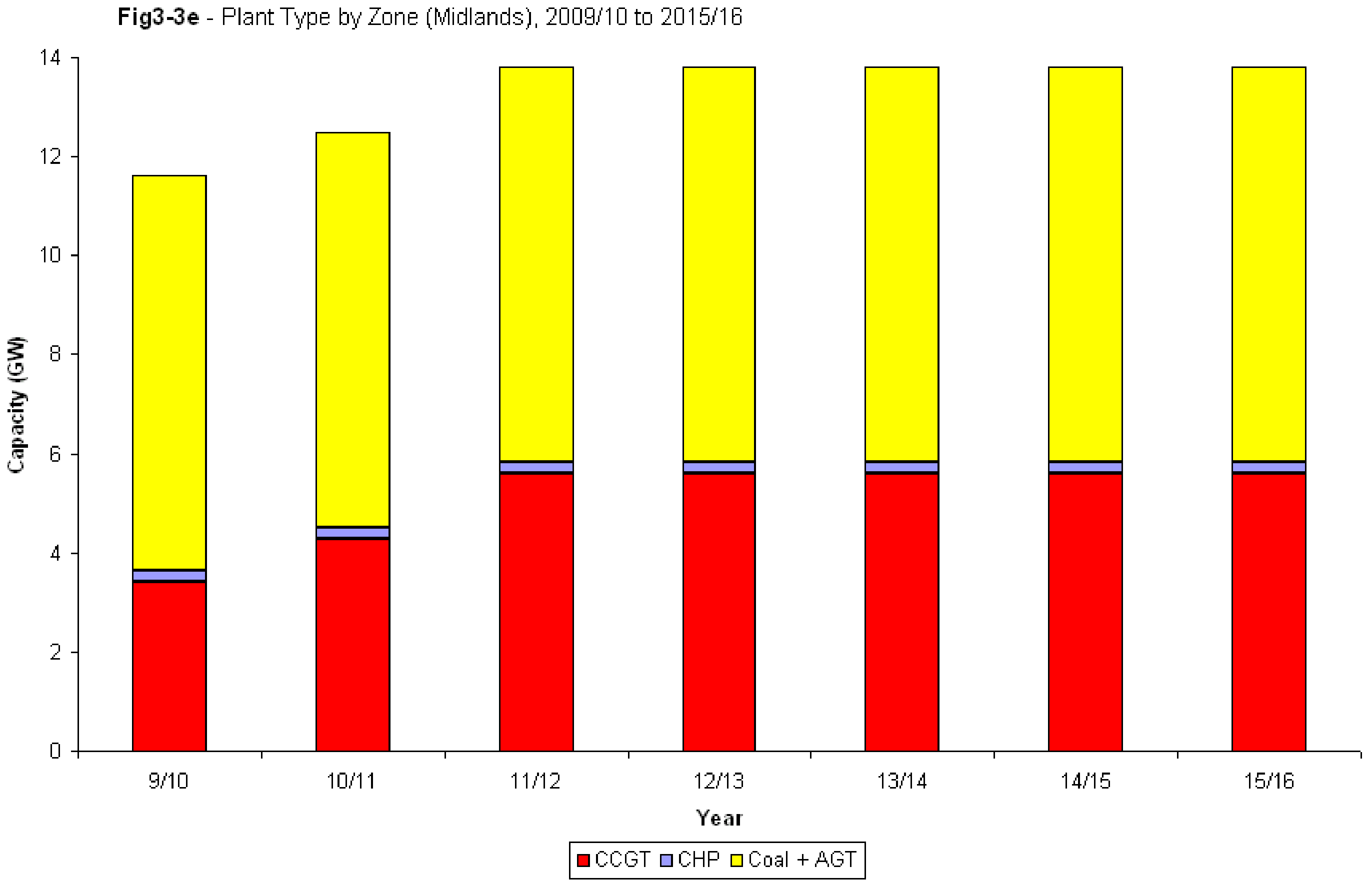


Fig3-3e - Plant Type by Zone (Midlands), 2009/10 to 2015/16
Capacity (GW)
0
2
4
6
8
10
12
14
9/10
10/11
11/12
12/13
13/14
14/15
15/16
Year
CCGT
CHP
Coal + AGT

Figure 3.3f - Plant Type by Zone (South), 2009/10 to 2015/16

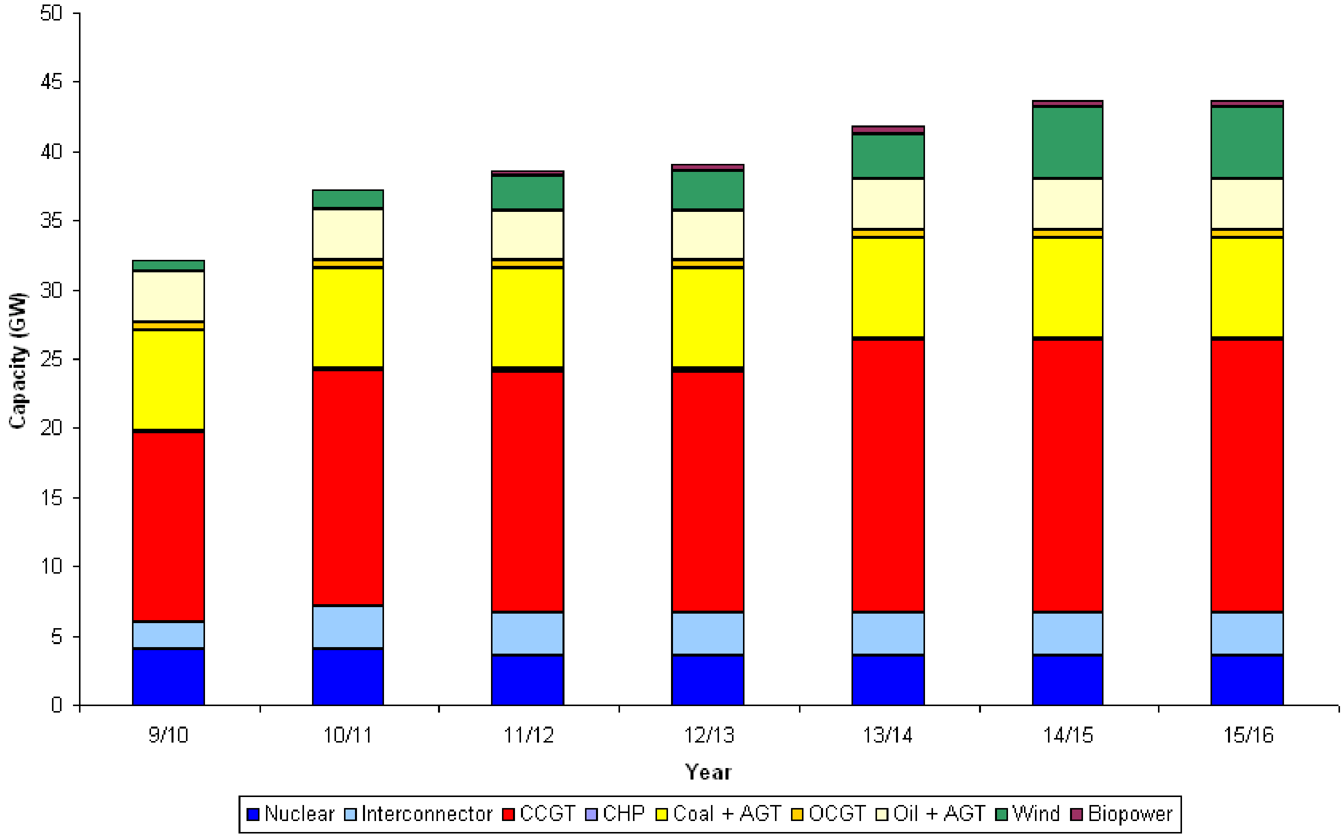


Figure 3.5 - Disposition of New Generation Capacity, 2005/06 to 2015/06

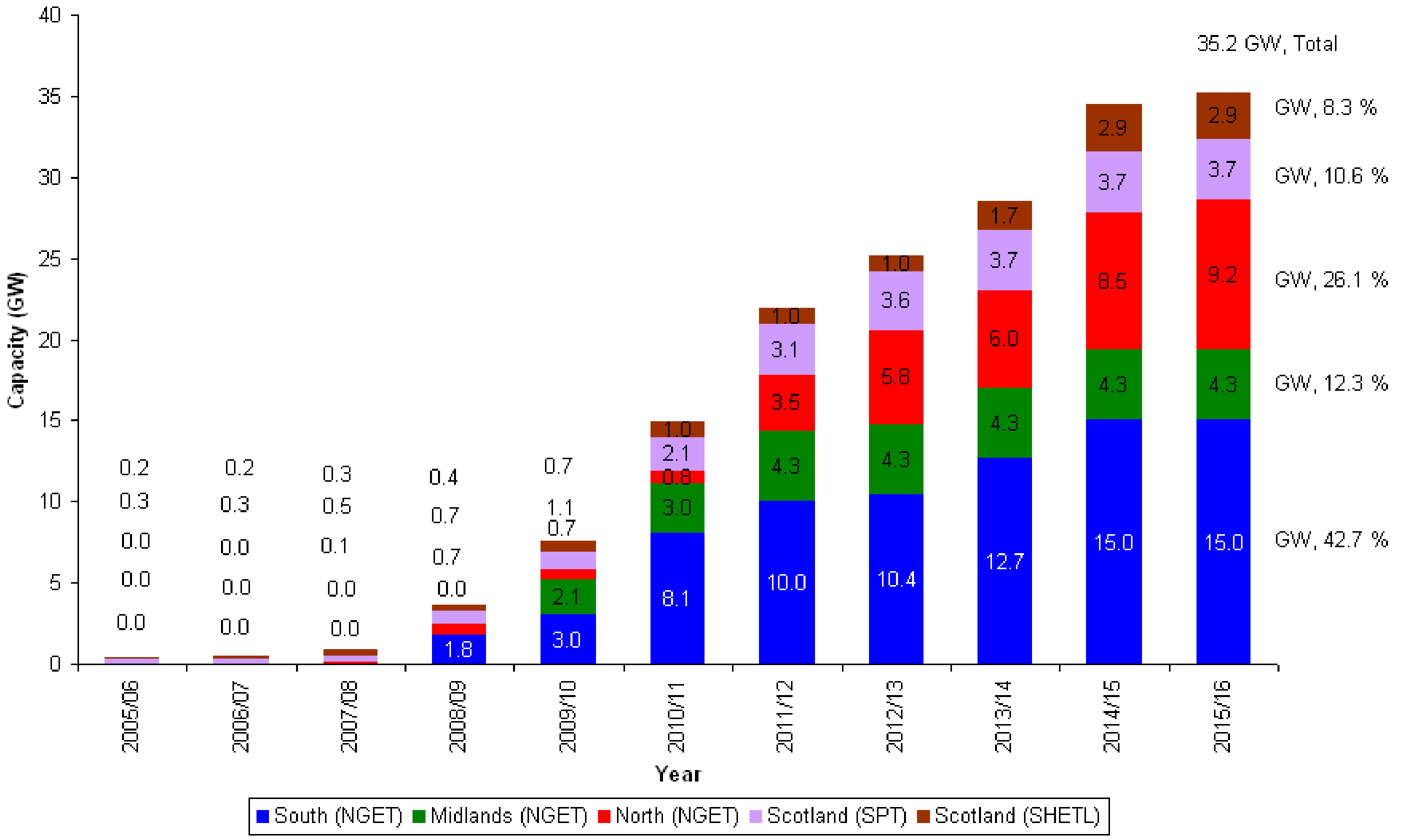


Figure 3.4 - Total Installed Generation Disposition (GW)

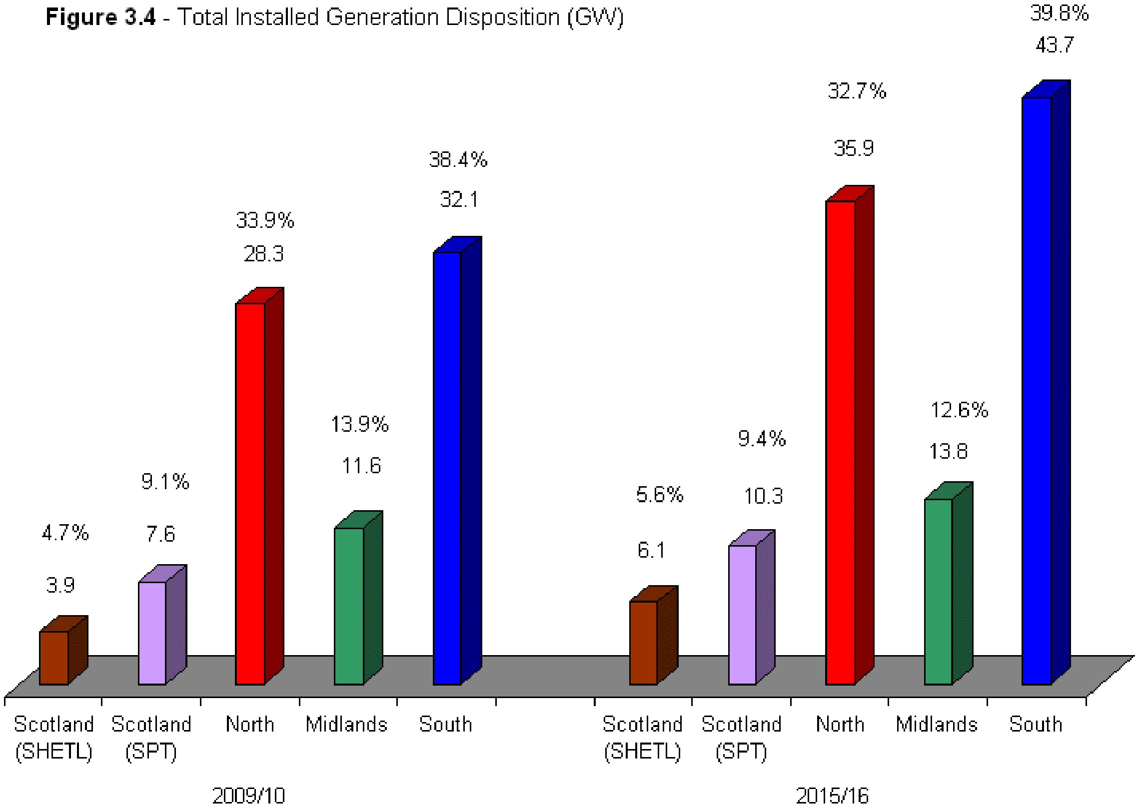


Figure 3.6 - GB Zonal Plant/Demand Balance - Installed Generation

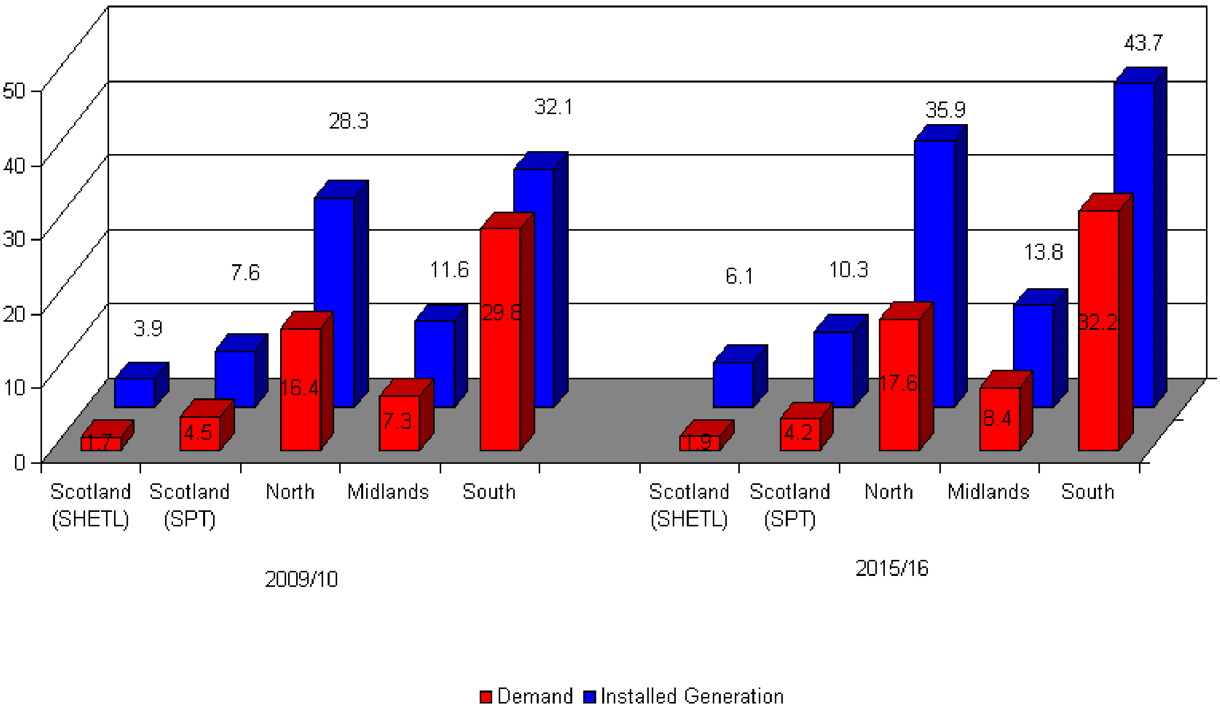


Figure 3.7 - GB Zonal Plant/Demand Balance - Studied Generation

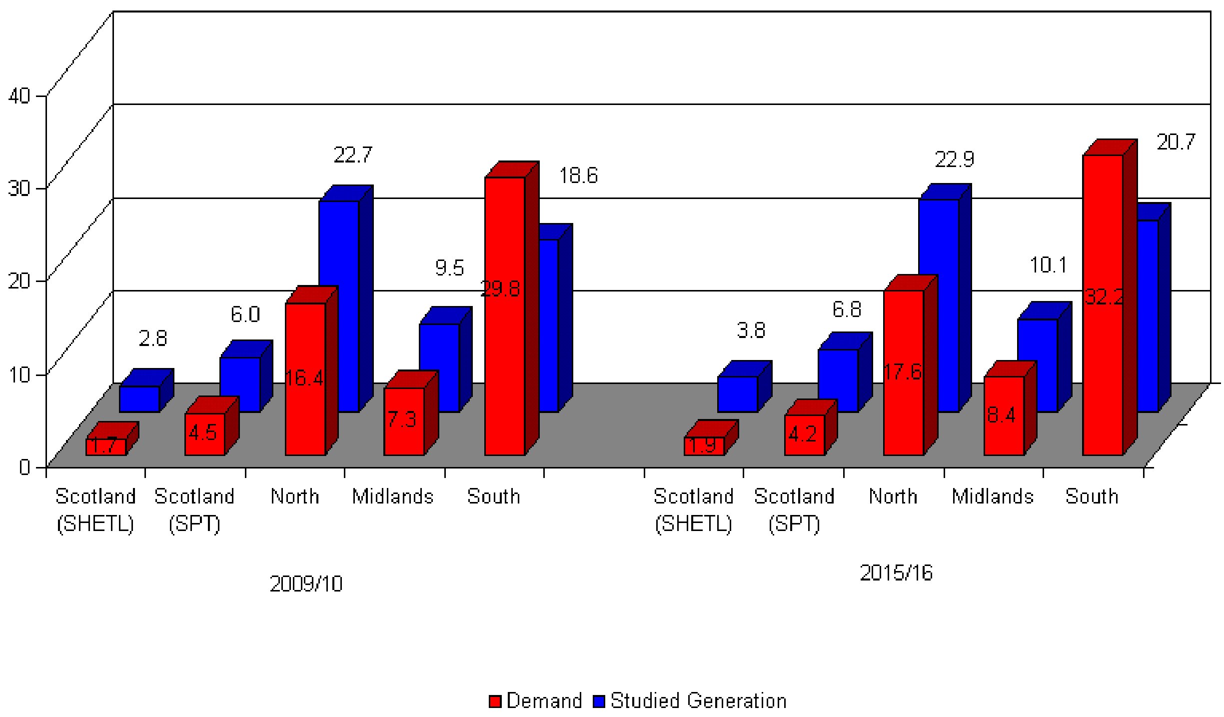


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Table 3.1 - Power Station Classification by Registered Capacity (MW)

Class	NGET	SPT	SHETL
Large	100 or more	30 or more	10 or more
Medium	50 or more but less than 100	Unclasified	Unclasified
Small	Less than 50	Less than 30	Less than 10

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Table 3.2 - Generation Projects Under Construction

Licensee	Power Station	Owner	Plant Type	New Capacity (MW)	Year	Source
NGET	Severn Power Stage 1	Severn Power Ltd	CCGT	425	2009	NGET
NGET	Staythorpe C Stage 1	RWE Npower plc	CCGT	425	2009	NGET
NGET	Staythorpe C Stage 2	RWE Npower plc	CCGT	425	2009	NGET
NGET	Staythorpe C Stage 3	RWE Npower plc	CCGT	850	2009	NGET
NGET	West Burton B Stage 1	West Burton Limited	CCGT	435	2009	NGET
NGET	Grain Stage 2	E.ON UK plc	CCGT	860	2010	NGET
NGET	Severn Power Stage 2	Severn Power Ltd	CCGT	425	2010	NGET
NGET	West Burton B Stage 2	West Burton Limited	CCGT	435	2010	NGET
NGET	West Burton B Stage 3	West Burton Limited	CCGT	435	2010	NGET
NGET	Grain Stage 3	E.ON UK plc	CCGT	430	2011	NGET
NGET	Netherlands Interconnector Stage 1	BritNed Development Ltd	Interconnector	0	2009	NGET
NGET	Netherlands Interconnector Stage 2	BritNed Development Ltd	Interconnector	800	2010	NGET
NGET	Netherlands Interconnector Stage 3	BritNed Development Ltd	Interconnector	400	2010	NGET
NGET	Thanet	Thanet Offshore Wind Ltd	Offshore Wind	300	2009	BWEA
NGET	Greater Gabbard	Greater Gabbard Offshore Winds Ltd	Offshore Wind	500	2009	NGET
SPT	Crystal Rig 2	Fred Olsen Renewables Ltd	Onshore Wind	200	2009	BWEA
SPT	Dun Law extension	CRE Energy Ltd	Onshore Wind	30	2009	BWEA
SPT	Longpark	Wind Prospect Ltd	Onshore Wind	38	2009	BWEA
SPT	Whitelee Stage 3	CRE Energy Ltd	Onshore Wind	29	2009	NGET
SPT	Toddleburn	I & H Brown Toddleburn Ltd	Onshore Wind	36	2009	NGET
SPT	Clyde	Airtricity Developments (Scotland) Ltd	Onshore Wind	519	2010	NGET
SHETL	Glendoe, Fort Augustus Stage 2	SSE Generation Ltd	Hydro	48	2013	NGET
SHETL	Fasnakyle Compensation Hydro (Unit 4)	SSE Generation Ltd	Hydro	8	2014	NGET
SHETL	Edinbane Wind, Skye	AMEC Wind Energy Ltd	Onshore Wind	42	2009	BWEA

SHETL	Kilbraur (Strath Brora) Wind Farm Stage 2	Kilbraur Wind Energy Ltd	Onshore Wind	20	2009	BWEA
SHETL	Millenium Wind, Ceannacroc Stage 3	Millenium Wind Energy Ltd	Onshore Wind	15	2009	BWEA
SHETL	Tullo Wind Farm, Laurencekirk	Tullo Wind Farm Ltd	Onshore Wind	14	2009	BWEA
SHETL	Beinn an Turic 2	CRE Energy Ltd	Onshore Wind	38	2010	BWEA
SHETL	Gordonbush Wind	SSE Generation Ltd	Onshore Wind	70	2009	NGET

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Table 3.3 - Generation Projects with Consents Granted

Licensee	Power Station	Owner	Plant Type	New Capacity (MW)	Year	Source
SPT	Arecleoch	CRE Energy Ltd	Onshore Wind	150	2010	NGET
NGET	Barking C	Barking Power Ltd	CCGT	470	2013	NGET
NGET	Brine Field	Thor Cogeneration Ltd	CCGT	1020	2012	DECC
SPT	Brockloch Rig	Brockloch Rig Windfarm Ltd	Onshore Wind	60	2012	NGET
SHETL	Carraig Gheal (Fernoch)	Greenpower (Carraig Gheal) Ltd	Onshore Wind	60	2010	NGET
SHETL	Causeymire Phase 2	Causeymire Windfarm Ltd	Onshore Wind	7	2011	NGET
NGET	Drakelow D	E.ON UK plc	CCGT	1320	2011	NGET
SPT	Drone Hill	PM Renewables Ltd	Onshore Wind	38	2010	NGET
SHETL	Fairburn Wind Farm	SSE Generation Ltd	Onshore Wind	40	2009	NGET
SHETL	Griffin Windfarm	GreenPower (Griffin) Ltd	Onshore Wind	204	2010	NGET
SPT	Harestanes	CRE Energy Ltd	Onshore Wind	140	2011	NGET
NGET	Heysham Offshore Wind Farm	Heysham Offshore Wind Ltd	Offshore Wind	140	2010	NGET
SHETL	Lairg - Achany Wind Farm	SSE Generation Ltd	Onshore Wind	50	2009	NGET
NGET	Lincs Offshore Wind Farm	Offshore Windpower Ltd	Offshore Wind	250	2010	NGET
SPT	Mark's Hill	Catamount Energy Ltd	Onshore Wind	99	2010	NGET
SHETL	Novar 2 Wind Farm, Alness	Novar 2 Wind Farm Ltd	Onshore Wind	32	2014	NGET
NGET	Partington Stage 1	Bridestones Developments Ltd	CCGT	430	2011	NGET
NGET	Partington Stage 2	Bridestones Developments Ltd	CCGT	430	2012	NGET
NGET	Port Talbot	Prenergy Power Ltd	Woodchip	350	2011	NGET
SHETL	Rosehall, Shin	E.ON UK Renewables Ltd	Onshore Wind	29		NGET
NGET	Sheringham Shoal	Scira Offshore Energy Ltd	Offshore Wind	315	2010	NGET
SPT	Tormywheel	PM Renewables Ltd	Onshore Wind	32	2010	NGET
SPT	Whiteside Hill	Airtricity Developments (Scotland) Ltd	Onshore Wind	27	2012	NGET

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Table 3.4 - Generation Commissioning Date Assumptions

Station Name	Licensee	Commissioning Year	Plant Type	TEC (MW)	Contract Date	S36 Status	S36 Date	S14 Status	S14 Date
none									

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Table 3.5 - Power Station Transmission Entry Capacities for 2009/10 to 2015/16 (MW)

Licensee	Plant Type	Power Station	Owner	2009/10 Capacity (MW)	2010/11 Capacity (MW)	2011/12 Capacity (MW)	2012/13 Capacity (MW)	2013/14 Capacity (MW)	2014/15 Capacity (MW)	2015/16 Capacity (MW)	SYS Study Zone	TEC	Size of Power Station	CEC	Tariff Zone	Type of Bilateral Agreement	DCLF Node
NGET	Biomass	Portbury	E.ON Climate & Renewables UK Operations Ltd	0	0	0	150	150	150	150	Z13	Yes			15	BEGA	
NGET	Biomass	Tees Renewable Energy Plant	Prenergy Power Ltd	0	0	0	299	299	100	299	Z7	Yes		299	10	BCA	
NGET	CCGT	Amlwch	Canatxx Energy Ventures Ltd	0	0	0	270	270	270	270	Z9	Yes		299	11	BCA	AMLW40
NGET	CCGT	Baglan Bay 1	Baglan Generating Ltd & Baglan Operations Ltd	552	552	552	552	552	552	552	Z13	Yes		552	15	BCA	BAGB20
NGET	CCGT	Baglan Bay 2 Stage 1	Abernedd Power Company Ltd	0	0	0	0	435	435	435	Z13	Yes		435	15	BCA	
NGET	CCGT	Barking	Barking Power Ltd	1000	1000	1000	1000	1000	1000	1000	Z14	Yes		1000	17	BCA	BARK20_LPN
NGET	CCGT	Barking C	Barking Power Ltd	0	0	0	0	470	470	470	Z14	Yes		470	17	BCA	BARK20_LPN
NGET	CCGT	Barry	Centrica Barry Ltd	245	245	245	245	245	245	245	Z13	Yes			15	BEGA	CARE20
NGET	CCGT	Brigg	Regional Power Generators Ltd	260	260	260	260	260	260	260	Z8	Yes			13	BEGA	KEAD40
NGET	CCGT	Brine Field	Thor Cogeneration Ltd	0	0	0	1020	1020	1020	1020	Z7	Yes		1020	10	BCA	
NGET	CCGT	CDCL	E.ON UK plc	395	395	395	395	395	395	395	Z10	Yes		440	13	BCA	COTT40
NGET	CCGT	Connahs Quay	E.ON UK plc	1380	1380	1380	1380	1380	1380	1380	Z9	Yes		1500	13	BCA	DEES40
NGET	CCGT	Corby	Corby Power Ltd	401	401	401	401	401	401	401	Z12	Yes			14	BEGA	GREN40_EME
NGET	CCGT	Coryton	Coryton Energy Company Ltd	800	800	800	800	800	800	800	Z15	Yes		880	17	BCA	COSO40
NGET	CCGT	Damhead Creek 1	ScottishPower Generation Ltd	805	805	805	805	805	805	805	Z15	Yes		805	17	BCA	KINO40
NGET	CCGT	Deeside	Deeside Power Ltd	505	505	505	505	505	505	505	Z9	Yes		500	13	BCA	DEES40
NGET	CCGT	Didcot B	RWE Npower plc	1550	1550	1550	1550	1550	1550	1550	Z13	Yes		1500	18	BCA	DIDC40
NGET	CCGT	Drakelow D	E.ON UK plc	0	0	1320	1320	1320	1320	1320	Z11	Yes		1230	14	BCA	DRAK40
NGET	CCGT	Enfield	E.ON UK plc	408	408	408	408	408	408	408	Z14	Yes		408	17	BEGA	BRIM2A_LPN / BRIM2B_LPN / BRIM2C_LPN / BRIM2D_LPN
NGET	CCGT	Grain Stage 2	E.ON UK plc	0	860	860	860	860	860	860	Z15	Yes		860	17	BCA	GRAI40
NGET	CCGT	Grain Stage 3	E.ON UK plc	0	0	430	430	430	430	430	Z15	Yes		430	17	BCA	GRAI40
NGET	CCGT	Great Yarmouth	Great Yarmouth Power Ltd	420	420	420	420	420	420	420	Z12	Yes			14	BEGA	NORW40
NGET	CCGT	Keadby	Keadby Generation Ltd	735	735	735	735	735	735	735	Z8	Yes		794	13	BCA	KEAD40
NGET	CCGT	Killingholme 1	E.ON UK plc	900	900	900	900	900	900	900	Z8	Yes		1000	9	BCA	KILL40
NGET	CCGT	Killingholme 2	Centrica Generation Ltd	665	665	665	665	665	665	665	Z8	Yes		680	9	BCA	KILL40
NGET	CCGT	Kings Lynn A	Centrica KL Ltd	340	340	340	340	340	340	340	Z12	Yes			13	BEGA	WALP40_EME
NGET	CCGT	Langage	Centrica Langage Ltd	905	905	905	905	905	905	905	Z17	Yes		850	20	BCA	LANG40
NGET	CCGT	Little Barford	RWE Npower plc	665	665	665	665	665	665	665	Z12	Yes		750	14	BCA	EASO40
NGET	CCGT	Marchwood	Marchwood Power Ltd	900	900	900	900	900	900	900	Z16	Yes		920	19	BCA	MAWO40
NGET	CCGT	Medway	Medway Power Ltd	700	700	700	700	700	700	700	Z15	Yes		700	17	BCA	GRAI40
NGET	CCGT	Partington Stage 1	Bridestones Developments Ltd	0	0	430	430	430	430	430	Z9	Yes			13	BCA	
NGET	CCGT	Partington Stage 2	Bridestones Developments Ltd	0	0	0	430	430	430	430	Z9	Yes			13	BCA	
NGET	CCGT	Pembroke Stage 1	RWE Npower plc	0	800	800	800	800	800	800	Z13	Yes		840	15	BCA	PEMB40
NGET	CCGT	Pembroke Stage 2	RWE Npower plc	0	1200	1200	1200	1200	1200	1200	Z13	Yes		2060	15	BCA	PEMB40
NGET	CCGT	Peterborough	Centrica PB Ltd	405	405	405	405	405	405	405	Z12	Yes			13	BEGA	WALP40_EME

NGET	CCGT	Rocksavage	Rocksavage Power Company Ltd	810	810	810	810	810	810	810	Z9	Yes		775	13	BCA	ROCK40
NGET	CCGT	Roosecote	Centrica RPS Ltd	229	229	229	229	229	229	229	Z9	Yes			9	BEGA	HUTT40
NGET	CCGT	Rye House	ScottishPower Generation Ltd	715	715	715	715	715	715	715	Z14	Yes		715	17	BCA	RYEH40
NGET	CCGT	Saltend	Saltend Cogeneration Company Ltd	1100	1100	1100	1100	1100	1100	1100	Z8	Yes		1200	9	BCA	SAES20
NGET	CCGT	Seabank 1	Seabank Power Ltd	820	820	820	820	820	820	820	Z13	Yes		1320	15	BCA	SEAB40
NGET	CCGT	Seabank 2	Seabank Power Ltd	414	414	414	414	414	414	414	Z13	Yes			15	BCA	SEAB40
NGET	CCGT	Severn Power Stage 1	Severn Power Ltd	425	425	425	425	425	425	425	Z13	Yes		850	15	BCA	USKM2B
NGET	CCGT	Severn Power Stage 2	Severn Power Ltd	0	425	425	425	425	425	425	Z13	Yes		850	15	BCA	USKM2B
NGET	CCGT	Shoreham	ScottishPower (SCPL) Ltd	420	420	420	420	420	420	420	Z16	Yes			18	BEGA	BOLN40
NGET	CCGT	South Humber Bank 1	Humber Power Ltd	769	769	769	769	769	769	769	Z8	Yes		1312	9	BCA	SHBA40
NGET	CCGT	South Humber Bank 2	Humber Power Ltd	516	516	516	516	516	516	516	Z8	Yes			9	BCA	SHBA40
NGET	CCGT	Spalding	Spalding Energy Company Ltd	880	880	880	880	880	880	880	Z10	Yes		903	13	BCA	SPLN40
NGET	CCGT	Staythorpe C Stage 1	RWE Npower plc	425	425	425	425	425	425	425	Z10	Yes		445	13	BCA	STAY40
NGET	CCGT	Staythorpe C Stage 2	RWE Npower plc	425	425	425	425	425	425	425	Z10	Yes		890	13	BCA	STAY40
NGET	CCGT	Staythorpe C Stage 3	RWE Npower plc	850	850	850	850	850	850	850	Z10	Yes		1780	13	BCA	STAY40
NGET	CCGT	Sutton Bridge A	EDF Energy (Sutton Bridge Power)	800	800	800	800	800	800	800	Z12	Yes		803	13	BCA	WALP40_EME
NGET	CCGT	Sutton Bridge B	West Burton Limited	0	0	0	0	1305	1305	1305	Z12	Yes		1305	13	BCA	WALP40_EME
NGET	CCGT	Teesside	Teesside Power Ltd	1875	1875	1875	1875	1875	1875	1875	Z7	Yes		1875	10	BCA	GRST20
NGET	CCGT	West Burton B Stage 1	West Burton Limited	435	435	435	435	435	435	435	Z10	Yes		1305	13	BCA	WBUR40
NGET	CCGT	West Burton B Stage 2	West Burton Limited	0	435	435	435	435	435	435	Z10	Yes			13	BCA	WBUR40
NGET	CCGT	West Burton B Stage 3	West Burton Limited	0	435	435	435	435	435	435	Z10	Yes			13	BCA	WBUR40
NGET	CCGT	Wilton	Sembcorp Utilities	60	60	60	60	60	60	60	Z7	Yes		176	10	BCA	GRST20
NGET	CHP	Derwent	Derwent Cogeneration Ltd	228	228	228	228	228	228	228	Z11	Yes			14	BEGA	WILE20
NGET	CHP	Fawley CHP	Npower Cogen Trading Ltd	158	158	158	158	158	158	158	Z16	Yes			19	BEGA	FAWL40
NGET	CHP	Immingham Stage 1	Immingham CHP LLP	719	719	719	719	719	719	719	Z8	Yes		760	9	BCA	HUMR40
NGET	CHP	Immingham Stage 2	Immingham CHP LLP	601	601	601	601	601	601	601	Z8	Yes		560	9	BCA	HUMR40
NGET	CHP	Sellafield	Fellside Heat & Power Ltd	155	155	155	155	155	155	155	Z9	Yes			9	BEGA	HUTT40
NGET	CHP	Shotton	Gaz de France Marketing Ltd	210	210	210	210	210	210	210	Z9	Yes			13	BEGA	DEES40
NGET	IGCC with CCS	Blyth	RWE Npower plc	0	0	0	0	0	1600	1600	Z7	Yes		1600	10	BCA	
NGET	IGCC with CCS	Hatfield	Powerfuel plc	0	0	800	800	800	800	800	Z8	Yes		800	13	BCA	
NGET	IGCC with CCS	Teesport	Coastal Energy Ltd	0	0	0	0	0	925	925	Z7	Yes		950	10	BCA	
NGET	Interconnector	East-West Interconnector 1	EirGrid plc	0	0	500	500	500	500	500	Z9	Yes		500	9	BCA	
NGET	Interconnector	East-West Interconnector 2	East West Cable One Ltd	0	0	375	375	375	375	375	Z9	Yes		375	9	BCA	
NGET	Interconnector	French Interconnector	NG Interconnectors Ltd	1988	1988	1988	1988	1988	1988	1988	Z15	Yes		2000	17	BCA	SELL40
NGET	Interconnector	Netherlands Interconnector Stage 1	BritNed Development Ltd	0	0	0	0	0	0	0	Z15	Yes		0	17	BCA	GRAI40
NGET	Interconnector	Netherlands Interconnector Stage 2	BritNed Development Ltd	0	800	800	800	800	800	800	Z15	Yes		800	17	BCA	GRAI40
NGET	Interconnector	Netherlands Interconnector Stage 3	BritNed Development Ltd	0	400	400	400	400	400	400	Z15	Yes		520	17	BCA	GRAI40
NGET	Large Unit Coal	Didcot A	RWE Npower plc	2109	2109	2109	2109	2109	2109	2109	Z13	Yes		2084	18	BCA	DIDC40

NGET	Large Unit Coal + AGT	Aberthaw	RWE Npower plc	1692	1692	1692	1692	1692	1692	1692	Z13	Yes		1557	15	BCA	ABTH20
NGET	Large Unit Coal + AGT	Cottam	EDF Energy (Cottam Power) Ltd	2000	2000	2000	2000	2000	2000	2000	Z10	Yes		2008	13	BCA	COTT40
NGET	Large Unit Coal + AGT	Drax	Drax Power Ltd	3906	3906	3906	3906	3906	3906	3906	Z8	Yes		3945	9	BCA	DRAX40
NGET	Large Unit Coal + AGT	Eggborough	Eggborough Power Ltd	1940	1940	1940	1940	1940	1940	1940	Z8	Yes		2136	9	BCA	EGGB40
NGET	Large Unit Coal + AGT	Ferrybridge	Keadby Generation Ltd	1986	1986	1986	1986	1986	1986	1986	Z8	Yes		1989	9	BCA	FERR20_YED
NGET	Large Unit Coal + AGT	Fiddlers Ferry	Keadby Generation Ltd	1987	1987	1987	1987	1987	1987	1987	Z9	Yes		1995	9	BCA	FIDF20
NGET	Large Unit Coal + AGT	Ironbridge	E.ON UK plc	964	964	964	964	964	964	964	Z11	Yes		1034	14	BCA	IRON40
NGET	Large Unit Coal + AGT	Kingsnorth	E.ON UK plc	1966	1966	1966	1966	1966	1966	1966	Z15	Yes		2088	17	BCA	KINO40
NGET	Large Unit Coal + AGT	Ratcliffe-on-Soar	E.ON UK plc	2021	2021	2021	2021	2021	2021	2021	Z11	Yes		2068	14	BCA	RATS40
NGET	Large Unit Coal + AGT	Rugeley B	Rugeley Power Ltd	1018	1018	1018	1018	1018	1018	1018	Z11	Yes		1026	14	BCA	RUGE40
NGET	Large Unit Coal + AGT	West Burton A	West Burton Ltd	1987	1987	1987	1987	1987	1987	1987	Z10	Yes		2012	13	BCA	WBUR40
NGET	Medium Unit Coal + AGT	Tilbury	RWE Npower plc	1131	1131	1131	1131	1131	1131	1131	Z15	Yes		1468	17	BCA	TILB20
NGET	Nuclear AGR	Dungeness B	British Energy Generation (UK) Ltd	1081	1081	1081	1081	1081	1081	1081	Z15	Yes		1320	17	BCA	DUNG40
NGET	Nuclear AGR	Hartlepool	British Energy Generation (UK) Ltd	1207	1207	1207	1207	1207	1207	1207	Z7	Yes		1332	10	BCA	HATL20
NGET	Nuclear AGR	Heysham 1	British Energy Generation (UK) Ltd	1203	1203	1203	1203	1203	1203	1203	Z9	Yes		2676	9	BCA	HEYS40
NGET	Nuclear AGR	Heysham 2	British Energy Generation (UK) Ltd	1203	1203	1203	1203	1203	1203	1203	Z9	Yes			9	BCA	HEYS40
NGET	Nuclear AGR	Hinkley Point	British Energy Generation (UK) Ltd	1261	1261	1261	1261	1261	1261	1261	Z17	Yes		1400	19	BCA	HINP40
NGET	Nuclear Magnox	Oldbury	Magnox Electric Ltd	470	470	0	0	0	0	0	Z13	Yes		471	15	BCA	OLDS10
NGET	Nuclear Magnox	Wylfa	Magnox Electric Ltd	980	980	0	0	0	0	0	Z9	Yes		1100	11	BCA	WYLF40
NGET	Nuclear PWR	Sizewell B	British Energy Generation (UK) Ltd	1200	1200	1200	1200	1200	1200	1200	Z12	Yes		1320	14	BCA	SIZE40
NGET	OCGT	Cowes	RWE Npower plc	145	145	145	145	145	145	145	Z16	Yes			19	BEGA	FAWL40
NGET	OCGT	Didcot A GTs	RWE Npower plc	100	100	100	100	100	100	100	Z13	Yes			18	BEGA	DIDC40
NGET	OCGT	Indian Queens	AES Indian Queens Power Ltd	140	140	140	140	140	140	140	Z17	Yes		140	20	BCA	INDQ40
NGET	OCGT	Lynes Common	BP (CHP) Ltd	50	50	50	50	50	50	50	Z16	Yes			19	BEGA	N/A
NGET	OCGT	Taylors Lane	E.ON UK plc	144	144	144	144	144	144	144	Z14	Yes		144	16	BCA	WISD20_LPN
NGET	Offshore Wind	Bristol Channel Offshore Windfarm	Channel Energy Ltd	0	0	0	0	0	1512	1512	Z17	Yes		1512	20	BCA	
NGET	Offshore Wind	Docking Shoal Wind Farm Ltd	Centrica (DSW) Ltd	0	0	500	500	500	500	500	Z12	Yes		500	13	BCA	WALP40_EME
NGET	Offshore Wind	Greater Gabbard	Greater Gabbard Offshore Winds Ltd	500	500	500	500	500	500	500	Z12	Yes		500	14	BCA	SIZE40
NGET	Offshore Wind	Gwynt Y Mor Stage 1	Gwynt Y Mor Offshore Wind Farm Ltd	0	0	294	294	294	294	294	Z9	Yes		294	13	BCA	
NGET	Offshore Wind	Gwynt Y Mor Stage 2	Gwynt Y Mor Offshore Wind Farm Ltd	0	0	0	294	294	294	294	Z9	Yes		588	13	BCA	
NGET	Offshore Wind	Gwynt Y Mor Stage 3	Gwynt Y Mor Offshore Wind Farm Ltd	0	0	0	0	147	147	147	Z9	Yes		735	13	BCA	
NGET	Offshore Wind	Heysham Offshore Wind Farm	Heysham Offshore Wind Ltd	0	140	140	140	140	140	140	Z9	Yes		140	9	BCA	HEYS40
NGET	Offshore Wind	Humber Gateway	E.ON UK Renewables Developments Ltd	0	0	300	300	300	300	300	Z8	Yes		300	9	BCA	
NGET	Offshore Wind	Lincs Offshore Wind Farm	Offshore Windpower Ltd	0	250	250	250	250	250	250	Z12	Yes		250	13	BCA	WALP40_EME
NGET	Offshore Wind	London Array Stage 1	E.ON UK plc	0	0	630	630	630	630	630	Z15	Yes		630	17	BCA	CLEV40
NGET	Offshore Wind	London Array Stage 2	E.ON UK plc	0	0	0	0	0	370	370	Z15	Yes		370	17	BCA	CLEV40

NGET	Offshore Wind	Race Bank Wind Farm	Centrica (RBW) Ltd	0	0	0	0	500	500	500	Z12	Yes		500	13	BCA	WALP40_EME
NGET	Offshore Wind	Sheringham Shoal	Scira Offshore Energy Ltd	0	315	315	315	315	315	315	Z12	Yes			14	BEGA	
NGET	Offshore Wind	Thanet	Thanet Offshore Wind Ltd	300	300	300	300	300	300	300	Z15	Yes			17	BEGA	
NGET	Oil + AGT	Fawley	RWE Npower plc	1036	1036	1036	1036	1036	1036	1036	Z16	Yes		1036	19	BCA	FAWL40
NGET	Oil + AGT	Grain	E.ON UK plc	1355	1355	1355	1355	1355	1355	1355	Z15	Yes		2895	17	BCA	GRAI40
NGET	Oil + AGT	Littlebrook	RWE Npower plc	1245	1245	1245	1245	1245	1245	1245	Z14	Yes		1475	17	BCA	LITT40
NGET	Onshore Wind	Carnedd Wen	Npower Renewables Ltd	0	0	0	0	0	0	191	Z9	Yes		201	14	BCA	
NGET	Onshore Wind	Llanbrynmair South	Renewable Energy Systems UK Ltd	0	0	0	0	0	0	110	Z9	Yes		110	14	BCA	
NGET	Onshore Wind	Mid Wales West	SP Manweb	0	0	0	0	0	0	408	Z9	Yes		408	14	BCA	
NGET	Onshore Wind	Pen Y Comoedd	Pen Y Comoedd Wind Farm Ltd	0	0	0	299	299	299	299	Z13	Yes		299	15	BCA	RHIG40
NGET	Pumped Storage	Dinorwig	First Hydro Company	1644	1644	1644	1644	1644	1644	1644	Z9	Yes		1800	12	BCA	DINO40
NGET	Pumped Storage	Ffestiniog	First Hydro Company	360	360	360	360	360	360	360	Z9	Yes		360	13	BCA	FFES20
NGET	Small Unit Coal	Lynemouth	Alcan Aluminium UK Ltd	420	420	420	420	420	420	420	Z7		Yes	420	10	BELLA	BLYT20
NGET	Small Unit Coal	Uskmouth	Uskmouth Power Company	363	363	363	363	363	363	363	Z13	Yes		363	15	BCA	USKM2A / USKM2C / USKM2D
NGET	Woodchip	Port Talbot	Prenergy Power Ltd	0	0	350	350	350	350	350	Z13	Yes		350	15	BCA	MAGA20
SHETL	CCGT	Peterhead	SSE Generation Ltd	1524	1524	1524	1524	1524	1524	1524	Z2	Yes		1524	2	BCA	PEHE20
SHETL	CHP	Stoneywood Mills (Wiggins Teape Stoneywood)	Arjo Wiggins Fine Papers Ltd	12	12	12	12	12	12	12	Z2		Yes		1	BELLA	DYCE1Q / DYCE1R
SHETL	Hydro	Aigas	SSE Generation Ltd	20	20	20	20	20	20	20	Z1	Yes		20	1	BCA	AIGA1Q
SHETL	Hydro	Cashlie	SSE Generation Ltd	11	11	11	11	11	11	11	Z3	Yes			4	BEGA	KIIN10
SHETL	Hydro	Cassley	SSE Generation Ltd	10	10	10	10	10	10	10	Z1		Yes		1	BELLA	CASS1Q
SHETL	Hydro	Ceannacroc	SSE Generation Ltd	20	20	20	20	20	20	20	Z1	Yes			3	BEGA	CEAN1Q
SHETL	Hydro	Clachan	SSE Generation Ltd	40	40	40	40	40	40	40	Z4		Yes		5	BELLA	CLAC1Q
SHETL	Hydro	Clunie	SSE Generation Ltd	61	61	61	61	61	61	61	Z3	Yes		61	4	BCA	CLUN1S / CLUN1T
SHETL	Hydro	Culligran	SSE Generation Ltd	19	19	19	19	19	19	19	Z1	Yes		19	1	BCA	CULL1Q
SHETL	Hydro	Deanie	SSE Generation Ltd	38	38	38	38	38	38	38	Z1	Yes		38	1	BCA	DEAN1Q
SHETL	Hydro	Errochty	SSE Generation Ltd	75	75	75	75	75	75	75	Z3	Yes		75	4	BCA	ERRO10
SHETL	Hydro	Fasnakyle Compensation Hydro (Unit 4)	SSE Generation Ltd	0	0	0	0	0	8	8	Z1	Yes			3	BEGA	FASN10
SHETL	Hydro	Fasnakyle G1 & G3	SSE Generation Ltd	46	46	46	46	46	46	46	Z1	Yes		46	3	BCA	FASN10
SHETL	Hydro	Fasnakyle G2	SSE Generation Ltd	23	23	23	23	23	23	23	Z1	Yes			3	BEGA	FASN10
SHETL	Hydro	Finlarig	SSE Generation Ltd	16	16	16	16	16	16	16	Z3	Yes		17	4	BCA	FINL1Q
SHETL	Hydro	Glendoe, Fort Augustus Stage 1	SSE Generation Ltd	52	52	52	52	52	52	52	Z1	Yes		100	3	BCA	GLDO10
SHETL	Hydro	Glendoe, Fort Augustus Stage 2	SSE Generation Ltd	0	0	0	0	48	48	48	Z1	Yes			3	BCA	GLDO10
SHETL	Hydro	Glenmorrison	SSE Generation Ltd	37	37	37	37	37	37	37	Z1	Yes		37	3	BCA	GLEN1Q
SHETL	Hydro	Grudie Bridge	SSE Generation Ltd	22	22	22	22	22	22	22	Z1		Yes		1	BELLA	GRUB1Q / GRUB1R
SHETL	Hydro	Inverawe	SSE Generation Ltd	25	25	25	25	25	25	25	Z4		Yes		5	BELLA	TAYN1Q / TAYN1R
SHETL	Hydro	Invergarry	SSE Generation Ltd	20	20	20	20	20	20	20	Z1	Yes		20	3	BCA	INGA1Q
SHETL	Hydro	Kilmorack	SSE Generation Ltd	20	20	20	20	20	20	20	Z1	Yes		20	1	BCA	KIOR1Q
SHETL	Hydro	Kinlochleven	Alcan Aluminium UK Ltd	20	20	20	20	20	20	20	Z1		Yes		3	BELLA	KILO10

SHETL	Hydro	Livishie	SSE Generation Ltd	15	15	15	15	15	15	15	Z1	Yes		15	3	BEGA	GLEN1Q
SHETL	Hydro	Lochay	SSE Generation Ltd	47	47	47	47	47	47	47	Z3	Yes		47	4	BCA	LOCH10
SHETL	Hydro	Luichart	SSE Generation Ltd	34	34	34	34	34	34	34	Z1	Yes		34	1	BCA	LUIC1Q / LUIC1R
SHETL	Hydro	Mossford	SSE Generation Ltd	19	19	19	19	19	19	19	Z1	Yes		19	1	BCA	MOSS1Q / MOSS1R
SHETL	Hydro	Nant	SSE Generation Ltd	15	15	15	15	15	15	15	Z4	Yes		15	5	BCA	LOCN1Q
SHETL	Hydro	Orrin	SSE Generation Ltd	18	18	18	18	18	18	18	Z2	Yes		18	1	BCA	ORRI1Q
SHETL	Hydro	Pitlochry	SSE Generation Ltd	15	15	15	15	15	15	15	Z3	Yes		15	4	BEGA	CLUN1S / CLUN1T
SHETL	Hydro	Quoich	SSE Generation Ltd	18	18	18	18	18	18	18	Z1	Yes		22	3	BCA	QUOI10
SHETL	Hydro	Rannoch	SSE Generation Ltd	44	44	44	44	44	44	44	Z3		Yes		4	BELLA	RANN1Q / RANN1R
SHETL	Hydro	Shin	SSE Generation Ltd	19	19	19	19	19	19	19	Z1		Yes		1	BELLA	SHIN10
SHETL	Hydro	Sloy G1 & G4	SSE Generation Ltd	72	72	72	72	72	72	72	Z4	Yes			5	BEGA	SLOY10
SHETL	Hydro	Sloy G2 & G3	SSE Generation Ltd	80	80	80	80	80	80	80	Z4	Yes		80	5	BCA	SLOY10
SHETL	Hydro	St Fillans	SSE Generation Ltd	17	17	17	17	17	17	17	Z3		Yes		4	BELLA	SFIL1Q
SHETL	Hydro	Torr Achilty	SSE Generation Ltd	15	15	15	15	15	15	15	Z1	Yes			1	BEGA	BEAU10
SHETL	Hydro	Tummel	SSE Generation Ltd	34	34	34	34	34	34	34	Z3		Yes		4	BELLA	TUMB1Q / TUMB1R
SHETL	OCGT	Flotta Terminal	Talisman Energy (UK) Ltd	10	10	10	10	10	10	10	Z1		Yes		1	BELLA	THSO1Q / THSO1R
SHETL	Onshore Wind	An Suidhe	An Suidhe Wind Farm Ltd	30	30	30	30	30	30	30	Z4	Yes		30	5	BCA	ERED10
SHETL	Onshore Wind	Ardkinglas, Clachan (SRO)	AMEC Project Investments Ltd	19	19	19	19	19	19	19	Z4		Yes		5	BELLA	CLAC10
SHETL	Onshore Wind	Aultmore Windfarm	AMEC Wind Energy Ltd	0	0	0	0	0	60	60	Z1	Yes		60	1	BCA	AULW1Q / AULW1S
SHETL	Onshore Wind	Baillie & Bardnaheigh Wind	Baillie Windfarm Ltd	0	0	0	0	0	57	57	Z1	Yes			1	BEGA	BABW1Q
SHETL	Onshore Wind	Beinn an Turic 2	CRE Energy Ltd	0	38	38	38	38	38	38	Z4	Yes			5	BEGA	
SHETL	Onshore Wind	Beinn an Turic Wind (SRO)	CRE Energy Ltd	30	30	30	30	30	30	30	Z4		Yes		5	BELLA	CAAD1Q
SHETL	Onshore Wind	Beinn Tharsuinn	CRE Energy Ltd	29	29	29	29	29	29	29	Z1	Yes			1	BEGA	ALNE1Q / ALNE1R
SHETL	Onshore Wind	Ben Aketil Wind	Ben Aketil Wind Farm Ltd	21	21	21	21	21	21	21	Z1		Yes		3	BELLA	DUGR1Q
SHETL	Onshore Wind	Ben Aketil Wind (Add. Cap.)	Ben Aketil Wind Farm Ltd	7	7	7	7	7	7	7	Z1		Yes		3	BELLA	DUGR1Q
SHETL	Onshore Wind	Berry Burn Windfarm	Catamount Energy Ltd	0	0	0	0	82	82	82	Z1		Yes		1	BELLA	CAKW2Q
SHETL	Onshore Wind	Black Craig 40MW Windfarm, Dunoon	Argyll Wind Farms	0	0	0	0	40	40	40	Z3		Yes		5	BELLA	DUNO1Q / DUNO1R
SHETL	Onshore Wind	Black Craig 90MW, Dunoon	Infinergy Ltd	0	0	0	0	0	90	90	Z4	Yes		90	5	BCA	
SHETL	Onshore Wind	Boulfrich Wind, Dunbeath	Boulfrich Wind Farm Ltd	14	14	14	14	14	14	14	Z1		Yes		1	BELLA	DUBE1Q
SHETL	Onshore Wind	Boyndie Wind	Boyndie Wind Energy Ltd	14	14	14	14	14	14	14	Z2		Yes		1	BELLA	KEIT10 / MACD1Q
SHETL	Onshore Wind	Boyndie Wind (Add. Cap.)	Boyndie Wind Energy Ltd	7	7	7	7	7	7	7	Z2		Yes		1	BELLA	KEIT10 / MACD1Q
SHETL	Onshore Wind	Braes of Doune	Airtricity Developments (Scotland) Ltd	74	74	74	74	74	74	74	Z4	Yes			6	BEGA	BRAC1Q / BRAC1R
SHETL	Onshore Wind	Cairn Uish Wind, Rothes	Rothes Wind Ltd	51	51	51	51	51	51	51	Z1		Yes		1	BELLA	DAAS20
SHETL	Onshore Wind	Calliachar Wind Farm, Aberfeldy	I & H Brown Ltd	0	0	0	0	0	62	62	Z3	Yes		96	4	BCA	CALW20
SHETL	Onshore Wind	Camster	Powergen Renewables Ltd	0	0	0	0	0	62	62	Z1		Yes		1	BELLA	MYBS1Q / MYBS1R
SHETL	Onshore Wind	Careston Wind Farm, Brechin, Angus	Renewable Energy Systems UK Ltd	0	0	0	0	0	0	32	Z2	Yes		32	4	BCA	
SHETL	Onshore Wind	Carraig Gheal (Fernoch)	Greenpower (Carraig Gheal) Ltd	0	60	60	60	60	60	60	Z4	Yes		60	5	BCA	FERO10
SHETL	Onshore Wind	Causeymire	Causeymire Windfarm Ltd	48	48	48	48	48	48	48	Z1		Yes		1	BELLA	MYBS1Q / MYBS1R
SHETL	Onshore Wind	Causeymire Phase 2	Causeymire Windfarm Ltd	0	0	7	7	7	7	7	Z1		Yes		1	BELLA	MYBS1Q / MYBS1R

SHETL	Onshore Wind	Clashindarroch Wind, Huntly	AMEC Wind Energy Ltd	0	0	0	0	0	113	113	Z2	Yes			1	BEGA	CLAS20
SHETL	Onshore Wind	Cruach Mhor	CRE Energy Ltd	30	30	30	30	30	30	30	Z3		Yes		5	BELLA	DUNO1Q / DUNO1R
SHETL	Onshore Wind	Deucheran Hill	E.ON UK Renewables Ltd	15	15	15	15	15	15	15	Z4		Yes		5	BELLA	CAAD1Q / CAAD1R
SHETL	Onshore Wind	Drumderg Wind Farm, Dalrulzion	SSE Generation Ltd	32	32	32	32	32	32	32	Z3		Yes		4	BELLA	COUA10
SHETL	Onshore Wind	Dummuies Windfarm, Insch	Eco 2 Ltd	10	10	10	10	10	10	10	Z2		Yes		1	BELLA	KINT10
SHETL	Onshore Wind	Dunbeath Wind Farm	Dunbeath Wind Energy Ltd	0	0	0	0	0	55	55	Z1		Yes		1	BELLA	DUBE1Q
SHETL	Onshore Wind	Edinbane Wind, Skye	AMEC Wind Energy Ltd	42	42	42	42	42	42	42	Z1	Yes		56	3	BCA	EDIN10
SHETL	Onshore Wind	Eishken Estate, Isle of Lewis	Beinn Mhor Power Ltd	0	0	0	0	0	300	300	Z1	Yes		300	3	BCA	ULLA20
SHETL	Onshore Wind	Fairburn Wind Farm	SSE Generation Ltd	40	40	40	40	40	40	40	Z1		Yes		1	BELLA	ORRI1Q / ORRI1R
SHETL	Onshore Wind	Farr Wind Farm, Tomatin	Farr Wind Farm Ltd	92	92	92	92	92	92	92	Z1	Yes		92	1	BCA	FAAR1Q / FAAR1R
SHETL	Onshore Wind	Glens of Foudland Wind (SRO)	Glens of Foudland Wind Farm Ltd	26	26	26	26	26	26	26	Z2	Yes			1	BEGA	KEIT10 / KINT10
SHETL	Onshore Wind	Gordonbush Wind	SSE Generation Ltd	70	70	70	70	70	70	70	Z1	Yes		88	1	BCA	GORW20
SHETL	Onshore Wind	Griffin Windfarm	GreenPower (Griffin) Ltd	0	204	204	204	204	204	204	Z3	Yes		216	4	BCA	GRIF1S / GRIF1T
SHETL	Onshore Wind	Kilbraur (Strath Brora) Wind Farm Stage 1	Kilbraur Wind Energy Ltd	48	48	48	48	48	48	48	Z1	Yes		48	1	BCA	STRB20
SHETL	Onshore Wind	Kilbraur (Strath Brora) Wind Farm Stage 2	Kilbraur Wind Energy Ltd	20	20	20	20	20	20	20	Z1	Yes		20	1	BCA	STRB20
SHETL	Onshore Wind	Lairg - Achany Wind Farm	SSE Generation Ltd	50	50	50	50	50	50	50	Z1		Yes		1	BELLA	LAIR1Q
SHETL	Onshore Wind	Mid Hill Wind, Stonehaven	Mid Hill Wind Ltd	0	0	0	0	75	75	75	Z2		Yes		1	BELLA	MIHW2Q
SHETL	Onshore Wind	Millenium Wind, Ceannacroc Stage 1	Millenium Wind Energy Ltd	40	40	40	40	40	40	40	Z1	Yes		40	3	BCA	MILW1S
SHETL	Onshore Wind	Millenium Wind, Ceannacroc Stage 2	Millenium Wind Energy Ltd	10	10	10	10	10	10	10	Z1	Yes		10	3	BCA	MILW1S
SHETL	Onshore Wind	Millenium Wind, Ceannacroc Stage 3	Millenium Wind Energy Ltd	15	15	15	15	15	15	15	Z1	Yes		15	3	BCA	MILW1S
SHETL	Onshore Wind	Montreathmont Moor Wind, Angus	Scottish Hydro-Electric Power Distribution Ltd	0	0	0	0	0	40	40	Z2		Yes		1	BELLA	BRID1Q
SHETL	Onshore Wind	North Nesting Wind, Shetland	SSE Generation Ltd	0	0	0	0	0	250	250	Z1	Yes		250	1	BCA	NNEW20
SHETL	Onshore Wind	Novar	Beaufort Wind Ltd	18	18	18	18	18	18	18	Z1		Yes		1	BELLA	ALNE1Q / ALNE1R
SHETL	Onshore Wind	Novar 2 Wind Farm, Alness	Novar 2 Wind Farm Ltd	0	0	0	0	0	32	32	Z2		Yes	32	1	BELLA	ALNE1Q / ALNE1R
SHETL	Onshore Wind	Pairc (South Lochs) Wind, Lewis	SSE Generation Ltd	0	0	0	0	94	94	94	Z1	Yes		250	3	BCA	ULLA20
SHETL	Onshore Wind	Paul's Hill Wind	Paul's Hill Wind Ltd	70	70	70	70	70	70	70	Z1		Yes		1	BELLA	GLFA10
SHETL	Onshore Wind	Shira	Shira Wind Limited	0	0	0	0	52	52	52	Z4	Yes		75	5	BCA	SHRA10
SHETL	Onshore Wind	Stacain Wind Farm, Sron Mor, Inveraray	Wind Prospect Ltd	0	0	0	0	42	42	42	Z4	Yes		28	5	BCA	SROM10
SHETL	Onshore Wind	Strathy North & South Wind	SSE Generation Ltd	0	0	0	0	226	226	226	Z1	Yes		226	1	BCA	STRW20
SHETL	Onshore Wind	Stroupster Wind Farm, near Wick, Caithness	Stroupster Wind Farm Ltd	0	0	0	0	0	32	32	Z1		Yes	32	1	BELLA	THSO1Q / THSO1R
SHETL	Onshore Wind	Tangy (1) Wind, Argyll	SSE Generation Ltd	13	13	13	13	13	13	13	Z4		Yes		5	BELLA	CAAD1Q / CAAD1R
SHETL	Onshore Wind	Tangy (Add. Cap.)	SSE Generation Ltd	6	6	6	6	6	6	6	Z4		Yes		5	BELLA	CAAD1Q / CAAD1R
SHETL	Onshore Wind	Tomatin Windfarm	Eurus Energy UK Ltd	0	0	0	0	30	30	30	Z1		Yes		1	BELLA	BOAG1Q
SHETL	Onshore Wind	Tullo Wind Farm, Laurencekirk	Tullo Wind Farm Ltd	14	14	14	14	14	14	14	Z2		Yes		4	BELLA	BREC10
SHETL	Pumped Storage	Foyers	SSE Generation Ltd	300	300	300	300	300	300	300	Z1	Yes		300	1	BCA	FOYE20

SPT	Biomass	Rothes Biopower Plant	Npower Cogen Ltd	0	52	52	52	52	52	52	Z5	Yes			6	BEGA	BLHI20
SPT	Biomass	Stevens Croft	E.ON UK plc	45	45	45	45	45	45	45	Z6		Yes		7	BELLA	CHAP10
SPT	CHP	BP Grangemouth	Grangemouth CHP Ltd	120	120	120	120	120	120	120	Z6	Yes			6	BEGA	GRMO20
SPT	CHP	Fife Energy Stage 1	SSE Generation Ltd	63	63	63	63	63	63	63	Z5	Yes		135	6	BCA	FIFE10
SPT	CHP	Fife Energy Stage 2	SSE Generation Ltd	60	60	60	60	60	60	60	Z5	Yes			6	BCA	FIFE10
SPT	Hydro	Tongland	ScottishPower Generation Ltd	33	33	33	33	33	33	33	Z6		Yes		7	BELLA	TONG10
SPT	Interconnector	Moyle Interconnector (Import)	Moyle Interconnector Ltd	80	80	80	80	80	80	80	Z6	Yes		80	8	BCA	AUCH20
SPT	Large Unit Coal	Longannet	ScottishPower Generation Ltd	2304	2304	2304	2304	2304	2304	2304	Z5	Yes		2304	6	BCA	LOAN20
SPT	Medium Unit Coal	Cockenzie	ScottishPower Generation Ltd	1102	1102	1102	1102	1102	1102	1102	Z6	Yes		1152	7	BCA	COCK20
SPT	Nuclear AGR	Hunterston	British Energy Generation (UK) Ltd	1089	1089	1089	1089	1089	1089	1089	Z6	Yes		1320	7	BCA	HUER40
SPT	Nuclear AGR	Torness	British Energy Generation (UK) Ltd	1200	1200	1200	1200	1200	1200	1200	Z6	Yes		1370	7	BCA	TORN40
SPT	Onshore Wind	Afton	E.ON UK Renewables Developments Ltd	0	0	0	77	77	77	77	Z6	Yes		77	7	BCA	AFTN10
SPT	Onshore Wind	Aikengall	Community Windpower Ltd	48	48	48	48	48	48	48	Z6		Yes		7	BELLA	AIKN10
SPT	Onshore Wind	Andershaw	Catamount Energy Limited	0	45	45	45	45	45	45	Z6	Yes		45	7	BCA	ANDS10
SPT	Onshore Wind	Arecleoch	CRE Energy Ltd	0	150	150	150	150	150	150	Z6	Yes		150	7	BCA	AREC10
SPT	Onshore Wind	Auchencorth	E.ON UK Renewables Developments Ltd	0	45	45	45	45	45	45	Z6	Yes		45	7	BCA	KAIM20
SPT	Onshore Wind	Ballindalloch Muir Wind Farm, Balfron	Ballindalloch Muir Wind Farm	0	0	21	21	21	21	21	Z3		Yes		5	BELLA	BAMW10
SPT	Onshore Wind	Barmoor	Catamount Energy Limited	0	30	30	30	30	30	30	Z6		Yes		7	BELLA	BERW1Q / BERW1R
SPT	Onshore Wind	Black Law	CRE Energy Ltd	134	134	134	134	134	134	134	Z6	Yes		134	7	BCA	BLLA10
SPT	Onshore Wind	Blackcraig	SSE Generation Ltd	0	0	0	0	71	71	71	Z5	Yes		71	5	BCA	BLCK10
SPT	Onshore Wind	Brockloch Rig	Brockloch Rig Windfarm Ltd	0	0	0	60	60	60	60	Z6	Yes		60	7	BCA	WIST10
SPT	Onshore Wind	Carscreugh, Dumfries & Galloway	Gamesa Energy UK Ltd	0	0	0	0	21	21	21	Z6	Yes		21	7	BCA	CCDG10
SPT	Onshore Wind	Clyde	Airtricity Developments (Scotland) Ltd	0	519	519	519	519	519	519	Z6	Yes		577	7	BCA	CLYDE20
SPT	Onshore Wind	Crystal Rig 1	Crystal Rig Windfarm Ltd	62	62	62	62	62	62	62	Z6		Yes		7	BELLA	DUNB1Q / DUNB1R
SPT	Onshore Wind	Crystal Rig 2	Fred Olsen Renewables Ltd	200	200	200	200	200	200	200	Z6	Yes		200	7	BCA	DUNB1Q / DUNB1R
SPT	Onshore Wind	Dalswinton	Airtricity Developments (Scotland) Ltd	30	30	30	30	30	30	30	Z6		Yes		7	BEGA	DUMF10
SPT	Onshore Wind	Dersalloch	CRE Energy Ltd	0	0	69	69	69	69	69	Z6	Yes		75	7	BCA	DERS10
SPT	Onshore Wind	Drone Hill	PM Renewables Ltd	0	38	38	38	38	38	38	Z6		Yes		7	BELLA	BERW1Q / BERW1R
SPT	Onshore Wind	Dun Law extension	CRE Energy Ltd	30	30	30	30	30	30	30	Z6	Yes		30	7	BCA	DUNE10
SPT	Onshore Wind	Earlsburn	Earlsburn Wind Energy Ltd	35	35	35	35	35	35	35	Z5		Yes		6	BELLA	STIR1Q / STIR1R
SPT	Onshore Wind	Earlshaugh	Wind Energy (Earlshaugh) Limited	0	0	108	108	108	108	108	Z6	Yes		108	7	BCA	MOFF40
SPT	Onshore Wind	Ewe Hill	CRE Energy Ltd	0	0	66	66	66	66	66	Z6	Yes		92	7	BCA	EWEH10
SPT	Onshore Wind	Fallago	FLR 2003 Ltd	0	0	144	144	144	144	144	Z6	Yes		180	7	BCA	FALL40
SPT	Onshore Wind	Hadyard Hill	SSE Generation Ltd	117	117	117	117	117	117	117	Z6	Yes		144	7	BCA	MAYB10
SPT	Onshore Wind	Harestanes	CRE Energy Ltd	0	0	140	140	140	140	140	Z6	Yes		282	7	BCA	HARE10
SPT	Onshore Wind	Harrows Law	SSE Generation Ltd	0	0	55	55	55	55	55	Z6	Yes		247	7	BCA	HALA10
SPT	Onshore Wind	HearthStanes B Windfarm	Wind Energy (Hearthstanes) Limited	0	0	0	81	81	81	81	Z6	Yes		81	7	BCA	MOFF40

SPT	Onshore Wind	Kingsburn Wind farm, Fintry, Stirling	Scottish Hydro-Electric Power Distribution Ltd	0	20	20	20	20	20	20	Z4		Yes		6	BELLA	KIBU10
SPT	Onshore Wind	Kyle	AMEC Wind Energy Ltd	0	0	300	300	300	300	300	Z6	Yes		300	7	BCA	KYLS10
SPT	Onshore Wind	Longpark	Wind Prospect Ltd	38	38	38	38	38	38	38	Z6	Yes		48	7	BCA	LONP10
SPT	Onshore Wind	Margree	NBW Wind Energy Ltd	0	0	0	0	70	70	70	Z6	Yes		70	7	BCA	MARG10
SPT	Onshore Wind	Mark's Hill	Catamount Energy Ltd	0	99	99	99	99	99	99	Z6	Yes		99	7	BCA	MAHI20
SPT	Onshore Wind	Minsca	Minsca Wind Farm (Scotland) Ltd	38	38	38	38	38	38	38	Z6		Yes		7	BELLA	CHAP10
SPT	Onshore Wind	Neilston	Gamesa Energy UK Ltd	0	0	0	100	100	100	100	Z6	Yes		100	7	BCA	NELS10
SPT	Onshore Wind	Newfield	Wind Energy (Newfield) Limited	0	0	60	60	60	60	60	Z6	Yes		60	7	BCA	NEWF10
SPT	Onshore Wind	Pencloe	NBW Wind Energy Ltd	0	0	0	63	63	63	63	Z6	Yes		63	7	BCA	PENC10
SPT	Onshore Wind	Toddleburn	I & H Brown Toddleburn Ltd	36	36	36	36	36	36	36	Z6	Yes		36	7	BCA	TODD10
SPT	Onshore Wind	Tormywheel	PM Renewables Ltd	0	32	32	32	32	32	32	Z6		Yes		7	BELLA	BAGA1Q / BAGA1R
SPT	Onshore Wind	Ulzieside	NBW Wind Energy Ltd	0	0	0	69	69	69	69	Z6	Yes		69	7	BCA	ULZI10
SPT	Onshore Wind	Waterhead Moor	SSE Generation Ltd	0	0	72	72	72	72	72	Z6	Yes		155	5	BCA	WAMR10
SPT	Onshore Wind	Whitelee Stage 1	CRE Energy Ltd	76	76	76	76	76	76	76	Z6	Yes		322	7	BCA	WHIL20
SPT	Onshore Wind	Whitelee Stage 2	CRE Energy Ltd	218	218	218	218	218	218	218	Z6	Yes			7	BCA	WHIL20
SPT	Onshore Wind	Whitelee Stage 3	CRE Energy Ltd	29	29	29	29	29	29	29	Z6	Yes			7	BCA	WHIL20
SPT	Onshore Wind	Whiteside Hill	Airtricity Developments (Scotland) Ltd	0	0	0	27	27	27	27	Z6	Yes		27	7	BCA	WTSH10
SPT	Pumped Storage	Cruachan	ScottishPower Generation Ltd	440	440	440	440	440	440	440	Z3	Yes		440	5	BCA	CRUA2Q / CRUA2R

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Table 3.6 - Generating Unit Data

Station Name	Set No	BM Unit	Plant Type	Unit Effective Capacity (MW)	Commissioning Year	MVAr Lead	MVAr Lag	MVA Infeed	Node	SYS Study Zone	Licensee
Aberthaw B	7	T_ABTH7	Large Coal	547	1976	-163	193.9	1547	ABTH20	Z13	NGET
Aberthaw B	8	T_ABTH8	Large Coal	547	1971	-163.6	193.2	1561.9	ABTH20	Z13	NGET
Aberthaw B	9	T_ABTH9	Large Coal	547	1979	-162.8	194.1	1599.5	ABTH20	Z13	NGET
Aberthaw B		T_ABTH7G	OCGT	17	1967				ABTH20	Z13	NGET
Aberthaw B		T_ABTH8G	OCGT	17	1967				ABTH20	Z13	NGET
Aberthaw B		T_ABTH9G	OCGT	17	1967				ABTH20	Z13	NGET
Aigas	1		Hydro	20		-1.1	-1.1	110	AIGA1Q	Z1	SHETL
Aikengall			Wind	48	2009	-15.8	15.8	252	AIKE30	Z6	SPT
Ardkinglas	1		Wind	19	2008	-3.5	3.5	129	ARDK80	Z1	SHETL
Baglan Bay		T_BAGE-1	CCGT	520	2002	-295	173.7	1583.7	BAGB20	Z13	NGET
Baglan Bay		T_BAGE-2	CCGT	32.3	2002	-14.6	11.3	109	BAGB20	Z13	NGET
Barking		T_BARK-1	CCGT	127.5	1994	-65.9	52.4	485.9	BARP21	Z14	NGET
Barking		T_BARK-1	CCGT	127.5	1994	-66	52.4	485.5	BARP21	Z14	NGET
Barking		T_BARK-1	CCGT	139.5	1994	-69.5	50.1	499.3	BARP21	Z14	NGET
Barking		T_BARKB2	CCGT	127.5	1994	-66.8	55.2	489.1	BARP22	Z14	NGET
Barking		T_BARKB2	CCGT	127.5	1994	-65.9	52.4	485.8	BARP22	Z14	NGET
Barking		T_BARKB2	CCGT	127.5	1994	-66	52.3	485	BARP22	Z14	NGET
Barking		T_BARKB2	CCGT	223	1994	-115.9	70.1	594.7	BARP22	Z14	NGET
Barmoor			Wind	30	2008	-9.9	9.9	141	BARM30	Z6	SPT
Barry	1		CCGT	245	1998	-74.1	45.2	645.8	AESB11	Z13	NGET
Barry	2		CCGT	75	1998	-31.6	23.6	324.4	AESB11	Z13	NGET
Beinn an Tuirc	1		Wind	30	2001	-6	-6	153	BTUI8W	Z3	SHETL
Beinn Tharsuinn	1		Wind	29	2004	-5	5	152	BETH80	Z1	SHETL
Ben Aketil	1		Wind	28	2007	-6.9	6.9	143	BENA80	Z1	SHETL
Black Law	1		Wind	67	2005	-31.5	21.8	244	BLLA11	Z6	SPT
Black Law	2		Wind	67	2005	-31.5	21.9	244.2	BLLA11	Z6	SPT
Boyndie	1		Wind	21	2005	-7	7	104	BOYN8W	Z2	SHETL
Braes of Doune Wind	1		Wind	37	2004	-7.3	10.7	258	BRDU81	Z4	SHETL
Braes of Doune Wind	2		Wind	37	2004	-7.3	10.7	258	BRDU82	Z4	SHETL
Brigg	1		CCGT	42.7	1993	-16.3	22.2	221.4	BRIG10	Z8	NGET
Brigg	2		CCGT	42.7	1993	-16.3	22.2	221.4	BRIG11	Z8	NGET
Brigg	3		CCGT	43.7	1993	-16.4	22.1	221.4	BRIG12	Z8	NGET
Brigg	4		CCGT	43.7	1993	-16.4	22.1	221.4	BRIG13	Z8	NGET
Brigg	5		CCGT	43.7	1993	-16.4	22.1	221.4	BRIG14	Z8	NGET

Brigg	6		CCGT	43.7	1993	-16.4	22.1	221.4	BRIG15	Z8	NGET
Brimsdown	1	T_EECL-1	CCGT	408	1999	-212.5	180.4	1080.5	BRIM10	Z14	NGET
Cairn Uish Rothes	1		Wind	51	2004	-16	16	261	CAIR8W	Z1	SHETL
Cashlie	1		Hydro	11		-1	-1	34	CASH30	Z4	SHETL
Cassley			Hydro	10						Z1	SHETL
Causeymire	1		Wind	27	2004	-2.5	-2.5	141	CAUS81	Z1	SHETL
Causeymire	2		Wind	27	2004	-2.5	-2.5	141	CAUS82	Z1	SHETL
Ceannacroc	1		Hydro	10		-0.9	-0.9	65	CEAN1Q	Z1	SHETL
Ceannacroc	2		Hydro	10		0	0	24	CEAN80	Z1	SHETL
Clachan	1		Hydro	40		-4	-4	147	CLAC1Q	Z4	SHETL
Clunie	1	CAS-CLU01	Hydro	20.3		-0.8	-0.8	80	CLUN1Q	Z4	SHETL
Clunie	2		Hydro	20.3		0	0	94	CLUN82	Z4	SHETL
Clunie	3		Hydro	20.3		0	0	94	CLUN82	Z4	SHETL
Cockenzie	1	COCK-1	Large Coal	276		-108	117	941	COCK20	Z6	SPT
Cockenzie	2	COCK-2	Large Coal	276		-108	117	941	COCK20	Z6	SPT
Cockenzie	3	COCK-3	Large Coal	276		-56	-56	941	COCK20	Z6	SPT
Cockenzie	4	COCK-4	Large Coal	276		-56	-56	941	COCK20	Z6	SPT
Connahs Quay		T_CNQPS-1	CCGT	345	1996	-174.4	157.2	1061.6	DEES41	Z9	NGET
Connahs Quay		T_CNQPS-2	CCGT	345	1996	-174.5	157.1	1061	DEES41	Z9	NGET
Connahs Quay		T_CNQPS-3	CCGT	345	1996	-174.7	156.8	1059.2	DEES41	Z9	NGET
Connahs Quay		T_CNQPS-4	CCGT	345	1996	-174.6	157.8	1060	DEES41	Z9	NGET
Corby			CCGT	133.7	1993	-84.9	55.9	457.2	GREN11	Z12	NGET
Corby			CCGT	133.7	1993	-84.9	55.9	457.2	GREN12	Z12	NGET
Corby			CCGT	133.7	1993	-84.9	55.9	457.2	GREN12	Z12	NGET
Coryton		T_COSO-1	CCGT	266.7	2000	-135.4	130.9	1062.3	COSO40	Z15	NGET
Coryton		T_COSO-1	CCGT	266.7	2000	-135.4	130.9	1062.3	COSO40	Z15	NGET
Coryton		T_COSO-1	CCGT	266.7	2000	-122.4	155.6	1029.5	COSO40	Z15	NGET
Cottam	1	T_COTPS-1	Large Coal	495	1969	-193.4	174.1	1522	COTT40	Z10	NGET
Cottam	2	T_COTPS-2	Large Coal	505	1969	-190.2	154.9	1527.4	COTT40	Z10	NGET
Cottam	3	T_COTPS-3	Large Coal	505	1970	-195.1	155.4	1531.4	COTT40	Z10	NGET
Cottam	4	T_COTPS-4	Large Coal	495	1970	-192.1	175.7	1533.3	COTT40	Z10	NGET
Cottam Dev Centre		T_CDCL_01	CCGT	395	2000	-183.9	164.8	2043.8	COTT40	Z10	NGET
Cowes	1		OCGT	73	1982	-33.2	30.5	299	FAWL10	Z16	NGET
Cowes	2		OCGT	73	1982	-33.1	30.6	301	FAWL10	Z16	NGET
Cruach Mhor Glendaruel	1		Wind	30	2004	-2.5	-2.5	148	CRMH8W	Z1	SHETL
Cruachan	1	CRUA-1	Pumped Storage	110		-59.3	37.1	441	CRUA2Q	Z4	SPT

Cruachan	2	CRUA-2	Pumped Storage	110		-59.2	37.2	442	CRUA2Q	Z4	SPT
Cruachan	3	CRUA-3	Pumped Storage	110		-59	37.4	507	CRUA2R	Z4	SPT
Cruachan	4	CRUA-4	Pumped Storage	110		-59	37.4	477	CRUA2R	Z4	SPT
Crystal Rig 2			Wind	200	2009	-65.7	65.7	611	CRYR30	Z6	SPT
Crystal Rigg Duns	1		Wind	63	2003	-24.6	25.8	285.7	CRYR30	Z6	SPT
Culligran	1		Hydro	19		-1.1	6.9	70	CULL1Q	Z1	SHETL
Dalswinton			Wind	30						Z6	SPT
Damhead Creek		T_DAMC-1	CCGT	273	2000	-129.3	121.5	889.9	DAMC40	Z15	NGET
Damhead Creek		T_DAMC-1	CCGT	273	2000	-130.4	112	901.5	DAMC40	Z15	NGET
Damhead Creek		T_DAMC-1	CCGT	259	2000	-121.7	118.7	902.5	DAMC40	Z15	NGET
Deanie	1		Hydro	19		0	0	71	DEAN80	Z1	SHETL
Deanie	2		Hydro	19		0	0	71	DEAN80	Z1	SHETL
Deeside		T_DEEP-1	CCGT	89.5	1994	-85.4	73.3	696.9	DEES42	Z9	NGET
Deeside		T_DEEP-1	CCGT	163	1994	-85.4	73.3	696.9	DEES42	Z9	NGET
Deeside		T_DEEP-1	CCGT	148	1994	-67.4	101.2	598	DEES42	Z9	NGET
Derwent			CCGT	41	1994	-22.9	22.8	143.6	WILL10	Z11	NGET
Derwent			CCGT	41	1994	-22.9	22.8	143.6	WILL10	Z11	NGET
Derwent			CCGT	41	1994	-22.9	22.8	143.6	WILL10	Z11	NGET
Derwent			CCGT	46	1994	-21.8	17.6	143.6	WILL10	Z11	NGET
Derwent			CCGT	63	1994	-30.7	15.3	241.9	WILL10	Z11	NGET
Deucherin Hill	1		Wind	15		-3	-3	77	DEUC8W	Z3	SHETL
Didcot A	1	T_DIDC1	Dual Fuel	527	1973	-267	183.6	1853.9	DIDC42	Z13	NGET
Didcot A	2	T_DIDC2	Dual Fuel	527	1972	-258.1	202.4	1873.6	DIDC42	Z13	NGET
Didcot A	3	T_DIDC3	Large Coal	527	1973	-264	187.1	1884.2	DIDC41	Z13	NGET
Didcot A	4	T_DIDC4	Dual Fuel	527	1975	-266.9	183.8	1851.7	DIDC41	Z13	NGET
Didcot A GT		T_DIDC1G	OCGT	25	1968				DIDC42	Z13	NGET
Didcot A GT		T_DIDC2G	OCGT	25	1969				DIDC42	Z13	NGET
Didcot A GT		T_DIDC3G	OCGT	25	1969				DIDC41	Z13	NGET
Didcot A GT		T_DIDC4G	OCGT	25	1970				DIDC41	Z13	NGET
Didcot B		T_DIDCB5	CCGT	240.7	1996	-89.9	60.9	824	DIDC41	Z13	NGET
Didcot B		T_DIDCB5	CCGT	240.7	1996	-89.9	60.9	824	DIDC41	Z13	NGET
Didcot B		T_DIDCB5	CCGT	293.4	1996	-111.9	76.1	854.9	DIDC41	Z13	NGET
Didcot B		T_DIDCB6	CCGT	237.7	1997	-88.2	64.3	823.4	DIDC42	Z13	NGET
Didcot B		T_DIDCB6	CCGT	237.7	1997	-84	72.5	823.4	DIDC42	Z13	NGET
Didcot B		T_DIDCB6	CCGT	299.8	1997	-122	105.2	854.3	DIDC42	Z13	NGET
Dinorwig	1	T_DINO-1	Pumped Storage	274	1984	-139.9	90.1	1140.5	DINO40	Z9	NGET
Dinorwig	2	T_DINO-2	Pumped Storage	274	1984	-139.9	90.1	1140.5	DINO40	Z9	NGET
Dinorwig	3	T_DINO-3	Pumped Storage	274	1983	-139.9	90.1	1140.5	DINO40	Z9	NGET

Dinorwig	4	T_DINO-4	Pumped Storage	274	1984	-139.9	90.1	1140.5	DINO40	Z9	NGET
Dinorwig	5	T_DINO-5	Pumped Storage	274	1984	-139.9	90.1	1140.5	DINO40	Z9	NGET
Dinorwig	6	T_DINO-6	Pumped Storage	274	1984	-139.9	90.1	1140.5	DINO40	Z9	NGET
Dounreay Wind (Caithness)	1		Wind	18	2005	-4.5	4.5	141	DOUW8W	Z1	SHETL
Drax	1	T_DRAXX-1	Large Coal	649	1974	-289	268.2	2177.8	DRAX41	Z8	NGET
Drax	2	T_DRAXX-2	Large Coal	649	1974	-288.5	268.8	2182.6	DRAX41	Z8	NGET
Drax	3	T_DRAXX-3	Large Coal	649	1976	-290.5	266.4	2121.9	DRAX41	Z8	NGET
Drax	4	T_DRAXX-4	Large Coal	649	1984	-271.1	271.7	2207.8	DRAX42	Z8	NGET
Drax	5	T_DRAXX-5	Large Coal	649	1985	-271.9	270.8	2198.8	DRAX42	Z8	NGET
Drax	6	T_DRAXX-6	Large Coal	649	1986	-271	271.9	2209.7	DRAX42	Z8	NGET
Drax		T_DRAXX-10G	OCGT		1981				N/A	Z8	NGET
Drax		T_DRAXX-12G	OCGT		1981				N/A	Z8	NGET
Drax		T_DRAXX-9G	OCGT	15	1973				N/A	Z8	NGET
Drone Hill			Wind	38	2008	-12.5	12.5	178	DRHI30	Z6	SPT
Drumderg Wind (Dalrulzion)	1		Wind	16	2007	-5.3	5.3	90	DRUW81	Z4	SHETL
Drumderg Wind (Dalrulzion)	2		Wind	16	2007	-5.3	5.3	90	DRUW82	Z4	SHETL
Dun Law	1		Wind	29.8	2008	-13.6	15.4	175.8	DUNE30	Z6	SPT
Dungeness B	21	T_DNGB21	Nuclear AGR	541	1985	-286.4	315	2224	DUNG40	Z15	NGET
Dungeness B	22	T_DNGB22	Nuclear AGR	541	1989	-297.8	308.6	2355.6	DUNG40	Z15	NGET
Earlsburn	1		Wind	35	2006	-13.4	14.8	198.8	EARB30	Z6	SPT
Edinbane Wind	1		Wind	42	2008	-26.4	10.5	156	EDIN10	Z1	SHETL
Eggborough	1	T_EGGPS-1	Large Coal	483	1968	-144.6	209.1	1648	EGGB42	Z8	NGET
Eggborough	2	T_EGGPS-2	Large Coal	483	1968	-150.6	217.1	1588.2	EGGB42	Z8	NGET
Eggborough	3	T_EGGPS-3	Large Coal	483	1968	-144.1	164.7	1637.5	EGGB41	Z8	NGET
Eggborough	4	T_EGGPS-4	Large Coal	483	1969	-148.2	184.3	1605.3	EGGB41	Z8	NGET
Eggborough			OCGT		1967				EGGB42	Z8	NGET
Eggborough			OCGT		1968				EGGB41	Z8	NGET
Eredine Forest Wind (Argyll)	1		Wind	30	2008	-9.9	9.9	130	ERED8W	Z3	SHETL
Errochty	1	ERRO-1	Hydro	25		-1.7	10	109	ERRO10	Z4	SHETL

Errochty	2	ERRO-2	Hydro	25		0	12.1	154	ERRO82	Z4	SHETL
Errochty	3	ERRO-3	Hydro	25		-1.7	10	109	ERRO10	Z4	SHETL
Exxon Mosmorran	1		CHP	16		0	0	16	MOSM10	Z5	SPT
Fairburn Wind	1		Wind	42	2009	-10.5	10.5	276	FAWI80	Z1	SHETL
Farr Windfarm (Tomatin)	1		Wind	46	2005	-29	1	240	FAAR1Q	Z1	SHETL
Farr Windfarm (Tomatin)	2		Wind	46	2005	-29	1	240	FAAR1R	Z1	SHETL
Fasnakyle	1	FASN-1	Hydro	23		-3	-3	74	FASN10	Z1	SHETL
Fasnakyle	1	FASN-1	Hydro	23		-3	-3	74	FASN10	Z1	SHETL
Fasnakyle	2	FASN-2	Hydro	23		-2.5	-2.5	80	FASN10	Z1	SHETL
Fasnakyle	2	FASN-2	Hydro	23		-2.5	-2.5	80	FASN10	Z1	SHETL
Fasnakyle	3	FASN-3	Hydro	23		-1.6	-1.6	93	FASN10	Z1	SHETL
Fasnakyle	3	FASN-3	Hydro	23		-1.6	-1.6	93	FASN10	Z1	SHETL
Fawley	1	T_FAWL1	Oil	500	1969	-156.7	199	1603.6	FAWL40	Z16	NGET
Fawley	3	T_FAWL3	Oil	500	1970	-154.3	201.3	1601.4	FAWL40	Z16	NGET
Fawley		T_FAWL1G	OCGT	17	1969				FAWL40	Z16	NGET
Fawley		T_FAWL2G	OCGT	23	1969				FAWL40	Z16	NGET
Fawley		T_FAWL3G	OCGT	17	1970				FAWL40	Z16	NGET
Fawley		T_FAWL4G	OCGT	8	1970				FAWL40	Z16	NGET
Fawley CHP	1		OCGT	158	1999	-90	19.7	368.2	FAWL10	Z16	NGET
Ferrybridge C	1	T_FERR-1	Large Coal	490	1966	-155.3	195.9	1544.2	FERR23	Z8	NGET
Ferrybridge C	2	T_FERR-2	Large Coal	490	1967	-154.8	196.6	1513.9	FERR22	Z8	NGET
Ferrybridge C	3	T_FERR-3	Large Coal	490	1967	-154.2	197.3	1519.4	FERR22	Z8	NGET
Ferrybridge C	4	T_FERR-4	Large Coal	490	1968	-150.5	196.1	1540	FERR23	Z8	NGET
Ferrybridge C		T_FERR-5G	OCGT	10.5					FERR21	Z8	NGET
Ferrybridge C		T_FERR-8G	OCGT	10.5	1967				FERR23	Z8	NGET
Ffestiniog	1	T_FFES-1	Pumped Storage	90	1961	-38.8	21.2	375.6	FFES21	Z9	NGET
Ffestiniog	2	T_FFES-2	Pumped Storage	90		-38.8	21.2	375.6	FFES21	Z9	NGET
Ffestiniog	3	T_FFES-3	Pumped Storage	90	1963	-38.8	21.2	375.6	FFES22	Z9	NGET
Ffestiniog	4	T_FFES-4	Pumped Storage	90		-38.8	21.2	375.6	FFES22	Z9	NGET
Fiddlers Ferry	1	T_FIDL-1	Large Coal	485	1971	-166.6	211.3	1649.6	FIDF21	Z9	NGET
Fiddlers Ferry	2	T_FIDL-2	Large Coal	485	1972	-166.5	213.8	1649.7	FIDF22	Z9	NGET
Fiddlers Ferry	3	T_FIDL-3	Large Coal	485	1972	-172	229.6	1659.7	FIDF23	Z9	NGET
Fiddlers Ferry	4	T_FIDL-4	Large Coal	506	1973	-164.3	120.6	1693.3	FIDF24	Z9	NGET
Fiddlers Ferry		T_FIDL-2G	OCGT		1969				FIDF22	Z9	NGET
Fiddlers Ferry		T_FIDL-3G	OCGT		1970				FIDF23	Z9	NGET

Fife	1	FIFE-1	CCGT	70.5	2000	-49.2	46.2	268	FIFE10	Z5	SPT
Fife	2		CCGT	52.5	2000	-43.4	21	170	FIFE1B	Z5	SPT
Finlarig	1	FINL-1	Hydro	17		-6.2	9.2	108	FINL1Q	Z4	SHETL
Flotta			Gas	10					THSO8E	Z1	SHETL
Foyers	1	FOYE-1	Pumped Storage	150		-103.6	20.3	600	FOYE20	Z1	SHETL
Foyers	2	FOYE-2	Pumped Storage	150		-103.1	20.7	606	FOYE20	Z1	SHETL
Glenmoriston	1		Hydro	18.5		-3.5	9.9	180	GLEN1Q	Z1	SHETL
Glenmoriston	2		Hydro	18.5		0	6.9	75	GLEN80	Z1	SHETL
Glens of Foundland	1		Wind	13	2005	-4.2	4.2	85	GLOF81	Z2	SHETL
Glens of Foundland	2		Wind	13	2005	-4.2	4.2	85	GLOF82	Z2	SHETL
Gordonbush Wind	1		Wind	88	2009	-28.9	28.9	257	STRB20	Z1	SHETL
Grain	1	T_GRAI-1	Oil	650	1982	-237.1	242.4	1800.8	GRAI40	Z15	NGET
Grain	2	T_GRAI-2	Oil	0	1979	-237.1	242.4	1800.8	GRAI40	Z15	NGET
Grain	3	T_GRAI-3	Oil	0	1982	0	0		GRAI40	Z15	NGET
Grain	4	T_GRAI-4	Oil	650	1984	0	0		GRAI40	Z15	NGET
Grain		T_GRAI1G	OCGT	55	1979				GRAI40	Z15	NGET
Grain		T_GRAI2G	OCGT	0	1978				GRAI40	Z15	NGET
Grain		T_GRAI3G	OCGT	0	1979				GRAI40	Z15	NGET
Grain		T_GRAI4G	OCGT	0	1980				GRAI40	Z15	NGET
Grain		T_GRAI5G	OCGT	0	1982				GRAI40	Z15	NGET
Grangemouth CHP	1	BPGRD-1	CHP	120		-84.1	51.2	492	BPGR34	Z6	SPT
Grangemouth CHP	1		CHP			0	0	422	BPGR34	Z6	SPT
Grangemouth CHP	2		CHP			0	12.9	263	BPGR34	Z6	SPT
Grangemouth CHP	2		CHP			0	0	74	BPGR34	Z6	SPT
Grangemouth CHP	3		CHP			0	12.9	263	BPGR34	Z6	SPT
Grangemouth CHP	3		CHP			0	0	190	BPGR34	Z6	SPT
Grangemouth CHP	4		CHP			0	12.9	263	BPGR34	Z6	SPT
Grangemouth CHP	5		CHP			0	12.9	263	BPGR34	Z6	SPT
Grangemouth CHP	6		CHP			0	12.9	263	BPGR34	Z6	SPT
Grangemouth CHP	7		CHP			4	4	261	BPGR34	Z6	SPT
Grangemouth CHP	8		CHP			4	4	261	BPGR34	Z6	SPT
Great Yarmouth	1		CCGT	420	2000	-208.6	184.1	1203.6	NORW10	Z12	NGET
Greater Gabbard			Offshore Wind	500	2009	-164	164		SIZE11/12		NGET
Grudie Bridge	1		Hydro	11		0	3.2	67	GRUB81	Z1	SHETL
Grudie Bridge	2		Hydro	11		0	0	78	GRUB81	Z1	SHETL

Hadyard Hill	1		Wind	117	2005	-7	-7	635.5	HADH30	Z6	SPT
Hartlepool	1	T_HRTL-1	Nuclear AGR	604	1989	-299	258.3	2043.4	HATL20	Z7	NGET
Hartlepool	2	T_HRTL-2	Nuclear AGR	604	1989	-296.8	244.8	2043.4	HATL20	Z7	NGET
Heysham 1	1	T_HEYM11	Nuclear AGR	607	1989	-289.2	286.3	2224	HEYS40	Z9	NGET
Heysham 1	2	T_HEYM12	Nuclear AGR	596	1989	-288.7	292.6	2196.2	HEYS40	Z9	NGET
Heysham 2	7	T_HEYM27	Nuclear AGR	601	1989	-266.2	269.2	2404.1	HEYS40	Z9	NGET
Heysham 2	8	T_HEYM28	Nuclear AGR	603	1989	-264.6	265.7	2417.9	HEYS40	Z9	NGET
Hinkley Point B	7	T_HINB-7	Nuclear AGR	644	1978	-248.6	202.8	2023	HINP40	Z17	NGET
Hinkley Point B	8	T_HINB-8	Nuclear AGR	617	1976	-290.8	193.5	2078.5	HINP40	Z17	NGET
Houstary Wind Dunbeath	1		Wind	14	2004	0	0	49	DUBE3D	Z1	SHETL
Hunterston	7	HUNB-7	Nuclear AGR	545		-145.9	273.8	1976	HUER40	Z6	SPT
Hunterston	8	HUNB-8	Nuclear AGR	545		-145.4	104.2	1983	HUER40	Z6	SPT
Immingham CHP stage 1			CCGT	244	2004	-122.4	118.5	844	HUMR40	Z8	NGET
Immingham CHP stage 1			CCGT	262	2004	-122.4	118.5	844	HUMR40	Z8	NGET
Immingham CHP stage 1			CCGT	117	2004	-53.5	54.6	439	HUMR40	Z8	NGET
Immingham CHP stage 1			CCGT	117	2004	-53.5	54.6	439	HUMR40	Z8	NGET
Immingham CHP stage 2			CCGT	227	2008	-114	148.1	828.9	HUMR40	Z8	NGET
Immingham CHP stage 2			CCGT	227	2008	-114	148.1	828.9	HUMR40	Z8	NGET
Immingham CHP stage 2			CCGT	106	2008	-52.5	55.6	439	HUMR40	Z8	NGET
Indian Queens	1	T_INDQ-1	OCGT	140	1996	-54.9	115.9	656.3	INDQ40	Z17	NGET
Insch Wind	1		Wind	10	2005	-1.5	1.5	63	KEIT80	Z2	SHETL
Inverawe	1		Hydro	25		-2	-2	72	INAW3Q	Z3	SHETL
Invergarry	1	CAS-GAR01	Hydro	20		-1.6	-1.6	65	INGA1Q	Z1	SHETL
Ironbridge	1	T_IRNPS-1	Large Coal	482	1970	-165.2	208.5	1539.1	IRON40	Z11	NGET
Ironbridge	2	T_IRNPS-2	Large Coal	482	1970	-159.5	206.3	1522.7	IRON40	Z11	NGET
Ironbridge			OCGT		1967				IRON40	Z11	NGET
Ironbridge			OCGT		1967				IRON40	Z11	NGET
Keadby		T_KEAD-1	CCGT	245	1994	-109.5	96.5	772.1	KEAP41	Z8	NGET
Keadby		T_KEAD-1	CCGT	245	1994	-106.2	110.9	805.6	KEAP42	Z8	NGET
Keadby		T_KEAD-1	CCGT	245	1994	-113.7	103.3	781.6	KEAP42	Z8	NGET
Keadby		T_KEADGT3	CCGT						N/A	Z8	NGET

Keadby		T_KEADGT3	CCGT						N/A	Z8	NGET
Keadby		T_KEADGT3	CCGT						N/A	Z8	NGET
Kilbraur Wind Farm Stage 1	1		Wind	47.5	2007	-12.2	17.9	441	STRB8W	Z1	SHETL
Kilbraur Wind Farm Stage 2	1		Wind	19.5	2009	-12.2	17.9	441	STRB8W	Z1	SHETL
Killingholme 1		T_KILLPG-1	CCGT	0	1992	-69.7	66.9	584.6	KILL40	Z8	NGET
Killingholme 1		T_KILLPG-1	CCGT	0	1992	-68.1	68.7	593.8	KILL40	Z8	NGET
Killingholme 1		T_KILLPG-1	CCGT	0	1992	-73.6	79.6	658.2	KILL40	Z8	NGET
Killingholme 1		T_KILLPG-2	CCGT	0	1992	-69.5	67	587	KILL40	Z8	NGET
Killingholme 1		T_KILLPG-2	CCGT	0	1992	-69.5	67	573.5	KILL40	Z8	NGET
Killingholme 1		T_KILLPG-2	CCGT	0	1992	-73.6	79.6	658.2	KILL40	Z8	NGET
Killingholme 2		T_KILNS-1	CCGT	144.6	1993	-69	57.3	638.2	KILL40	Z8	NGET
Killingholme 2		T_KILNS-1	CCGT	144.6	1993	-69	57.3	637.6	KILL40	Z8	NGET
Killingholme 2		T_KILNS-1	CCGT	144.6	1993	-69	57.3	628.6	KILL40	Z8	NGET
Killingholme 2		T_KILNS-1	CCGT	231.2	1993	-106.7	104.7	773.1	KILL40	Z8	NGET
Kilmorack	1		Hydro	10		-1.8	-1.8	93	KIOR1Q	Z1	SHETL
Kilmorack	2		Hydro	10		0	0	39	KIOR80	Z1	SHETL
Kings Lynn			CCGT	340	1996	-172.8	128.9	1109.5	KINL1A	Z12	NGET
Kings Lynn			CCGT						KLYP11	Z12	NGET
Kings Lynn			CCGT						KLYP11	Z12	NGET
Kingsnorth	1	T_KINO-1	Dual Fuel	485	1970	-131.9	196	1845.4	KINO40	Z15	NGET
Kingsnorth	2	T_KINO-2	Dual Fuel	485	1971	-131.8	196.2	1848.1	KINO40	Z15	NGET
Kingsnorth	3	T_KINO-3	Dual Fuel	485	1972	-128.4	200.7	1897.1	KINO40	Z15	NGET
Kingsnorth	4	T_KINO-4	Dual Fuel	485	1973	-132.5	195.3	1837.9	KINO40	Z15	NGET
Kingsnorth		T_KINO1G	OCGT	13	1967				KINO40	Z15	NGET
Kingsnorth		T_KINO4G	OCGT	13	1967				KINO40	Z15	NGET
Kinlochleven	1		Hydro	10	2001	-3.5	3.4	35	KILO3Q	Z1	SHETL
Kinlochleven	2		Hydro	10	2001	-3.5	3.4	35	KILO3Q	Z1	SHETL
Kinlochleven	3		Hydro	10	2001	-3.5	3.4	35	KILO3Q	Z1	SHETL
Lairg - Achany WF	1		Wind	62	2009	-24.6	32.7	299.5	LAIR3W	Z1	SHETL
Langage stage 1			CCGT	452.5	2008	-196.7	178.5	1259	LANG40	Z17	NGET
Langage stage 1			CCGT	452.5	2008	-196.7	178.5	1259	LANG40	Z17	NGET
Little Barford		T_LBAR-1	CCGT	210	1994	-109.5	90.1	713.1	LITB40	Z12	NGET
Little Barford		T_LBAR-1	CCGT	210	1994	-109.2	90.3	715.3	LITB40	Z12	NGET
Little Barford		T_LBAR-1	CCGT	245	1994	-117.4	115.7	794.2	LITB40	Z12	NGET
Littlebrook D	1	T_LITTD1	Oil	685	1982	-261.2	264	1797	LITT40	Z14	NGET

Littlebrook D	2	T_LITTD2	Oil	685	1983	-260.8	264.5	1801.4	LITT40	Z14	NGET
Littlebrook D	3	T_LITTD3	Oil	0	1984	0	0	1799.4	LITT40	Z14	NGET
Littlebrook D		T_LITTD1G	OCGT	35	1980				LITT40	Z14	NGET
Littlebrook D		T_LITTD2G	OCGT	35	1981				LITT40	Z14	NGET
Littlebrook D		T_LITTD3G	OCGT	35	1982				LITT40	Z14	NGET
Livishie	1		Hydro	15		0	0	96	LIVI80	Z1	SHETL
Lochay	1		Hydro	22.5		-2	-2	71	LOCH10	Z4	SHETL
Lochay	2		Hydro	22.5		-1.9	-1.9	71	LOCH10	Z4	SHETL
Longannet	1	LOAN-1	Large Coal	576		-230	118	2313	LOAN20	Z5	SPT
Longannet	3	LOAN-2	Large Coal	576		-228	120	2313	LOAN20	Z5	SPT
Longannet	5	LOAN-3	Large Coal	576		-209.5	232.9	2321	LOAN20	Z5	SPT
Longannet	7	LOAN-4	Large Coal	576		-210	232.2	2313	LOAN20	Z5	SPT
Longpark			Wind	38	2009	-12.5	12.5	178	LOPA30	Z6	SPT
Luichart	1		Hydro	17		-1.1	-1.1	72	LUIC1Q	Z1	SHETL
Luichart	2		Hydro	17		-1.1	-1.1	72	LUIC1R	Z1	SHETL
Lynemouth	1		Small Unit Coal	131	1971	-72	28	64.7	ALCA10	Z7	NGET
Lynemouth	2		Small Unit Coal	131	1971	-72	28	64.7	ALCA10	Z7	NGET
Lynemouth	3		Small Unit Coal	131	1971	-72	28	64.7	ALCA10	Z7	NGET
Lynes Common			OCGT	49.9						Z16	NGET
Marchwood	1		CCGT	324	2008	-138.2	133.8	957.2	MAWO40	Z16	NGET
Marchwood	2		CCGT		2008				MAWO40	Z16	NGET
Marchwood	3		CCGT	324	2008	-138.2	133.8	957.2	MAWO40	Z16	NGET
Marchwood	4		CCGT		2008				MAWO40	Z16	NGET
Marchwood	5		CCGT	288	2008	-134.2	114.9	869.5	MAWO40	Z16	NGET
Medway		T_MEDP-1	CCGT	226.7	1995	-120.1	109.1	695.5	MEDW40	Z15	NGET
Medway		T_MEDP-1	CCGT	226.7	1995	-118.9	110.9	696.1	MEDW40	Z15	NGET
Medway		T_MEDP-1	CCGT	226.7	1995	-112.6	121.3	694	MEDW40	Z15	NGET
Millennium Wind (Ceannacroc) Stage 1	1		Wind	40	2007	-13	13	185	MILW1Q	Z1	SHETL
Millennium Wind (Ceannacroc) Stage 2	1		Wind	10	2008	-3.3	3.3	185	MILW1Q	Z1	SHETL
Millennium Wind (Ceannacroc) Stage 3	1		Wind	15	2009	-4.9	4.9	185	MILW1Q	Z1	SHETL
Minsca Risp Hill	1		Wind	38	2007	-1.6	-1.6	149.8	MINS80	Z6	SPT
Mossford			Hydro	18.7						Z1	SHETL
Nant Loch Nant Hydro	1		Hydro	15		-5.6	4	42	LOCN1Q	Z1	SHETL
Novar	1		Wind	19		-1	-1	85	NOVA80	Z1	SHETL

Oldbury	1	T_OLDS1	Nuclear Magnox	228	1967	-118.1	153.7	1150	OLDS11	Z13	NGET
Oldbury	2	T_OLDS2	Nuclear Magnox	242	1968	-108.8	148.6	1154.6	OLDS12	Z13	NGET
Orrin	1		Hydro	18		-1.6	-1.6	67	ORRI1R	Z1	SHETL
Paul's Hill Aberlour	1		Wind	56	2005	-13	13	304	PAUH80	Z1	SHETL
Peterborough			CCGT		1993	-72.1	53.6	449.1	WALP11	Z12	NGET
Peterborough			CCGT		1993	-72.1	53.6	449.1	WALP13	Z12	NGET
Peterborough			CCGT	405	1993	-82.2	66.9	449.1	WALP11	Z12	NGET
Peterhead	1		CCGT	660		-134.6	291.8	1789	PEHE2S	Z2	SHETL
Peterhead	2		Dual Fuel Oil/ Gas	660		-135	291.2	1786	PEHE2T	Z2	SHETL
Peterhead	3		OCGT	120.5		-72.3	66.2	523	PEHE12	Z2	SHETL
Peterhead	4		OCGT	120.5		-72.5	66	520	PEHE13	Z2	SHETL
Peterhead	11		CCGT	266		-125.1	118	834	PEHE2U	Z2	SHETL
Peterhead	12		CCGT	266		-125.1	118	834	PEHE2V	Z2	SHETL
Peterhead	13		CCGT	266		-125.1	118	834	PEHE2W	Z2	SHETL
Pitlochry			Hydro	15						Z3	SHETL
Quoich	1		Hydro	18		-1.1	4.7	75	QUOI10	Z1	SHETL
Rannoch	1		Hydro	14.7		0	32.7	1024	RANN81	Z4	SHETL
Rannoch	2		Hydro	14.7		0	10.9	114	RANN81	Z4	SHETL
Rannoch	3		Hydro	14.7		0	10.9	114	RANN81	Z4	SHETL
Ratcliffe on Soar	1	T_RATS-1	Large Coal	500	1968	-148.1	170	1599.9	RATS41	Z11	NGET
Ratcliffe on Soar	2	T_RATS-2	Large Coal	500	1969	-129.3	193.2	1812.7	RATS41	Z11	NGET
Ratcliffe on Soar	3	T_RATS-3	Large Coal	500	1969	-129.3	193.1	1811	RATS42	Z11	NGET
Ratcliffe on Soar	4	T_RATS-4	Large Coal	500	1970	-79.5	177.6	1660	RATS42	Z11	NGET
Ratcliffe on Soar			OCGT	0	1966				RATS41	Z11	NGET
Ratcliffe on Soar		T_RATSGT-2	OCGT	10	1967				RATS41	Z11	NGET
Ratcliffe on Soar			OCGT	0	1967				RATS42	Z11	NGET
Ratcliffe on Soar		T_RATGT-4	OCGT	11	1968				RATS42	Z11	NGET
Rocksavage	1	T_ROCK-1	CCGT	270	1997	-156.8	176.2	1427.2	ROCK40	Z9	NGET
Rocksavage	2	T_ROCK-1	CCGT	270	1997	-156.8	176.2	1427.2	ROCK40	Z9	NGET
Rocksavage	3	T_ROCK-1	CCGT	270	1997	-151	179	1427.2	ROCK40	Z9	NGET
Roosecote			CCGT	169	1991	-75.9	77	696.3	ROOS10	Z9	NGET
Roosecote			CCGT	60	1991	-25.9	34.6	242.5	ROOS10	Z9	NGET
Rothes Biopower Plant			Biomass	52	2008			251.6	ROBP3A	Z5	SPT
Rugeley B	6	T_RUGPS-6	Large Coal	498	1972	-149.6	190.1	1633.3	RUGE40	Z11	NGET
Rugeley B	7	T_RUGPS-7	Large Coal	498	1972	-148.6	191.3	1638.5	RUGE40	Z11	NGET

Rugeley B		T_RUGGT-6	OCGT	22	1969				RUGE40	Z11	NGET
Rugeley B		T_RUGGT-7	OCGT	0	1969				RUGE40	Z11	NGET
Rye House		T_RYHPS-1	CCGT	178	1993	-68.2	66.1	505.1	RYEH40	Z14	NGET
Rye House		T_RYHPS-1	CCGT	178	1993	-66.4	68.3	523.9	RYEH40	Z14	NGET
Rye House		T_RYHPS-1	CCGT	178	1993	-68.3	66	504.1	RYEH40	Z14	NGET
Rye House		T_RYHPS-1	CCGT	295	1993	-121.1	78.6	822.9	RYEH40	Z14	NGET
Saltend		T_SCCL-1	CCGT	367	1999	-197.8	173.9	1209.5	SAES20	Z8	NGET
Saltend		T_SCCL-2	CCGT	367	1999	-197.8	173.9	1209.5	SAES20	Z8	NGET
Saltend		T_SCCL-3	CCGT	367	1999	-197.8	173.9	1209.5	SAES20	Z8	NGET
Scunthorpe	1		CCGT	98	2007	-40	51	697.3	BRIG10	Z8	NGET
Scunthorpe	2		CCGT	98	2007	-40	51	689.7	BRIG10	Z8	NGET
Scunthorpe	3		CCGT	98	2007	-42.6	47.7	525.6	BRIG10	Z8	NGET
Seabank		T_SEAB-1	CCGT	273.3	1998	-130.7	95.5	1080.8	SEAB40	Z13	NGET
Seabank		T_SEAB-1	CCGT	273.3	1998	-130.7	95.5	1080.8	SEAB40	Z13	NGET
Seabank		T_SEAB-2	CCGT	414	2000	-210.1	136.8	1345.4	SEAB40	Z13	NGET
Seabank		T_SEAB-1	CCGT	273.3	1998	-122	110.2	1080.8	SEAB40	Z13	NGET
Sellafield CHP			CCGT	37	1993	-18.9	22.7	170.3	SEFI10	Z9	NGET
Sellafield CHP			CCGT	37	1993	-20	19.2	189.1	SEFI10	Z9	NGET
Sellafield CHP			CCGT	37	1993	-20	19.2	170.4	SEFI10	Z9	NGET
Sellafield CHP			CCGT	44	1993	-21.2	28.2	240.4	SEFI10	Z9	NGET
Severn Power Stage 1			CCGT	425	2009	-208.1	193.3	1087	USKM20	Z13	NGET
Shin			Hydro	18.6						Z1	SHETL
Shoreham			CCGT	420	2000	-225.5	219.1	1072.3	SERX10	Z16	NGET
Shotton			CCGT	70	2001	-54.5	53.3	297.3	SHOT10	Z9	NGET
Shotton			CCGT	70	2001	-54.4	54.2	296.6	SHOT10	Z9	NGET
Shotton			CCGT	70	2001	-52.6	56.7	295.7	SHOT10	Z9	NGET
Sizewell B	3	T_SIZB-1	Nuclear PWR	600	1994	-289.2	287.3	2140.8	SIZE40	Z12	NGET
Sizewell B	4	T_SIZB-2	Nuclear PWR	600	1994	-281.8	286.2	2133.9	SIZE40	Z12	NGET
Sloy	1	SLOY-1	Hydro	33		-11.8	8.9	101	SLOY13	Z3	SHETL
Sloy	2	SLOY-2	Hydro	40		-11.8	8.9	102	SLOY14	Z3	SHETL
Sloy	3	SLOY-3	Hydro	40		-11.4	9.3	101	SLOY15	Z3	SHETL
Sloy	4	SLOY-4	Hydro	40		-11.6	15.6	100	SLOY16	Z3	SHETL
South Humber Bank		T_SHBA-1	CCGT	169	1996	-76	76.9	636.9	SHBA40	Z8	NGET
South Humber Bank		T_SHBA-1	CCGT	169	1996	-80.4	70.8	636	SHBA40	Z8	NGET
South Humber Bank		T_SHBA-1	CCGT	169	1996	-81.3	69.2	637.5	SHBA40	Z8	NGET

South Humber Bank		T_SHBA-1	CCGT	262	1996	-126.8	119.5	752.4	SHBA40	Z8	NGET
South Humber Bank		T_SHBA-2	CCGT	174	1998	-79.2	68.1	658.2	SHBA40	Z8	NGET
South Humber Bank		T_SHBA-2	CCGT	174	1998	-79.3	68	657.3	SHBA40	Z8	NGET
South Humber Bank		T_SHBA-2	CCGT	168	1998	-77.8	80.7	625.6	SHBA40	Z8	NGET
Spalding		T_SPLN-1	CCGT	252	2004	-186.5	141.4	843.9	SPLN40	Z10	NGET
Spalding		T_SPLN-1	CCGT	252	2004	-185	146.5	843.9	SPLN40	Z10	NGET
Spalding		T_SPLN-1	CCGT	366	2004	-242.3	231.7	904.5	SPLN40	Z10	NGET
St Fillians	1		Hydro	17		-2	7.7	71	SFIL1Q	Z4	SHETL
Staythorpe C stage 1			CCGT	425	2009	-215.4	303.4	1143.5	STAY41	Z10	NGET
Staythorpe C stage 2			CCGT	425	2009	-215.4	303.4	1143.5	STAY41	Z10	NGET
Staythorpe C stage 3			CCGT	425	2009	-215.4	303.4	1143.5	STAY42	Z10	NGET
Staythorpe C stage 4			CCGT	425	2009	-215.4	303.4	1143.5	STAY42	Z10	NGET
Steven's Croft	1		Biomass	45	2006	-14.2	12.4	175.2	STCR80	Z6	SPT
Stoneywood Mills	1		CHP	12		0	0		STOM30	Z2	SHETL
Sutton Bridge	1	T_SUTB-1	CCGT	266.7	1998	-131.1	94.9	886.8	SUTB4A	Z12	NGET
Sutton Bridge	2	T_SUTB-1	CCGT	266.7	1998	-131.1	94.9	886.8	SUTB4A	Z12	NGET
Sutton Bridge	3	T_SUTB-1	CCGT	266.6	1998	-122.6	119.7	886.8	SUTB4A	Z12	NGET
Tangy	1		Wind	13	2002	-3	-3	96	TANG80	Z3	SHETL
Taylors Lane	2	E_TAYL2G	OCGT	72	1981	-28.9	29.6	317.5	WISD10	Z14	NGET
Taylors Lane	3	E_TAYL3G	OCGT	72	1979	-29.9	27.9	325	WISD10	Z14	NGET
Teesside		T_TESI-1	CCGT	153.5	1992	-74.8	42.3	556.6	GRST21	Z7	NGET
Teesside		T_TESI-1	CCGT	153.5	1992	-74.9	42.1	556.6	GRST21	Z7	NGET
Teesside		T_TESI-1	CCGT	153.5	1992	-74.9	42.1	556.6	GRST21	Z7	NGET
Teesside		T_TESI-1	CCGT	153.5	1992	-75.1	41.9	556.6	GRST21	Z7	NGET
Teesside		T_TESI-1	CCGT	153.5	1992	-166.1	129.4	1197.8	GRST21	Z7	NGET
Teesside		T_TESI-2	CCGT	153.5	1992	-74.8	42.3	556.6	GRST22	Z7	NGET
Teesside		T_TESI-2	CCGT	153.5	1992	-75.1	41.9	556.6	GRST22	Z7	NGET
Teesside		T_TESI-2	CCGT	153.5	1992	-74.8	42.3	556.6	GRST22	Z7	NGET
Teesside		T_TESI-2	CCGT	153.5	1992	-74.9	42.1	556.6	GRST22	Z7	NGET
Teesside		T_TESI-2	CCGT	323.5	1992	-166.6	128.7	1197.8	GRST22	Z7	NGET
Teesside		T_TESI-2	CCGT	323.5	1992	-166.6	128.7	1197.8	GRST22	Z7	NGET
Thanet Offshore Windfarm			Offshore Wind	300	2009	-98.6	98.6		CANT11/2	Z15	NGET
Tilbury B	7	T_TILB-7	Medium Coal	0	1968	0	0	1295.8	TILB21	Z15	NGET
Tilbury B	8	T_TILB-8	Medium Coal	368	1972	-114.9	108.3	1300.7	TILB21	Z15	NGET
Tilbury B	9	T_TILB-9	Medium Coal	368	1972	-113.5	110	1320.6	TILB22	Z15	NGET
Tilbury B	10	T_TILB-10	Medium Coal	368	1970	-111.3	120.8	1262	TILB22	Z15	NGET

Tilbury B		T_TILB-10G	OCGT	0	1965				TILB22	Z15	NGET
Tilbury B		T_TILB-7G	OCGT	0	1965				TILB21	Z15	NGET
Tilbury B		T_TILB-8G	OCGT	13	1965				TILB21	Z15	NGET
Tilbury B		T_TILB-9G	OCGT	13	1965				TILB22	Z15	NGET
Toddleburn	1		Wind	36	2009	-14	15	175.8	TODD80	Z6	SPT
Tongland	1		Hydro	11					TONG80	Z6	SPT
Tongland	2		Hydro	11					TONG80	Z6	SPT
Tongland	3		Hydro	11					TONG80	Z6	SPT
Tormywheel			Wind	32	2009	-10.5	10.5	152	TORM3A/3B	Z6	SPT
Torness	1	TORN-1	Nuclear AGR	600		-272.5	296.9	1769.2	TORN40	Z6	SPT
Torness	2	TORN-2	Nuclear AGR	600		-272.5	296.9	1769.2	TORN40	Z6	SPT
Torr Achilty			Hydro	15						Z1	SHETL
Tullo Wind Laurencekirk	1		Wind	14	2009	-4.6	4.6	75	BRID30	Z1	SHETL
Tummel Bridge	1		Hydro	17		0	0	475	TUMB81	Z4	SHETL
Tummel Bridge	2		Hydro	17		0	0	119	TUMB81	Z4	SHETL
Uskmouth	1	T_USKM-13	Small Unit Coal	121	2000	-66.8	54	513.8	USKM10	Z13	NGET
Uskmouth	2	T_USKM-14	Small Unit Coal	121	2000	-66.8	54	513.8	USKM10	Z13	NGET
Uskmouth	3	T_USKM-15	Small Unit Coal	121	2000	-66.8	54	513.8	USKM10	Z13	NGET
West Burton	1	T_WBUPS-1	Large Coal	483	1967	-176.1	202	1537.9	WBUR40	Z10	NGET
West Burton	2	T_WBUPS-2	Large Coal	503	1967	-178.8	166.1	1533	WBUR40	Z10	NGET
West Burton	3	T_WBUPS-3	Large Coal	503	1967	-179.1	165.8	1530.5	WBUR40	Z10	NGET
West Burton	4	T_WBUPS-4	Large Coal	483	1968	-176.6	201.4	1533.4	WBUR40	Z10	NGET
West Burton		T_WBUGT-1	OCGT	7.5	1966				WBUR40	Z10	NGET
West Burton			OCGT		1966				WBUR40	Z10	NGET
West Burton			OCGT		1967				WBUR40	Z10	NGET
West Burton		T_WBUGT-1	OCGT	7.5	1968				WBUR40	Z10	NGET
West Burton B Stage 1			CCGT	435	2009	-226	184.1	1141.6	WBUR40	Z10	NGET
Whitelee	1		Wind	75.9	2007	-36.9	39.2	482.8	WHIL8A	Z6	SPT
Whitelee	2		Wind	218.5	2008	-36.9	39.2	482.8	WHIL8B	Z6	SPT
Whitelee	3		Wind	28.6	2009	-36.9	39.2	482.8	WHIL8C	Z6	SPT
Wilton			CCGT	38	2006				WILT2	Z7	NGET
Wilton			CCGT	12	2007				WILT2	Z7	NGET
Wylfa	1	WYLF-1	Nuclear Magnox	245	1971	-117.2	137.3	1025.4	WYLF40	Z9	NGET
Wylfa	2	WYLF-2	Nuclear Magnox	245	1971	-115.9	133.8	997.7	WYLF40	Z9	NGET

Wylfa	3	WYLF-3	Nuclear Magnox	245	1971	-114.8	132.8	1025.4	WYLF40	Z9	NGET
Wylfa	4	WYLF-4	Nuclear Magnox	245	1971	-110.7	135.6	1039.2	WYLF40	Z9	NGET

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Table 3.7 - Changes in Power Station Capacity (TEC (MW)), from 2005/06 to 2015/16

Station Name	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Licensee	Plant Type	SYS Study Zone	Consents	Under Construction
Black Law	134											SPT	Onshore Wind	Z6		
Hadyard Hill	117											SPT	Onshore Wind	Z6		
Farr Wind Farm, Tomatin	92											SHETL	Onshore Wind	Z1		
Glens of Foudland Wind (SRO)	26											SHETL	Onshore Wind	Z2		
Boyndie Wind	14											SHETL	Onshore Wind	Z2		
Paul's Hill Wind	14											SHETL	Onshore Wind	Z1		
Dummuies Windfarm, Insch	10											SHETL	Onshore Wind	Z2		
Boyndie Wind (Add. Cap.)	7											SHETL	Onshore Wind	Z2		
Wilton		38	12		10							NGET	CCGT	Z7		
Earlsburn		35										SPT	Onshore Wind	Z5		
Tangy (Add. Cap.)		6										SHETL	Onshore Wind	Z4		
Whitelee Stage 1			76									SPT	Onshore Wind	Z6		
Kilbraur (Strath Brora) Wind Farm Stage 1			48									SHETL	Onshore Wind	Z1		
Stevens Croft			45									SPT	Biomass	Z6		
Millenium Wind, Ceannacroc Stage 1			40									SHETL	Onshore Wind	Z1		
Minsca			38									SPT	Onshore Wind	Z6		
Drumderg Wind Farm, Dalrulzion			32									SHETL	Onshore Wind	Z3		
Dalswinton			30									SPT	Onshore Wind	Z6		
Ben Aketil Wind			21									SHETL	Onshore Wind	Z1		
Ben Aketil Wind (Add. Cap.)			7									SHETL	Onshore Wind	Z1		
Langage				905								NGET	CCGT	Z17		
Marchwood				900								NGET	CCGT	Z16		
Immingham Stage 2				601								NGET	CHP	Z8		
Whitelee Stage 2				218								SPT	Onshore Wind	Z6		
Glendoe, Fort Augustus Stage 1				52								SHETL	Hydro	Z1		
Aikengall				48								SPT	Onshore Wind	Z6		
An Suidhe				30								SHETL	Onshore Wind	Z4		
Ardkinglas, Clachan (SRO)				19								SHETL	Onshore Wind	Z4		

Millenium Wind, Ceannacroc Stage 2				10								SHETL	Onshore Wind	Z1		
Staythorpe C Stage 3					850							NGET	CCGT	Z10	Yes	Yes
Greater Gabbard					500							NGET	Offshore Wind	Z12	Yes	Yes
West Burton B Stage 1					435							NGET	CCGT	Z10	Yes	Yes
Staythorpe C Stage 1					425							NGET	CCGT	Z10	Yes	Yes
Severn Power Stage 1					425							NGET	CCGT	Z13	Yes	Yes
Staythorpe C Stage 2					425							NGET	CCGT	Z10	Yes	Yes
Thanet					300							NGET	Offshore Wind	Z15	Yes	Yes
Crystal Rig 2					200							SPT	Onshore Wind	Z6	Yes	Yes
Gordonbush Wind					70							SHETL	Onshore Wind	Z1	Yes	Yes
Lairg - Achany Wind Farm					50							SHETL	Onshore Wind	Z1	Yes	No
Edinbane Wind, Skye					42							SHETL	Onshore Wind	Z1	Yes	Yes
Fairburn Wind Farm					40							SHETL	Onshore Wind	Z1	Yes	No
Longpark					38							SPT	Onshore Wind	Z6	Yes	Yes
Toddleburn					36							SPT	Onshore Wind	Z6	Yes	Yes
Dun Law extension					30							SPT	Onshore Wind	Z6	Yes	Yes
Whitelee Stage 3					29							SPT	Onshore Wind	Z6	Yes	Yes
Kilbraur (Strath Brora) Wind Farm Stage 2					20							SHETL	Onshore Wind	Z1	Yes	Yes
Millenium Wind, Ceannacroc Stage 3					15							SHETL	Onshore Wind	Z1	Yes	Yes
Tullo Wind Farm, Laurencekirk					14							SHETL	Onshore Wind	Z2	Yes	Yes
Netherlands Interconnector Stage 1					0							NGET	Interconnector	Z15	Yes	Yes
Pembroke Stage 2						1200						NGET	CCGT	Z13	No	No
Grain Stage 2						860						NGET	CCGT	Z15	Yes	Yes
Pembroke Stage 1						800						NGET	CCGT	Z13	No	No
Netherlands Interconnector Stage 2						800						NGET	Interconnector	Z15	Yes	Yes
Clyde						519						SPT	Onshore Wind	Z6	Yes	Yes
West Burton B Stage 2						435						NGET	CCGT	Z10	Yes	Yes
West Burton B Stage 3						435						NGET	CCGT	Z10	Yes	Yes
Severn Power Stage 2						425						NGET	CCGT	Z13	Yes	Yes
Netherlands Interconnector Stage 3						400						NGET	Interconnector	Z15	Yes	Yes
Sheringham Shoal						315						NGET	Offshore Wind	Z12	Yes	No

Lincs Offshore Wind Farm						250						NGET	Offshore Wind	Z12	Yes	No
Griffin Windfarm						204						SHETL	Onshore Wind	Z3	Yes	No
Arecleoch						150						SPT	Onshore Wind	Z6	Yes	No
Heysham Offshore Wind Farm						140						NGET	Offshore Wind	Z9	Yes	No
Mark's Hill						99						SPT	Onshore Wind	Z6	Yes	No
Carraig Gheal (Fernoch)						60						SHETL	Onshore Wind	Z4	Yes	No
Rothes Biopower Plant						52						SPT	Biomass	Z5	No	No
Auchencorth						45						SPT	Onshore Wind	Z6	No	No
Andershaw						45						SPT	Onshore Wind	Z6	No	No
Beinn an Turic 2						38						SHETL	Onshore Wind	Z4	Yes	Yes
Drone Hill						38						SPT	Onshore Wind	Z6	Yes	No
Tormywheel						32						SPT	Onshore Wind	Z6	Yes	No
Barmoor						30						SPT	Onshore Wind	Z6	No	No
Kingsburn Wind farm, Fintry, Stirling						20						SPT	Onshore Wind	Z4	No	No
Drakelow D							1320					NGET	CCGT	Z11	Yes	No
Hatfield							800					NGET	IGCC with CCS	Z8	No	No
London Array Stage 1							630					NGET	Offshore Wind	Z15	No	No
Docking Shoal Wind Farm Ltd							500					NGET	Offshore Wind	Z12	No	No
East-West Interconnector 1							500					NGET	Interconnector	Z9	No	No
Partington Stage 1							430					NGET	CCGT	Z9	Yes	No
Grain Stage 3							430					NGET	CCGT	Z15	Yes	Yes
East-West Interconnector 2							375					NGET	Interconnector	Z9	No	No
Port Talbot							350					NGET	Woodchip	Z13	Yes	No
Kyle							300					SPT	Onshore Wind	Z6	No	No
Humber Gateway							300					NGET	Offshore Wind	Z8	No	No
Gwynt Y Mor Stage 1							294					NGET	Offshore Wind	Z9	No	No
Fallago							144					SPT	Onshore Wind	Z6	No	No
Harestanes							140					SPT	Onshore Wind	Z6	Yes	No
Earlshaugh							108					SPT	Onshore Wind	Z6	No	No
Waterhead Moor							72					SPT	Onshore Wind	Z6	No	No
Dersalloch							69					SPT	Onshore Wind	Z6	No	No
Ewe Hill							66					SPT	Onshore Wind	Z6	No	No
Newfield							60					SPT	Onshore Wind	Z6	No	No
Harrows Law							55					SPT	Onshore Wind	Z6	No	No
Ballindalloch Muir Wind Farm, Balfron							21					SPT	Onshore Wind	Z3	No	No
Causeymire Phase 2							7					SHETL	Onshore Wind	Z1	Yes	No
Brine Field								1020				NGET	CCGT	Z7	Yes	No
Partington Stage 2								430				NGET	CCGT	Z9	Yes	No

Pen Y Comoedd								299				NGET	Onshore Wind	Z13	No	No
Tees Renewable Energy Plant								299				NGET	Biomass	Z7	No	No
Gwynt Y Mor Stage 2								294				NGET	Offshore Wind	Z9	No	No
Amlwch								270				NGET	CCGT	Z9	No	No
Portbury								150				NGET	Biomass	Z13	No	No
Neilston								100				SPT	Onshore Wind	Z6	No	No
HearthStanes B Windfarm								81				SPT	Onshore Wind	Z6	No	No
Afton								77				SPT	Onshore Wind	Z6	No	No
Ulzieside								69				SPT	Onshore Wind	Z6	No	No
Pencloe								63				SPT	Onshore Wind	Z6	No	No
Brockloch Rig								60				SPT	Onshore Wind	Z6	Yes	No
Whiteside Hill								27				SPT	Onshore Wind	Z6	Yes	No
Sutton Bridge B									1305			NGET	CCGT	Z12	No	No
Race Bank Wind Farm									500			NGET	Offshore Wind	Z12	No	No
Barking C									470			NGET	CCGT	Z14	Yes	No
Strathy North & South Wind									226			SHETL	Onshore Wind	Z1	No	No
Gwynt Y Mor Stage 3									147			NGET	Offshore Wind	Z9	No	No
Pairc (South Lochs) Wind, Lewis									94			SHETL	Onshore Wind	Z1	No	No
Berry Burn Windfarm									82			SHETL	Onshore Wind	Z1	No	No
Mid Hill Wind, Stonehaven									75			SHETL	Onshore Wind	Z2	No	No
Blackcraig									71			SPT	Onshore Wind	Z5	No	No
Margree									70			SPT	Onshore Wind	Z6	No	No
Shira									52			SHETL	Onshore Wind	Z4	No	No
Glendoe, Fort Augustus Stage 2									48			SHETL	Hydro	Z1	Yes	Yes
Stacain Wind Farm, Sron Mor, Inveraray									42			SHETL	Onshore Wind	Z4	No	No
Black Craig 40MW Windfarm, Dunoon									40			SHETL	Onshore Wind	Z3	No	No
Tomatin Windfarm									30			SHETL	Onshore Wind	Z1	No	No
Carscreugh, Dumfries & Galloway									21			SPT	Onshore Wind	Z6	No	No
Blyth										1600		NGET	IGCC with CCS	Z7	No	No
Bristol Channel Offshore Windfarm										1512		NGET	Offshore Wind	Z17	No	No
Teesport										925		NGET	IGCC with CCS	Z7	No	No
Baglan Bay 2 Stage 1										435		NGET	CCGT	Z13	No	No
London Array Stage 2										370		NGET	Offshore Wind	Z15	No	No

Eishken Estate, Isle of Lewis										300		SHETL	Onshore Wind	Z1	No	No
North Nesting Wind, Shetland										250		SHETL	Onshore Wind	Z1	No	No
Clashindarroch Wind, Huntly										113		SHETL	Onshore Wind	Z2	No	No
Black Craig 90MW, Dunoon										90		SHETL	Onshore Wind	Z4	No	No
Camster										62		SHETL	Onshore Wind	Z1	No	No
Calliachar Wind Farm, Aberfeldy										62		SHETL	Onshore Wind	Z3	No	No
Aultmore Windfarm										60		SHETL	Onshore Wind	Z1	No	No
Baillie & Bardnaheigh Wind										57		SHETL	Onshore Wind	Z1	No	No
Dunbeath Wind Farm										55		SHETL	Onshore Wind	Z1	No	No
Montreathmont Moor Wind, Angus										40		SHETL	Onshore Wind	Z2	No	No
Novar 2 Wind Farm, Alness										32		SHETL	Onshore Wind	Z2	Yes	No
Stroupster Wind Farm, near Wick, Caithness										32		SHETL	Onshore Wind	Z1	No	No
Fasnakyle Compensation Hydro (Unit 4)										8		SHETL	Hydro	Z1	Yes	Yes
Mid Wales West											408	NGET	Onshore Wind	Z9	No	No
Carnedd Wen											191	NGET	Onshore Wind	Z9	No	No
Llanbrynmair South											110	NGET	Onshore Wind	Z9	No	No
Careston Wind Farm, Brechin, Angus											32	SHETL	Onshore Wind	Z2	No	No
	415	79	348	2783	3952	7392	6971	3239	3274	6002	741					
	415	494	842	3625	7577	14969	21941	25180	28454	34456	35197					

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Table 3.8 - Overview of Capacity Changes from 2005/06 to 2015/16

Category	Description	Biopower	CCGT	CHP	Coal + AGT	Hydro	Interconnector	Wind	Total
1	Existing by 2008/09 Winter Peak	45	1865	601	0	52	0	1072	3635
2	Under Construction	0	5145	0	0	56	1200	1849	8250
3	Sub-Total (Lines 1 & 2)	45	7010	601	0	108	1200	2922	11885
4	Plant with Section 36 Consent and (where relevant) Section 14 Consent	350	3670	0	0	0	0	1644	5664
5	Sub-Total (Lines 1 & 2 & 4)	395	10680	601	0	108	1200	4566	17549
6	Plant without Section 36 Consent and (where relevant) Section 14 Consent	501	4010	0	3325	0	875	8937	17648
7	Total (Lines 1 & 2 & 4 & 6)	896	14690	601	3325	108	2075	13503	35197

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Table 3.9 - Additional Transmission Contracted Generation Capacity since 31 December 2007

Licensee	Station Name	Capacity (MW)	Year	Company	Plant Type
NGET	Tees Renewable Energy Plant	299	2012	MGT Renewable Energy Ltd	Biomass
NGET	Portbury	150	2012	E.ON Climate & Renewables UK Operations Ltd	Biomass
NGET	Barking C	470	2013	Barking Power Ltd	CCGT
NGET	Partington Stage 1	430	2011	Bridestones Developments Ltd	CCGT
NGET	Partington Stage 2	430	2011	Bridestones Developments Ltd	CCGT
NGET	East-West Inerconnector 2	375	2011	East West Cable One Ltd	Interconnector
NGET	Carnedd Wen	191	2015	Npower Renewables Ltd	Onshore Wind
NGET	Llanbrynmair South	110	2015	Renewable Energy Systems UK Ltd	Onshore Wind
NGET	Mid Wales West	408	2015	SP Manweb	Onshore Wind

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Table 3.10 - Generation Disconnections since 2005/06

Licensee	Closure Year	Station Name	Set(s) Disconnected	Capacity (MW)	Plant Type	Owner	Commissioning Year
SPT	2005	Chapelcross	1-8	150	Nuclear Magnox	BNFL (Magnox Electric)	
NGET	2007	Dungeness A	1-4	440	Nuclear Magnox	Magnox Electric plc	1965
NGET	2007	Sizewell A	1, 2	458	Nuclear Magnox	Magnox Electric plc	1966
NGET	2011	Oldbury	1, 2	470	Nuclear Magnox	Magnox Electric plc	1967-68
NGET	2011	Wylfa	1, 2, 3, 4	1006	Nuclear Magnox	Magnox Electric plc	1971
			Total	2524			

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Table 3.11 - Unavailable Generating Units

Licensee	Year	Station Name	Unit(s)	Capacity (MW)	Owner	Plant Type	SYS Study Zone
NGET	1991	Cottam	G2, G4	50	EDF Energy	OCGT	Z10
NGET	1991	Ferrybridge C	G6, G7	34	Keadby Generation Ltd	OCGT	Z8
NGET	1991	Fiddlers Ferry	G1, G4	34	Keadby Generation Ltd	OCGT	Z9
NGET	1991	Kingsnorth	G2A, G3A	44	EON UK plc	OCGT	Z15
NGET	1991	Ratcliffe on Soar	G1, G3	34	PowerGen	OCGT	Z11
NGET	1994	Cottam	G1, G3	50	EDF Energy	OCGT	Z10
NGET	1994	Drax	G7	25	Drax Power Ltd	OCGT	Z8
NGET	1994	Eggborough	G6, G7	34	Eggborough Power Ltd	OCGT	Z8
NGET	1994	Fawley	1	500	RWE Npower plc	Oil	Z16
NGET	1994	Grain	2	675	EON UK plc	Oil	Z15
NGET	1994	Grain	G2A, G3A, G5A	87	EON UK plc	OCGT	Z15
NGET	1994	Ironbridge B	G1, G2	34	EON UK plc	OCGT	Z11
NGET	1994	Tilbury B	G7A	17	RWE Npower plc	OCGT	Z15
NGET	1994	West Burton	G2, G3	40	London Electricity	OCGT	Z10
NGET	1995	Fawley	G2, G4	34	RWE Npower plc	OCGT	Z16
NGET	1995	Littlebrook D	3	685	Innogy	Oil	Z14
NGET	1998	Grain	3	675	EON UK plc	Oil	Z15
NGET	1998	Tilbury B	G10A	17	RWE Npower plc	OCGT	Z15
NGET	1998	Tilbury B	7	350	RWE Npower plc	Medium Unit Coal	Z15
NGET	2002	Killingholme 1	2S	150	EON UK plc	CCGT	Z8
NGET	2003	Killingholme 1	1S	150	EON UK plc	CCGT	Z8
NGET	2004	Killingholme 1	1A, 1B, 2A, 2B	600	EON UK plc	CCGT	Z8
NGET	2006	Killingholme 1	1A, 1B, 1S, 2A, 2B, 2S	-900	EON UK plc	CCGT	Z8
NGET	2006	Fawley	1	-500	RWE Npower plc	Oil	Z16
			Total	2919			

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Table 3.12 - Nominal Interconnection Import and Export Capabilities (MW)

Licensee	Name	Normal Direction of Flow	Import Capability	Export Capability	Commissioning Year
NGET	French Link	Import	1988	2000	Existing
NGET	Netherlands Interconnector	Import	1320	1390	2010
NGET	Republic of Ireland 1	Export	500	500	2011
NGET	Republic of Ireland 2	Export	375	375	2011
SPT	Northern Ireland	Export	80	500	Existing

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Table 3.13 - Growth in Generation Capacity (MW) by Plant Type and SYS Study Zone, 2009/10 to 2015/16

Plant Type	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	Z11	Z12	Z13	Z14	Z15	Z16	Z17	Total
Biomass					52		299						150					501
CCGT							1020		1130	870	1320	1305	2860	470	1290			10265
CHP																		
Hydro	56																	56
IGCC with CCS							2525	800										3325
Interconnector									875						1200			2075
Large Unit Coal																		
Large Unit Coal + AGT																		
Medium Unit Coal																		
Medium Unit Coal + AGT																		
Nuclear AGR																		
Nuclear Magnox									-980				-470					-1450
Nuclear PWR																		
OCGT																		
Offshore Wind								300	875			1565			1000		1512	5252
Oil + AGT																		
Onshore Wind	1255	291	327	302	71	2541			709				299					5796
Pumped Storage																		
Small Unit Coal																		
Woodchip													350					350
Total	1311	291	327	302	123	2541	3844	1100	2609	870	1320	2870	3189	470	3490	0	1512	26170

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Table 3.14 - Subtotals of TEC (MW) by Plant Type and SYS Study Zone, 2009/10

Plant Type	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	Z11	Z12	Z13	Z14	Z15	Z16	Z17	Total
Biomass						45												45
CCGT		1524					1935	4945	2924	3410		3031	4006	2123	2305	1320	905	28428
CHP		12			123	120		1320	365		228					158		2326
Hydro	466	18	321	232		33												1070
IGCC with CCS																		0
Interconnector						80									1988			2068
Large Unit Coal					2304								2109					4413
Large Unit Coal + AGT								7832	1987	3987	4003		1692		1966			21467
Medium Unit Coal						1102												1102
Medium Unit Coal + AGT															1131			1131
Nuclear AGR						2289	1207		2406						1081		1261	8244
Nuclear Magnox									980				470					1450
Nuclear PWR												1200						1200
OCGT	10												100	144		195	140	589
Offshore Wind												500			300			800
Oil + AGT														1245	1355	1036		3636
Onshore Wind	684	71	74	208	35	1056												2128
Pumped Storage	300		440						2004									2744
Small Unit Coal							420						363					783
Woodchip																		
Total	1460	1625	834	440	2462	4725	3562	14097	10666	7397	4231	4731	8740	3512	10126	2709	2306	83624

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Table 3.15 - Subtotals of TEC (MW) by Plant Type and SYS Study Zone, 2015/16

Plant Type	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	Z11	Z12	Z13	Z14	Z15	Z16	Z17	Total
Biomass	0	0	0	0	52	45	299	0	0	0	0	0	150	0	0	0	0	546
CCGT	0	1524	0	0	0	0	2955	4945	4054	4280	1320	4336	6866	2593	3595	1320	905	38693
CHP	0	12	0	0	123	120	0	1320	365	0	228	0	0	0	0	158	0	2326
Hydro	522	18	321	232	0	33	0	0	0	0	0	0	0	0	0	0	0	1126
IGCC with CCS	0	0	0	0	0	0	2525	800	0	0	0	0	0	0	0	0	0	3325
Interconnector	0	0	0	0	0	80	0	0	875	0	0	0	0	0	3188	0	0	4143
Large Unit Coal	0	0	0	0	2304	0	0	0	0	0	0	0	2109	0	0	0	0	4413
Large Unit Coal + AGT	0	0	0	0	0	0	0	7832	1987	3987	4003	0	1692	0	1966	0	0	21467
Medium Unit Coal	0	0	0	0	0	1102	0	0	0	0	0	0	0	0	0	0	0	1102
Medium Unit Coal + AGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1131	0	0	1131
Nuclear AGR	0	0	0	0	0	2289	1207	0	2406	0	0	0	0	0	1081	0	1261	8244
Nuclear Magnox	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear PWR	0	0	0	0	0	0	0	0	0	0	0	1200	0	0	0	0	0	1200
OCGT	10	0	0	0	0	0	0	0	0	0	0	0	100	144	0	195	140	589
Offshore Wind	0	0	0	0	0	0	0	300	875	0	0	2065	0	0	1300	0	1512	6052
Oil + AGT	0	0	0	0	0	0	0	0	0	0	0	0	0	1245	1355	1036	0	3636
Onshore Wind	1940	362	401	490	106	3596	0	0	709	0	0	0	299	0	0	0	0	7904
Pumped Storage	300	0	440	0	0	0	0	0	2004	0	0	0	0	0	0	0	0	2744
Small Unit Coal	0	0	0	0	0	0	420	0	0	0	0	0	363	0	0	0	0	783
Woodchip	0	0	0	0	0	0	0	0	0	0	0	0	350	0	0	0	0	350
Total	2771	1916	1161	722	2585	7265	7406	15197	13275	8267	5551	7601	11929	3982	13616	2709	3818	109773

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Table 3.16 - Transmission Contracted Generation beyond 2015/16

Licensee	Project Name	Capacity (MW)	Registered Company Name	Plant Type	Year
NGET	Kings Lynn B	981	Centrica KL Ltd	CCGT	2016
NGET	Baglan Bay 2 Stage 2	435	Abernedd Power Company Ltd	CCGT	2016
NGET	Damhead Creek 2 Stage 1	493	ScottishPower (DCL) Ltd	CCGT	2019
NGET	Damhead Creek 2 Stage 2	493	ScottishPower (DCL) Ltd	CCGT	2022
NGET	South Holland	840	InterGen (UK) Ltd	CCGT	2022
NGET	Huntspill	850	Huntspill Power Company Ltd	CCGT	2023
NGET	Thames Haven	840	InterGen (UK) Ltd	CCGT	2023
NGET	Tilbury Stage 2	369	RWE Npower plc	Medium Unit Coal + AGT	2016
NGET	Wylfa C Stage 1	1200	RWE Npower plc	Nuclear APR	2020
NGET	Wylfa C Stage 2	1200	RWE Npower plc	Nuclear APR	2021
NGET	Wylfa C Stage 3	1200	RWE Npower plc	Nuclear APR	2022
NGET	Bradwell B	1650	British Energy Generation Ltd	Nuclear EPR	2016
NGET	Sizewell C Stage 1	1650	British Energy Generation Ltd	Nuclear EPR	2016
NGET	Dungeness C	1650	British Energy Generation Ltd	Nuclear EPR	2016
NGET	Hinkley Point C	3300	British Energy Generation Ltd	Nuclear EPR	2016
NGET	Wylfa B	1670	EDF Development Company Ltd	Nuclear EPR	2017
NGET	Hinkley Point West	1600	EDF Development Company Ltd	Nuclear EPR	2020
NGET	Oldbury-on-Severn	1600	E.ON UK plc	Nuclear EPR	2020
NGET	Sizewell C Stage 2	1650	British Energy Generation Ltd	Nuclear EPR	2021
NGET	Huntspill	100	Huntspill Power Company Ltd	OCGT	2023
SHETL	Glenmoriston Hydro Group (Additional Capacity)	6	SSE Generation Limited	Hydro	
SHETL	Beatrice Offshore Wind Farm, Dunbeath	1000	SSE Generation Limited	Offshore Wind	

SHETL	Cairn Duhie Wind Farm, Ferness, Nairn	34	Renewable Energy Systems UK Ltd	Onshore Wind	
SHETL	Cairn Uish phase 2	40	Fred Olsen Wind 1 Limited	Onshore Wind	
SHETL	Viking Energy, Shetland	300	Viking Energy, Ltd	Onshore Wind	
SHETL	Dumnaglass Wind Farm, Stratherrick, Inverness	108	Renewable Energy Systems UK Ltd	Onshore Wind	
SHETL	Pentland Road Wind, Lewis	13	Farm Energy Ltd	Onshore Wind	
SHETL	Hanna Windfarm	81	Wind Energy (Hanna) Limited	Onshore Wind	
SHETL	Loch Luichart Wind, Conon Valley	66	Infinergy Ltd	Onshore Wind	
SHETL	Invercassley Windfarm, Lairg	50	Airtricity Developments (Scotland) Ltd	Onshore Wind	
SHETL	Spittal Hill Windfarm, Nr Mybster, Caithness	80	Spittal Hill Wind Farm Limited	Onshore Wind	
SHETL	Forse 60MW Windfarm	60	Wind Energy (Forse) Limited	Onshore Wind	
SHETL	Drummuir Wind, Keith	48	Renewable Energy Systems UK Ltd	Onshore Wind	
SHETL	Tomatin Wind Farm (Additional Capacity)	69	Eurus Energy UK Limited	Onshore Wind	
SHETL	Tom Nan Clach Windfarm, Cawdor, Inverness	150	Infinergy Ltd	Onshore Wind	
SHETL	Tofingall Wind Farm, Mybster, Caithness	50	Gamesa Energy UK Ltd	Onshore Wind	
SHETL	Rosehall, Shin	28	E.ON UK Renewables Ltd	Onshore Wind	
SHETL	Braemore Windfarm, Shin	66	Wind Prospect Developments Limited	Onshore Wind	
SHETL	Jacksbank Windfarm, Glenbervie	81	Ron Shanks Development Project Limited	Onshore Wind	
SHETL	Glen Calvie Wind Farm, Ardgay	69	Wind Energy (Glencalvie) Limited	Onshore Wind	
SHETL	Glen Calvie B Wind Farm, Ardgay	45	Wind Energy (Glencalvie) Limited	Onshore Wind	
SHETL	Dorenell Wind Farm (Scaul Hill)	180	Infinergy Ltd	Onshore Wind	
SHETL	Aberchalder Cluster Wind farms, Ft Augustus	300	Gamesa Energy UK Ltd	Onshore Wind	
SHETL	A'Chruach	50	Novera Energy plc	Onshore Wind	
SHETL	Corriemoillie Windfarm, Dingwall	22	E.ON UK plc	Onshore Wind	
SHETL	Cambusmore Windfarm	41	Renewable Energy Systems UK Ltd	Onshore Wind	
SHETL	Kilchattan Wind Farm, Campbeltown, Kintyre	10	Wind Prospect Developments Ltd	Onshore Wind	

SHETL	Stromness Wave Farm, Orkney	22	CRE Energy Ltd	Wave	
SPT	Chapelcross Biopower CHP Plant	250	Scottish Biopower Ltd	Biopower CHP	
SPT	Killoch Biopower CHP Plant	250	Scottish Biopower Ltd	Biopower CHP	
SPT	Blacklaw Extension	69	CRE Energy Ltd	Onshore Wind	