National Electricity Transmission System Seven Year Statement

May 2010

Chapters

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NATIONAL ELECTRICITY TRANSMISSION SYSTEM
SEVEN YEAR STATEMENT
MAY 2010

National Grid

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FOREWORD

National Grid Electricity Transmission plc, acting in its role as National Electricity Transmission System Operator (NETSO), is pleased to present this 2010 NETS Seven Year Statement (NETS SYS), which covers the years 2010/11 to 2016/17 inclusive.

This is the sixth NETS 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 NETSO, became required to produce a single Seven Year Statement covering the whole of the national electricity transmission system (i.e. the NETS SYS) on an annual basis. The two Scottish transmission licensees are required to assist National Grid in preparing each NETS SYS pursuant to their licence obligations.

The form of this 2010 NETS SYS has been approved by the Authority and its main purpose is to assist existing and prospective new users of the national electricity transmission system in assessing opportunities available to them for making new or additional use of the national electricity transmission system in the competitive electricity market.

It can be seen from the document that opportunities for making new or additional use of the National Electricity transmission system is based on both technical and commercial factors. An overview of some of the key commercial factors associated with access to the national electricity transmission system is contained in the document; however, we recommend prospective users of the system to contact National Grid directly if they want to fully understand the opportunities available to them.

The subject matter of this 2010 NETS 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 NETS SYS contains a wide range of technical and non-technical information relating to the national electricity transmission system.

I hope you find our 2010 NETS SYS both interesting and informative. Given the challenges facing the electricity industry over the coming seven 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 2011 NETS SYS. An electronic questionnaire is available on our website for this purpose:

http://www.zoomerang.com/Survey/WEB22AQ28NGKL3

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 2010

NETS Seven Year Statement
May 2010

Executive Summary

Introduction

This 2010 National Electricity Transmission System Seven Year Statement (NETS SYS) is the sixth 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 National Electricity Transmission System Operator (NETSO, formerly GBSO), is required to produce a single NETS 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 2010 NETS SYS presents a wide range of information relating to the transmission system in Great Britain including demand, generation, plant margins, characteristics of the existing and planned national electricity transmission system, its expected performance and capability and other related information. Amongst other uses, this information is intended to assist existing and prospective new Users of the national electricity transmission system in assessing opportunities available to them for making new or further use of the national electricity 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” (Chapter 10), which provides a high level overview of BETTA and also reports on related issues such as governance, institutional and contractual arrangements, and provides a link to the new Offshore Development Information Statement (ODIS).

It should be noted that the generation background, on which this document is based, is not National Grid’s forecast of the most likely developments over the next seven years (due to commercial confidentiality we are unable to show this level of detail on future generation project developments). The generation background is a 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 the number of generation projects opening or closing.

On the other hand, the main demand forecasts included in this document are National Grid’s own forecasts. Demand forecasts received from customers are also included for comparison purposes.

The data and results presented in this summary are correct as at 31 December 2009 (the data freeze date) and do not include changes in the contracted position since that date. Any subsequent changes to the contracted background will be published in the NETS SYS Updates.

The NETS SYS updates have now been included within the Transmission Networks Quarterly Connections Update, which is published at the following location:

http://www.nationalgrid.com/uk/Electricity/GettingConnected/gb_agreements/

The latest update was issued in April 2010, and includes contractual 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 national electricity transmission system presented in this Statement are National Grid's own forecasts. These (NGET) forecasts are national projections for Great Britain. For comparison purposes, forecasts based on information submitted by Customers who take (or propose to take) electricity from the system are also presented. These 'User' based forecasts are based on the demands at individual Grid Supply Point demands.

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 national electricity 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.

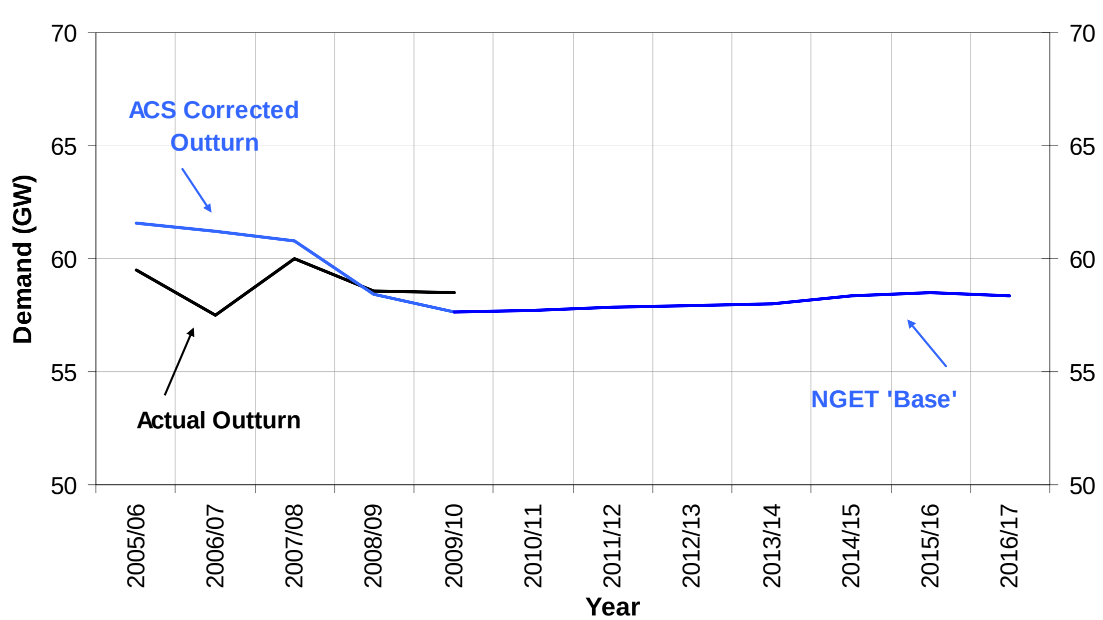
Outturn Peak Demand

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 2009/10 to ACS conditions yields a provisional 'unrestricted' peak of 58.2GW; a decline of 0.8GW 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 demand also includes a 100MW assumed interconnector export at peak to Northern Ireland.

Figure ES.1 includes recent outturns together with the current NGET 'Base' forecasts of ACS peak demand on the GB transmission system. Please note that the demands in Figure ES.1 are exclusive of station demand (0.6GW).

Figure ES.1 - Historical Outturn & NGET's 'Base' Peak Demand Forecast



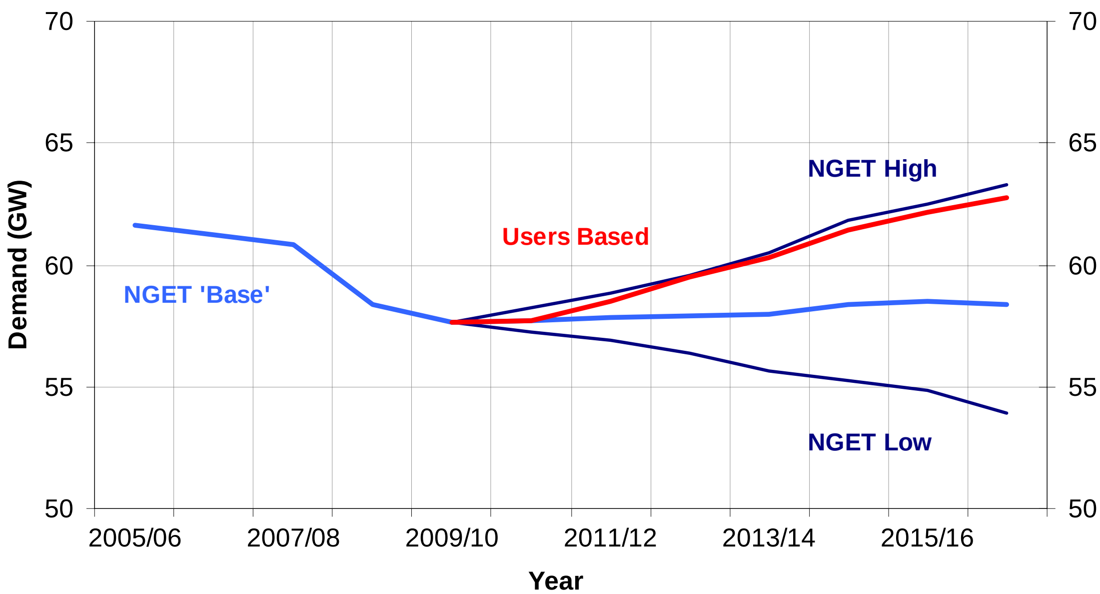
National Grid View of Demand Growth

As well as our own 'Base' forecast of peak demand and annual electricity requirements, we have also prepared '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 and fuel prices, result in a fairly wide range of outcomes for transmission system demand.

Figure ES.2 compares our Base, High and Low demand forecasts with the User based forecasts. Under the 'Base' forecast the ACS 'unrestricted' peak demand shows slow average growth of 0.2% per annum from 57.6GW in 2009/10 to 58.4GW in 2016/17. Please note that the demands in Figure ES.2 are exclusive of station demand (0.6GW).

Figure ES.2 also includes actual and weather-corrected recent outturns of peak demand.

Figure ES.2 - Comparison of Users-Based Forecast and NGET's Projections



User Based Forecasts

Figure ES.2 also shows peak unrestricted demand on the national electricity transmission system in ACS (average cold spell) conditions, as projected by the system 'Users', which increases from the provisionally estimated outturn of 57.6GW in 2009/10 to 62.8GW by 2016/17. This represents an average growth rate of 1.2% per annum over the period as indicated in Figure ES.2.

Throughout the period covered by this year's forecast, the User based forecast is more optimistic than NGET's 'Base' forecast and is almost as high for all years as NGET'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 2008/09. The NGET forecasts benefit from being based on demand seen in 2009/10, 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 that are used to meet the ACS Peak Demand. Accordingly, this chapter reports on all power stations directly connected to the national electricity 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.

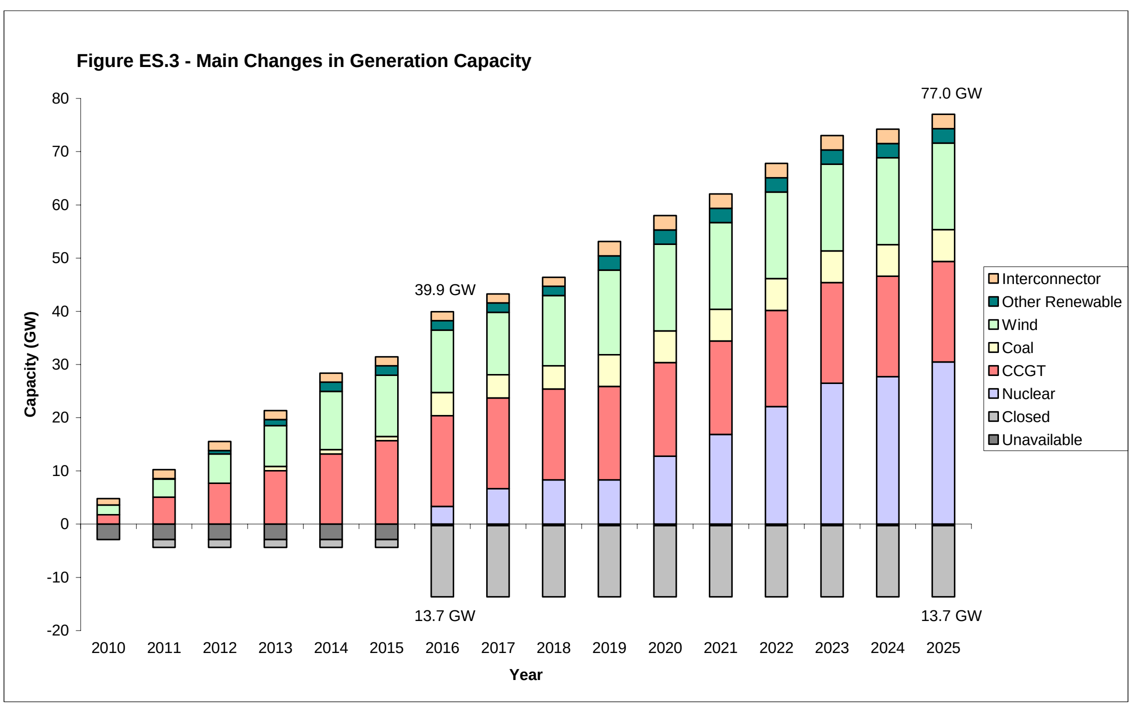


Figure ES.3 illustrates the reported increase in generation capacity from 2009/10 onwards. Notified reductions in capacity from plant closures and from plant being placed in reserve have been taken into account. The capacity of stations that will close on or before 31st December 2015 due to opting out of the LCPD amounts to 12GW of coal and oil capacity. These stations have been retained in the generation background up to and including 2015/16 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 affected stations have however, been shown as closed from 2016/17 onwards, and this accounts for the step change in closed capacity in 2016 shown in Figure ES.3.

Figure ES.3 shows that over the seven years of this statement, from 2010/11 to 2016/17, there is a reported rise in new capacity of 39.9GW. Featuring in this increase are 17.1GW of CCGT, 11.7GW of wind, 4.4GW of new coal capacity, 1.7GW of other renewables (mainly biomass and biopower) and 1.7GW of interconnectors.

Although outside the scope of this statement, the level of contracted activity beyond 2016/17 is also depicted in Figure ES.3. Figure ES.3 shows that up to and including the year 2025, there is a reported increase in new capacity of 77.0GW. The effect of the proposed new nuclear generation can be seen in the later years, and accounts for 30.5GW of this total. The remainder is made up from 18.9GW of CCGT, 16.3GW of wind, 6.0GW of new coal capacity, 2.7GW of interconnectors and 2.7GW of other renewables (mainly biomass and biopower, but with some tidal and wave).

Further details of individual projects can be found in the Transmission Networks Quarterly Connections Update:

http://www.nationalgrid.com/uk/Electricity/GettingConnected/gb_agreements/

It is worth remembering, however, that, in the event, there may well be a more graded increase in activity over the years, than that shown in Figure ES.3. 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 ES.4 - Installed Capacity and Peak Demand

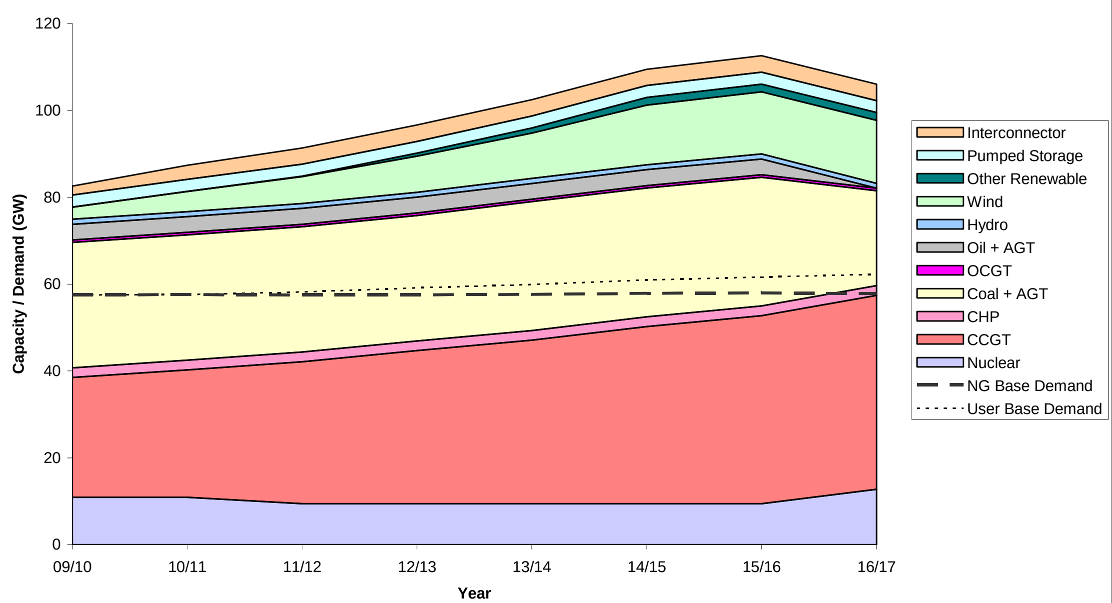


Figure ES.4 illustrates the main plant types of the contracted generation background over the period from 2009/10 to 2016/17 and includes both existing and proposed new transmission contracted generation. The aggregate power station capacity (TEC and/or 'Size of Power Station') is reported to rise from 82.6GW in 2009/10 to 109.1GW by 2016/17. This represents an overall increase of 26.6GW, or 30.4% of the 2009/10 total, over the period from the 2009/10 winter peak to the 2016/17 winter peak. This net increase is made of the following:

- an increase of 17.1GW (+19.5%) in CCGT capacity;
- an increase of 11.7GW (+13.4%) in wind capacity;
- a net increase of 1.85GW (+2.1%) in nuclear capacity;
- an increase of 1.7GW (+2.0%) in other renewables capacity (mainly biomass, biopower and woodchip generation) (shown collectively as biopwer in Figure ES.4);
- an increase of 1.7GW (+1.9%) in new import capability (+1.9%);
- a decrease of 3.6GW (-4.2%) in oil capacity (-4.2%);
- a net decrease of 3.9GW (-4.5%) in coal capacity.

The largest change is due to the 17.1GW increase in CCGT plant capacity over the period. On this basis, the CCGT plant has the potential to overtake coal as the predominant plant type in capacity terms. By 2016/17, CCGT capacity is reported to exceed coal capacity by 19.7GW and account for 40.1% of the total transmission contracted installed generation capacity. Please note that this growth in CCGTs of 17.1GW excludes those stations under construction that are contracted to connect in 2009/10, e.g. Severn Power Stage 1 and Staythorpe Stages 1, 2 & 3, amounting to a total of 1.7GW. In addition there are a number of other CCGTs under construction e.g. Severn Power Stage 2, Staythorpe Stage 4, West Burton Stages 1, 2 & 3 and Grain Stages 2 & 3, which amount to 3.4GW and are included in the 17.1GW figure.

The second largest reported increase is due to the growth in Wind generation, with onshore wind accounting for a 5.3GW increase and offshore wind accounting for a 6.4GW increase in overall capacity. Wind generation capacity (both onshore and offshore) is reported to rise to 14.5GW by 2016/17. Currently around 1.8GW of wind is under construction with 0.8GW due to connect in 2009/10 and 1GW contributing to the 11.7GW reported growth over 2009/10 to 2016/17.

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 Chapter 4 (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). Figure ES.5 summarises the data presented in Chapter 4 in terms of the main plant and fuel types.

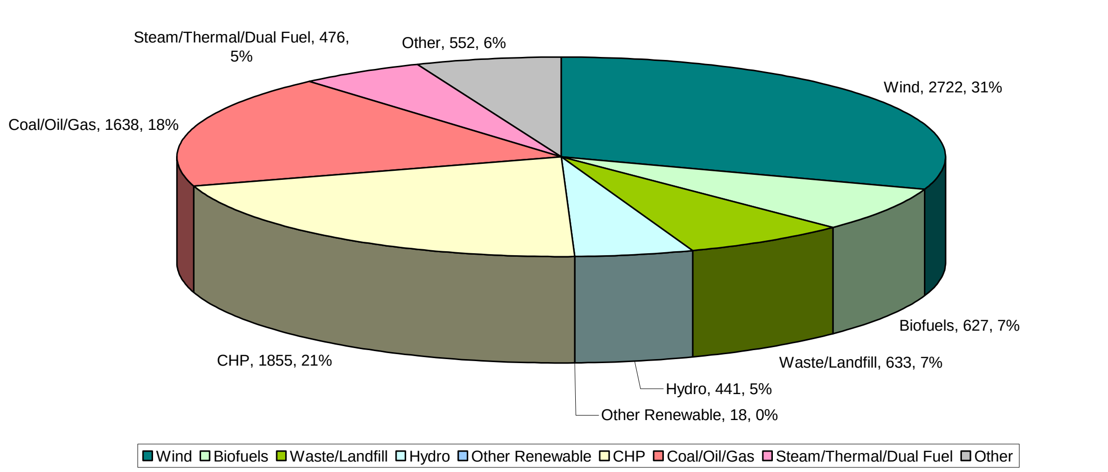


Figure ES.5 - Main Types of Embedded Generation (MW)

In Figure ES.4, the 2.7GW of wind capacity consists of 1.8GW of onshore wind and 0.9GW of offshore wind capacity. The 2.7GW of wind capacity shown in Figure ES.5 is in addition to the installed wind capacity reported under "Generation". Please note that the output of embedded wind generation 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.

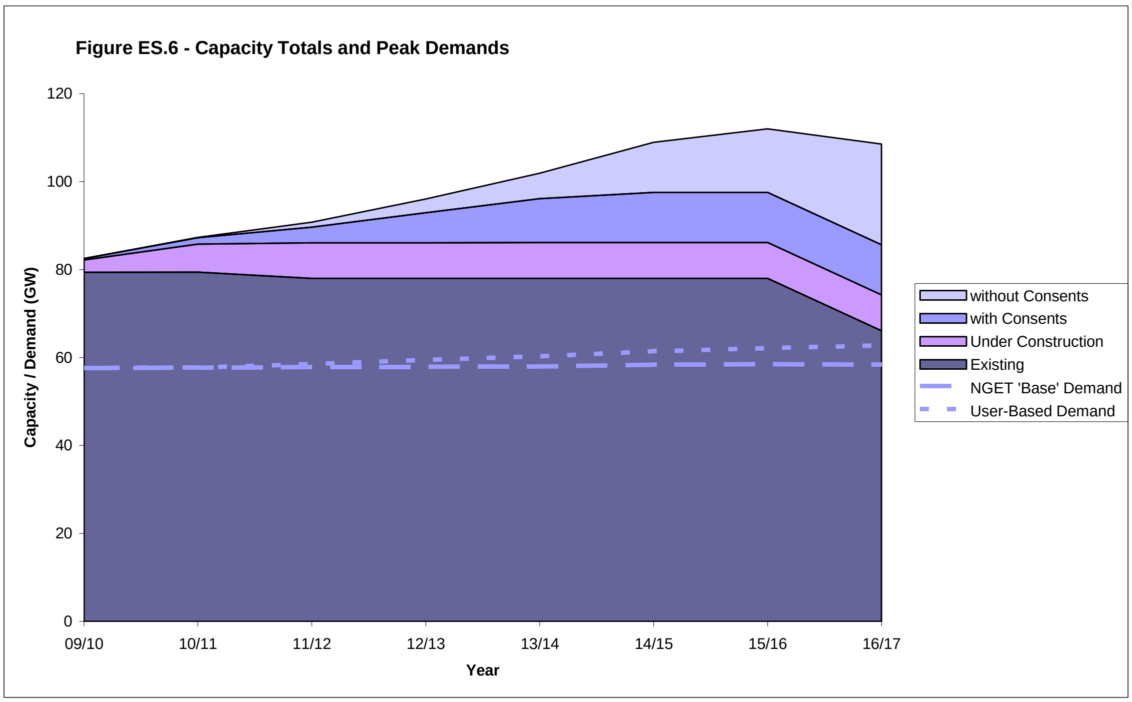
National Grid's responsibility in the Balancing Mechanism is to balance generation and demand and to resolve transmission constraints. The intermittent effect of wind (i.e. its output is naturally subject to fluctuation and unpredictability relative to the more traditional generation technologies) coupled 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.

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, most notably the potential impact of both the interim and enduring connect and manage regimes.

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 national electricity 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, as shown graphically in Figure ES.6.



In view of these uncertainties relating to the future generation position, four different generation backgrounds have been considered in Figure ES.6. 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.

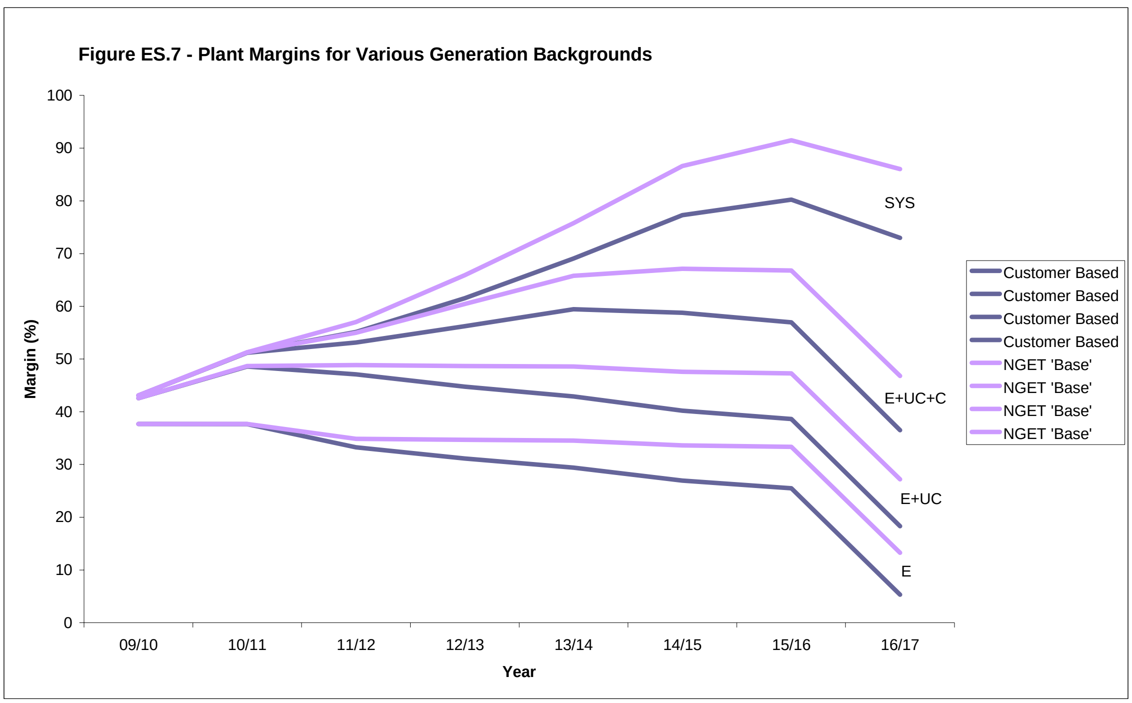
- Background 1: ‘Existing Background’ (E)
  This background includes all transmission contracted generation plant that is already constructed and connected to either the transmission network or a distribution network

- Background 2: ‘Existing or Under Construction Background’ (E+UC)
  This background includes all the generation included under background 1, plus all future generation plant under construction.

- Background 3: ‘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 (where applicable) Section 14 (S14) of the Energy Act 1976 (see Chapter 10: "Market Overview"). 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 4: ‘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.

Figure ES.7 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 four backgrounds; giving eight sensitivities in all.

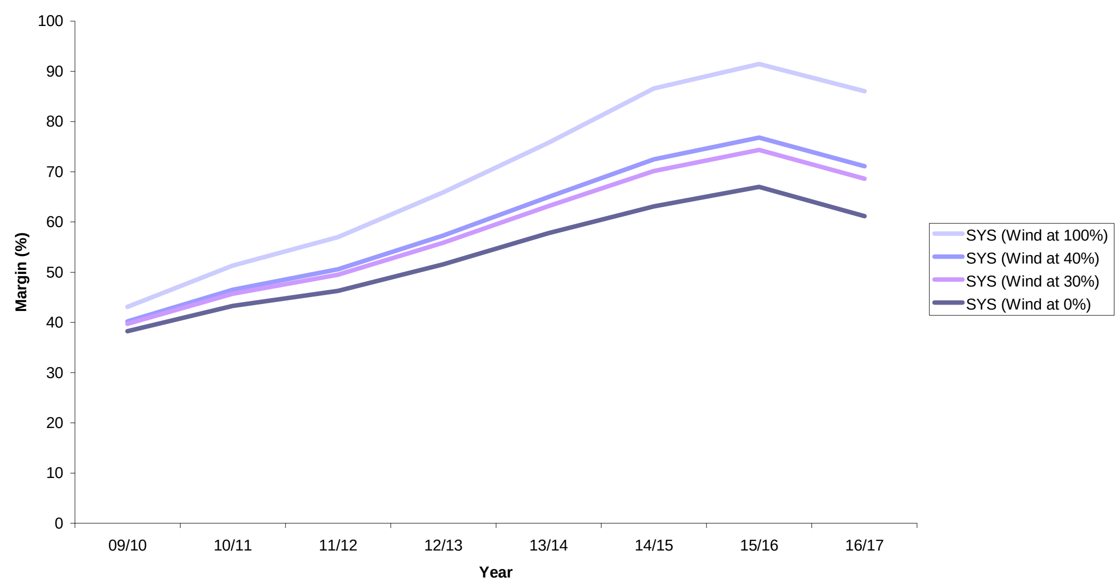


The main text considers a number of other factors, which can influence the value of plant margin. These include: as yet un-notified future generation disconnections (e.g. LCPD closures); the possible return to service of previously decommissioned plant (or the return to service of plant with TEC currently 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 ES.8 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.

To include the effect of wind availability in the final year margins in Figure ES.7 (i.e. 2016/17), we would consider the “Existing & Under Construction” (E+UC) Background, which is the second lowest scenario in Figure ES.7. The margins in 2016/17 for this background are 18% based on the customer based demand forecast, and 27% based on the NGET demand forecast. If we then incorporate wind at zero capacity, then these plant margins would fall from 18% to 13% and 27% to 22% 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. This is based on a plant margin of 20% being an acceptable minimum for long-term planning purposes.

Figure ES.8 - Plant Margins for various Wind Generation Availability Assumptions (relative to SYS Background)



The margins displayed in Figure ES.7 and Figure ES.8 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. 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 'Generation Ranking Order', which is explained in Chapter 7 ("Transmission System Performance"), is used to determine which generation is operated for the study purposes of this Statement.

There are a number of boundaries on the national electricity 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 Study 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 7.2 in Chapter 7 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 Chapter 8: "Transmission System Capability") includes probabilistic transfers for all 17 boundaries. As an example, the results for two key boundaries are given in Figure ES.9 and Figure ES.10. With the predominant high north to south power flows seen on our system, these two boundaries (i.e. the SPT to NGET boundary and Midlands to South boundary) are particularly important.

Figure ES.9 - Boundary Transfers and Capability (Boundary B6: SPT - NGET)

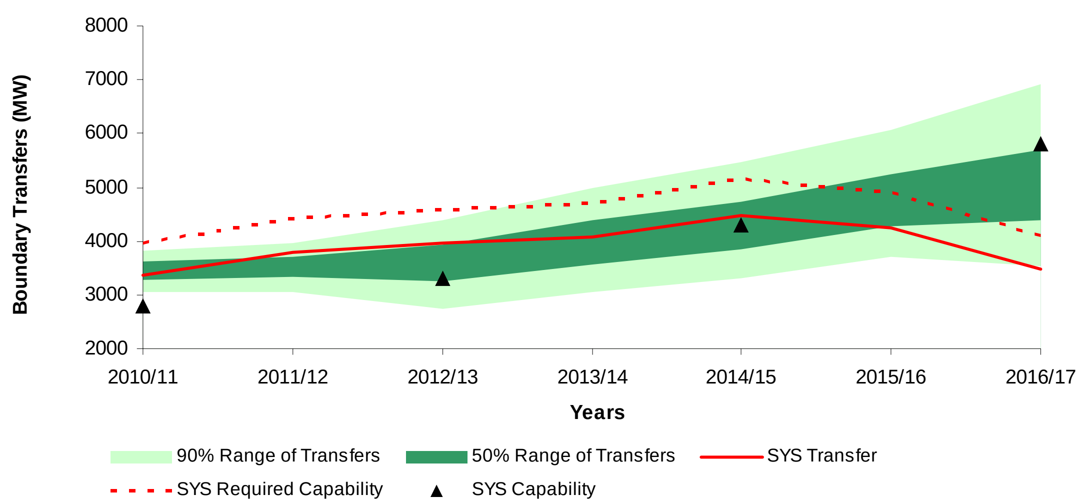


Figure ES.10 - Boundary Transfers and Capability
(Boundary B9: Midlands - South)

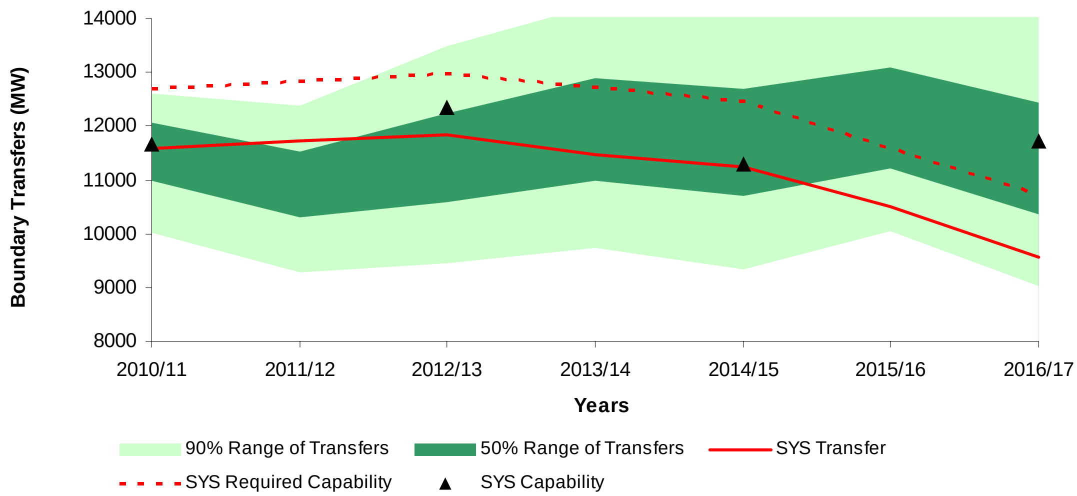


Figure ES.9 and Figure ES.10 show the boundary transfer (SYS Transfer), required capability (SYS Required Capability) and actual capability (SYS Capability); all derived on the basis of the 'SYS Background'. These are displayed against a backdrop (shaded areas) of our current view of the probable transfer 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 25^{th} to the 75^{th} 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 5^{th} to the 95^{th} 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 ES.9, the SYS Planned Transfer lies towards the top of the probabilistic range of Planned Transfers up until 2014/15. There is therefore a chance of lower peak flows than suggested by the SYS background. The actual SYS capability however, is below the SYS Required Capability until 2014/15. Therefore 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 ES.10, the SYS Planned Transfer lies mainly within the range of the probabilistic transfers. At the same time, the SYS capability is lower than the SYS Required Capability up until 2014/15, which indicates a high probability of further reinforcements being required.

This presentation, which is reported in detail in Chapter 8 ("Transmission System Capability") in the main text, is useful for highlighting issues around the timing of transmission reinforcements and also for illustrating future opportunities. Please note that, whilst the 'SYS capabilities' displayed on Figure ES.9 and Figure ES.10 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 Northern 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) all show steady growth in power transfers over the SYS period due primarily to contracted renewable energy developments throughout Scotland. A sudden drop in power flow from north to south happens in 2016 when some LCPD closures are expected. Further increase in new renewable generation in the North will push the boundary transfers higher.

- Boundaries B8 (North to Midlands) and B9 (Midlands to South), B11 (Northeast & Yorkshire), (B12) South & Southwest import, B16 (Northeast, Trent & Yorkshire) and West Midlands import (B17) show mostly constant power flows with some fluctuation due to new generation connections and older generation closures.

- Central London imports (B14) show a trend of a steady increase in transfers reflecting gradually increasing demands and the lack of new generation projects within this zone;

- There is a general trend with reducing transfers across the South Coast import (B10), 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.

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. New technologies are also being investigated and planned for deployment on the transmission system to improve its performance including series reactive compensation and HVDC links.

Opportunities for New Generation and Demand (See Chapter 9)

Generation Opportunities

As in previous years, Figure ES.11 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.

Figure ES.10 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.

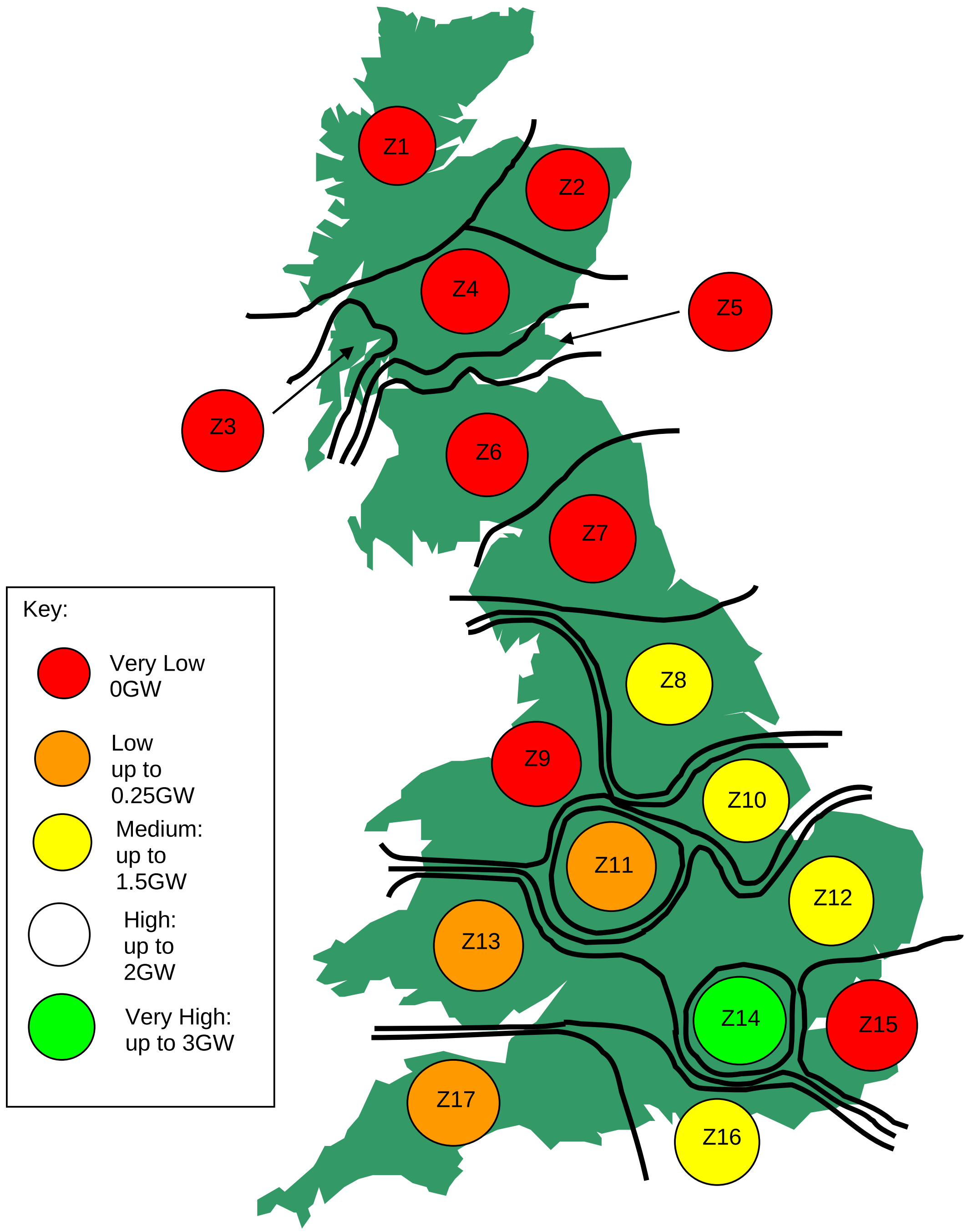
It does not follow that all the generation capacity within an opportunity group could be located at one site within a zone. In some zones, for example the London Zones, a considerable spread would be necessary. Nor does it follow that the capacities indicated for each zone within an opportunity group 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. Elements of this reinforcement have recently been the subject of a Public Inquiry. The project has now been approved by the Scottish Government subject to conditions. It should be borne in mind that any variation in the final commissioning date could impact on the opportunities.

The analyses of boundary power transfers show that, with an overall increase in installed generation capacity of 26.6GW reported between 2009/10 and 2016/17, 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.

Figure ES.11 - GB Generation Connection Opportunities



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.

Transmission Access Review

The current transmission access review is also relevant in the context of future opportunities for generation access to the national electricity transmission system. This review was announced in the Government's Energy White Paper 2007 and is being led by Ofgem and the Department for Energy & Climate Change (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 national electricity transmission system is provided through arrangements with National Grid, acting as NETSO, under the Connection and Use of System Code (CUSC). The CUSC sets out the contractual framework for connection to, and use of, the national electricity 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.

Interim Connect and Manage

The red areas in Figure ES.11 would imply limited opportunity for connection in those zones given the level of transmission reinforcement required. Therefore, whilst Figure ES.11 correctly represents the opportunity for connection to a compliant network, it should be noted that in May 2009, Ofgem announced its intention to grant derogations from the requirements for the transmission infrastructure to comply with SQSS. This relaxation from the industry standards was introduced to facilitate generation projects connecting to the grid by accelerating their grid access dates. This was based on an interim 'connect and manage approach, under which any additional constraint costs incurred by the NETSO are socialised across all users.

As of April 2010, nearly 4GW of existing projects have had their connection dates advanced, with an additional 2.4GW of generation projects in the process of advancing their connection dates. In addition, this approach has allowed a further 6.4GW of new applications to be offered earlier connection dates than would have been the case under previous arrangements.

Enduring Arrangements

The Department of Energy and Climate Change (DECC) is currently progressing with formalising revised arrangements to the grid access regime. The preferred model would introduce Connect and Manage on an enduring basis. All constraint costs, including those arising from the advanced connection, would be socialised equally among all generators and suppliers on a per-MWh basis as they are at present under the Interim Connect and Manage arrangements.

Under Connect and Manage, new generators will able to access the network and start generating as soon as the local enabling works needed to connect them to the network are complete, without having to wait for all wider network reinforcement to be completed. NGET (acting in its role of NETSO) will take any necessary action to manage the resulting constraints on the network.

The second DECC consultation on Improving Grid Access closed on 14th April 2010. The final determination on the enduring arrangements will be announced by DECC in due course.

Strategic Investment

The information contained in this year's SYS reflects some of the recent work undertaken for the Energy Networks Strategy Group (ENSG) – Our Electricity Network – A Vision for 2020. The work carried out for ENSG identifies a set of transmission reinforcements to facilitate the connection of renewable generation to help meet the Government's 2020 climate change targets, there is still further work required to fully agree a revised regulatory regime to deal with this anticipated investment.

Funding has been agreed to undertake pre-construction works which are currently under way and well advanced for the projects needed soonest. A number of the strategic investment projects are now included as base projects in this SYS including the upgrading of the Hutton to Quernmore circuits, installation of series reactive compensation of the Anglo-Scottish circuits and the establishment of a new subsea HVDC circuit route from SPT to NGET. Further strategic investment projects are under development to be delivered beyond the SYS period to 2020 and later.

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 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.

The Offshore Development Information Statement

The Offshore Development Information Statement (ODIS) is produced in accordance with Special Condition C4, and is available at the following location.

https://www.nationalgrid.com/uk/Electricity/ODIS/

The main purpose of the Statement is to facilitate the achievement of the coordinated development of the offshore and onshore electricity grid in Great Britain. The network solutions identified in the Statement represent a vision of how the offshore and onshore reinforcements could be developed; it is the responsibility of individual onshore/offshore network owners to develop detailed designs. In developing these detailed designs it is envisaged that this Statement will provide guidance in determining the optimum solutions.

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Chapter 1

Introduction

Introduction

The 2010 NETS Britain Seven Year Statement (NETS SYS) is published by National Grid Electricity Transmission plc (NGET), acting in its role as National Electricity Transmission System System Operator (NETSO). 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 national electricity transmission system (i.e. the NETS SYS). The Statement is produced in accordance with the obligations placed on National Grid, acting as NETSO, 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 NETS 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 NETS SYS pursuant to their licence obligations.

A key purpose of the NETS SYS is to assist existing and prospective new Users of the national electricity transmission system, whether generators or suppliers of electricity, in assessing the opportunities available to them for making new or additional use of the national electricity 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.

The SYS Structure

For those readers who are unfamiliar with the current market structure, including the British Electricity Trading Arrangements, Chapter 10 (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 Chapter 4 (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 national electricity 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 national electricity 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.

Appendix A (Additional Figures), Appendix B (Data), Appendix C (Power Flows), Appendix D (Fault Levels) and Appendix E (Grid Supply Point Demand Data) present technical information relating to the national electricity 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 NETS SYS is provided by Users and potential new Users of the national electricity 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 SYS Background

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

(i) Demand Background: The "NGET based" demand forecasts rather than the "customer-based" demand forecasts. Both sets of demand forecasts are reported in Chapter 2 (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 Chapter 3 (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 Chapter 6 (The 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 2009, 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 national electricity 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. In the past, these updates WERE published as separate documents, but now the updates have been merged with the Transmission Networks Quarterly Connections Update (TNQCU), which is available at the following location:

http://www.nationalgrid.com/uk/Electricity/GettingConnected/gb_agreements/

The first Update to this 2010 NETS SYS was published in April 2010, and includes the effect of any changes notified since the data freeze date. As in previous years, further Updates will be issued on a regular basis (approximately three month intervals). 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 2009**. Subsequent developments are reported in the Quarterly Updates.

Content Outline

The following gives an outline of the main sections of the NETS SYS, together with the main data items included within each section. The content outline is given in terms of main sections, which correspond broadly to the chapters and appendices in the SYS. There are a number of figures and tables in the NETS SYS that are generic in nature and provided for illustrative purposes. For the sake of conciseness they are not listed here.

The following definitions are used in the sections that follow:

- Year 0 is 2009/10
- Year 1 is 2010/11
- Year 2 is 2011/12
- Year 3 is 2012/13
- Year 4 is 2013/14
- Year 5 is 2014/15
- Year 6 is 2015/16
- Year 7 is 2016/17

<u>Chapter 2 - Demand</u>
This chapter presents the following data:

- historical outturns of actual and weather-corrected peak demand and energy supplied from 2005/06 to Year 0
- daily demand profiles for winter peak, typical winter, typical summer and summer minimum in Year 0
- weekly maximum and minimum demands in Year 0
- annual load duration curve for Year 0
- forecast of peak demand from Year 1 to Year 7 based on data submitted by users, including interconnector, pumped storage and demand management assumptions
- National Grid forecast for demand and electricity requirements from Year 1 to Year 7 for Low, Base and High growth scenarios

The chapter also includes a discussion of the assumptions behind the National Grid Low, Base and High forecasts, and an explanation of demand terminology such as weather corrections.

<u>Chapter 3 - Generation</u>
This chapter provides data on historic, existing and planned generation connected to the transmission network. Historic data is shown from 2005/06 onwards. The data provided includes the following:

- existing and planned station capacities for year 1 to year 7, including ownership and plant type
- main changes in generation capacity from 2005/06 to year 0
- planned capacity additions from year 1 to year 7, indicating those projects that are under construction and those that have consents granted

- planned generation closures from year 1 to year 7, including LCPD (Large Combustion Plants Directive) closures
- unavailable generating units up to year 7
- import and export capabilities of interconnectors
- generating unit data for existing generation, including reactive range and fault infeed
- details of transmission contracted generation planned to connect beyond year 7

An explanation is also given of how generation capacities are defined and the different types of contract that customers have. A link to the ODIS (Offshore Development Information Statement) will also be given.

Chapter 4 - Embedded Generation
This section will present data on installed embedded generation according to the defined levels for large, medium and small power stations for each of the three transmission licensees. The data includes capacity and plant type. Data is also presented on the amount of generation netted off the demand by DNOs at the time of system peak.

Chapter 5 - Plant Margins
This chapter deals with the performance of transmission contracted generation in meeting the GB transmission system demand. The data provided includes the following:

- historic plant margins from 2005/06 to year 0, based on installed generation from the SYS January updates, and actual and weather-corrected peak demands
- generation capacity totals from Year 0 to Year 7, using the four generation backgrounds of existing, under construction, consents granted and all generation, together with the customer-based and NGET Base demands
- plant margins from Year 0 to Year 7, using the four generation backgrounds above, and the customer-based and NGET Base demands
- plant margins from Year 0 to Year 7, for varying levels of wind output, based on the customer-based peak demands

Chapter 6 - Transmission System
This chapter introduces the diagrams in Appendix A & Appendix C, and the data in Appendix B, and also contains the following:

- planned developments on the transmission network from Year 1 to Year 7, for SHETL, SPT and NGET areas
- planned developments on the transmission network that either take place beyond year 7 or are associated with future connections that take place beyond year 7

A brief discussion of how the power system is controlled and operated with reference to the main types of equipment installed on the system will be provided.

Chapter 7 - Transmission System Performance
This chapter introduces the power flow diagrams presented in Appendix C, and also presents data and analysis on the following:

- daily demand profiles for winter peak, typical winter, typical summer and summer minimum in Year 0, showing energy supplied by plant type
- ranking order of generation operation for Year 1 to Year 7
- zonal demand, studied generation and transfers, for SYS Study Zones Z1 to Z17, for Year 1 to Year 7 inclusive for winter peak
- boundary demand, studied generation and transfers, for transmission boundaries B1 to B17, for Year 1 to Year 7 inclusive for winter peak
- transmission losses by circuit type for Year 1 to Year 7 inclusive for winter peak
- zonal transmission losses for SYS Study Zones Z1 to Z17, based on year 1

This chapter also discusses the method used for the calculation of fault levels, and introduces the fault level results in Appendix D.

Chapter 8 - Transmission System Capability

This chapter presents the results of the boundary capability studies. For each boundary the following is given:

- planned transfer, required capability, actual capability for Year 1, Year 3, Year 5 and Year 7
- probabilistic transfers for Year 1 to Year 7 inclusive
- a commentary for each boundary

A table of additional construction schemes that are identified for network compliance as a result of the boundary capability studies is also provided, and a discussion of the ENSG (Electricity Networks Strategy Group) report.

Chapter 9 - Opportunities

The main purpose of this chapter is to provide a commentary on opportunities for connection to the transmission network for demand, generation and interconnector customers. Hence, the following is provided:

- zonal demand and studied generation for each SYS study zone
- a commentary on opportunities for the connection of generation in each SYS study zone
- reactive utilisation (metered output) from April 2005 to March 2010

This chapter also includes a discussion of the TAR (Transmission Access Reform) and ICM (Interim Connect and Manage)

Chapter 10 – Market Overview

This chapter section provides a discussion on BETTA (British Electricity Trading and Transmission Arrangements), including market structure, key documents, the System Operator's role and obligations, and participants requirements.

Appendix A - Geographic & Schematic Diagrams

Geographical drawings of the national electricity transmission network will be provided, based on the existing transmission network. The maps will show the following:

- location of existing Large Power Stations
- DNO boundaries
- main system boundaries and SYS study zones
- existing National Parks

A link to the Charging & Revenue web pages will be provided where the latest version of the geographic diagram of generation Use of System tariff zones can be viewed.

Each Licensee will produce schematic diagrams for their own networks. The following will be produced:

- existing transmission system as at the main SYS data freeze date (31 December 2009)
- reactive compensation equipment, with the Year 1 transmission network as background
- Generation Use of System Tariff Zones, with the Year 1 transmission network as background
- main system boundaries and SYS study zones, with the Year 7 transmission network as background

Appendix B - Technical Data

Technical data for the national electricity ransmission network will be provided as follows:

- data for existing and planned substations, giving substation code, operating voltage, demand tariff zone, generation tariff zone and LV shunt susceptance
- tables of transmission circuits for winter Year 1, giving circuit type, circuit length, circuit parameters and circuit ratings
- planned changes to transmission circuits for Year 2 to Year 7, giving the type of change and the equivalent data supplied for existing circuits
- tables of grid supply transformers for winter Year 1, giving transformer parameters and rating
- planned changes to grid supply transformers for Year 2 to Year 7, giving the type of change and the equivalent data supplied for existing transformers

- typical parameters for transformers, QBs and SVCs
- reactive compensation equipment for winter Year 1, giving equipment type, operating voltage, and reactive ranges
- planned changes to reactive compensation equipment, for Year 2 to Year 7, giving the type of change and the equivalent data supplied for existing compensation equipment
- indicative switchgear ratings, including voltage level, breaker type nominal rating, three-phase and single-phase initial peak, RMS break and peak break ratings

Appendix C - Power Flow Diagrams

Each Licensee will produce power flow diagrams for their own network, and NGET will collate the three separate sets of diagrams into the NETS SYS document. The diagrams will show power flows on all transmission circuits for year 1 to year 7 inclusive.

Appendix D - Fault Levels

Each licensee will calculate fault levels on their networks for Year 1 to Year 7 inclusive for winter peak. The quantities calculated will be:

- node name
- voltage level (kV)
- three-phase initial peak current (kA)
- three-phase RMS break current (kA)
- three-phase DC break current (kA)
- three-phase peak break current (kA)
- single-phase initial peak current (kA)
- single-phase RMS break current (kA)
- single-phase DC break current (kA)
- single-phase peak break current (kA)

Appendix E - Supply Point Demands

This appendix presents the following data:

- supply point demands at time of supply point peak and system peak, power factor and generation for Year 0 to Year 7, for winter peak conditions, together with node name and customer name for each supply point
- supply point demands at time of system minimum, power factor and generation for Year 0, for summer minimum, together with node name and customer name for each supply point

Other Sections

Other sections of the NETS SYS document include:

- legal disclaimer
- foreword
- executive summary, which will discuss the main points together with headline figures from the main statement
- introduction
- contact details for the three transmission companies
- a list of references, useful documents and websites
- glossary

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Chapter 2

Electricity Demand

Introduction

This chapter presents forecasts of electricity demand to be met from the National Electricity Transmission System. In this Statement, the main forecasts are based on NGET's own forecasts rather than based on Users' forecasts. Users' forecasts were submitted in June 2009 whilst NGET's forecasts benefit from being based on demand outturn seen in 2009/10, therefore NGET's forecasts are used as the main forecasts.

The main forecasts, which is based on NGET's forecast, together with the generation and transmission backgrounds described in Chapter 3 ("Generation") and Chapter 6 ("National Electricity Transmission System") respectively, form the basis of the SYS background upon which most of the studies presented in this Statement are based.

Information submitted by Customers (transmission system 'Users') who take, or propose to take, electricity from the high voltage system is also presented. The 'User'-based forecasts, includes details of individual Grid Supply Point demands.

Alternative 'High' and 'Low' scenario forecasts are also 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.

ACS Peak Demand

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

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 Transmission System and accordingly take account of any diversity between the individual peak demands on each of the systems of the three Onshore 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 Transmission System to be met by Large Power Stations (directly connected or embedded), Medium and Small Power Stations which are directly connected to the Transmission System and by electricity imported directly into the 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 Chapter 4 ("Embedded and Renewable Generation"); Tables 4.1 and F.3 are of particular relevance.

Losses

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.

Exports
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 100MW export is assumed for the time of the peak demand between 2010/11 to 2013/14; 250MW export from 2014/15 onwards.

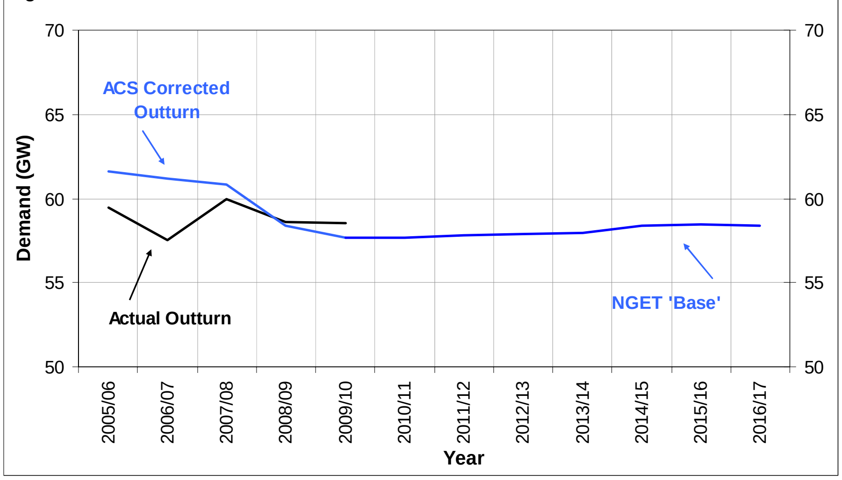
Unrestricted/Restricted Demand
Infrastructure planning for the transmission system continues to be based on ACS 'unrestricted' demands – a prudent approach to transmission planning made on the basis that demand control cannot be fully relied upon to be enacted at peak times. Historical 'unrestricted' 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 0.6 GW, are estimated from historical data in recent years. 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.

Peak Demand Outturn

Figure 2.1 shows recent actual and ACS peak demands along with the latest NGET 'Base' forecasts of ACS peak demand on the Transmission System. Correcting historical peak demands to ACS conditions enables underlying peak demand patterns and trends to be more readily observed.

Figure 2.1 - Historical Outturn & NGET's 'Base' Peak Demand Forecast



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 external interconnection exports.

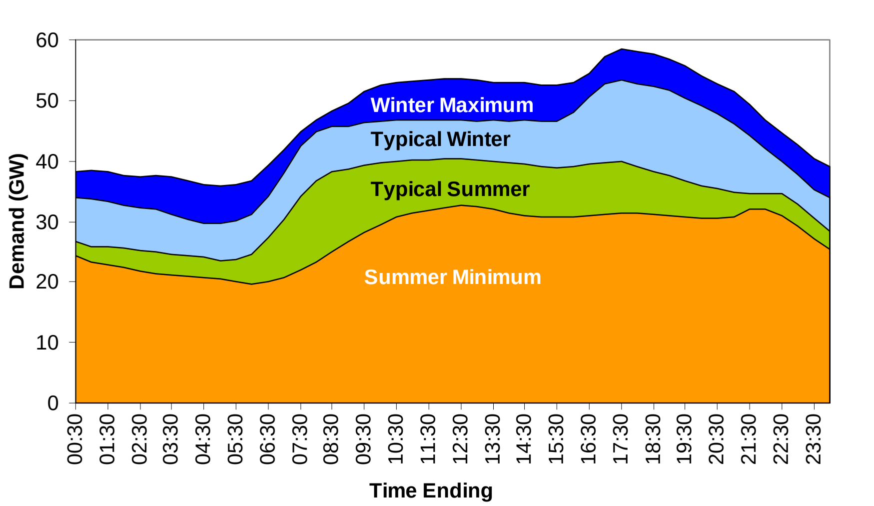
For many of the above factors, the effects are generally small over time and may have little impact on the year-on-year changes in transmission system demand. Demand started to fall in 2006, initially due to price and energy efficiency measures, thereafter due to the recession (official recession. period was April 2008 – September 2009). Another significant factor is the weather, which can cause wide variations in demand, especially peak demand, from one year to the next. Actual peak demand in the winter of 2009/10 was 59.1 GW, which was 0.1GW lower than in the previous winter.

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 2009/10 to ACS conditions yields an 'unrestricted' peak of 58.2 GW, which is 0.8 GW lower than previous winter's ACS peak. ACS corrected peak demand is 0.9 GW lower than outturn.

Demand Profiles

Figure 2.2 presents daily demand profiles for the days of maximum (07/01/10) and minimum (02/08/09) demand on the Transmission System in 2009/10 and for days of typical winter (02/12/09) and summer (11/06/09) weekday demand. Please note that these demands are shown exclusive of station transformer, pumping demand and interconnector exports.

Figure 2.2 - GB Summer and Winter Daily Demand Profiles in 2009/10



Key points of interest are: -

(i) Maximum & Typical Winter Profiles (Weekday)

- 00:00h - 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 2009/10 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 - Weekly Maximum and Minimum GB Demands in 2009/10

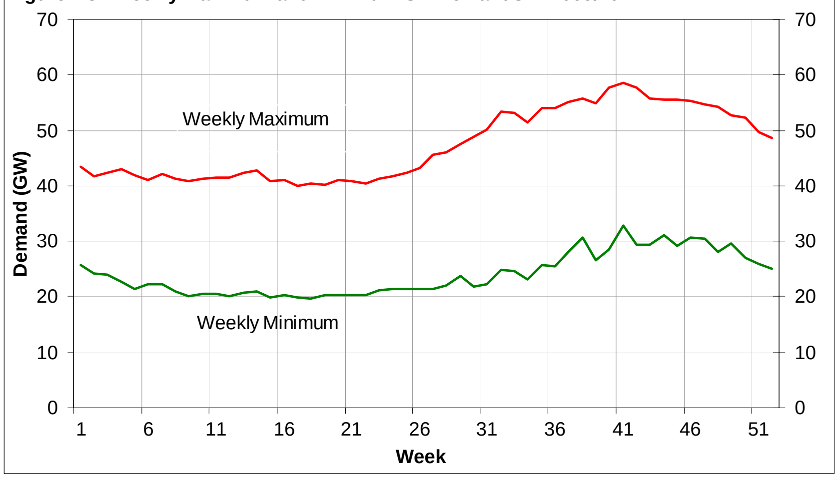
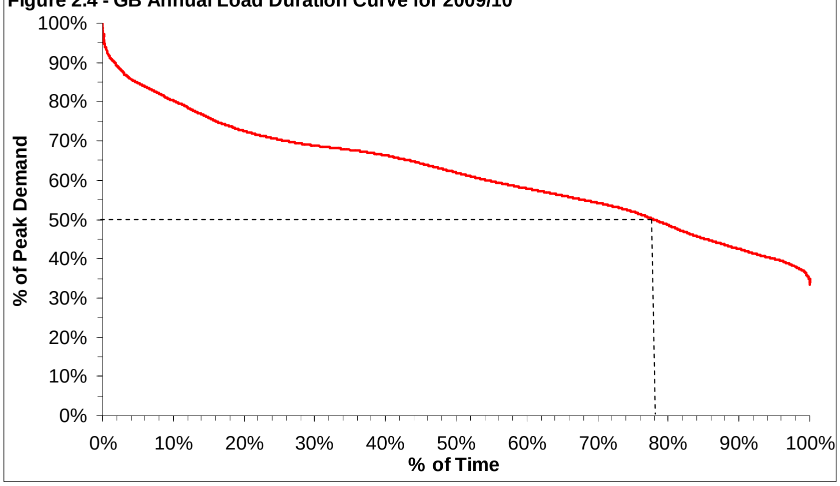


Figure 2.4 shows the annual load duration curve for 2009/10. Based on demand data for every half hour of the year, it shows the percentage of time in the year against the proportion of the year's peak. For example, demand exceeded 50% of the annual peak for 78% of the time.

Figure 2.4 - GB Annual Load Duration Curve for 2009/10



National Grid Forecasts

Background

As outlined earlier in this chapter, NGET's own forecasts, together with the generation and transmission backgrounds, form the basis of the SYS background upon which most of the studies presented in this Statement are based. To be consistent with the rest of this Statement, "ACS Peak Demand" is now inclusive of losses and exports to External Systems; but exclusive of station demand. No pumping demand at pumped storage stations is assumed to occur at peak times.

Row 3 of Table 2.1 shows the main forecast “ACS peak 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 Demand excluding station demand should be used where relevant to avoid it being double-counted. This demand increases from the outturn of 57.6 GW in 2009/10 to 58.4 GW by 2016/17, which represents a slow gradual increase of 1.2% over the period.

For completeness, Row 1 of Table 2.1 presents NGET’s demand forecasts including power station demand. In addition, row 7 of Table 2.1 presents NGET’s demand forecasts excluding exports across External Interconnections and power station demand. This forecast is compatible with the generation ranking order of Table F.4, which treats exports as negative generation. Table F.4 is presented in Chapter 7 (”Transmission System Performance”) and included in Appendix F.

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 for energy efficiency savings, combined heat and power and renewables is assumed, resulting in stronger growth in embedded generation. In contrast, in the high demand scenario circumstances bring a much slower take-up of such schemes and hence slower growth in embedded generation. These assumptions, along with variations for other factors such as economic growth and fuel prices, result in a fairly wide range of outcomes for transmission system demand.

Details of NGET's peak demand and electricity requirements projections and the main economic assumptions underlying them are given in Tables 2.3 – 2.5. (Please note that the central economic forecasts on which they are based have been provided by Experian Business Strategies).

NGET’s ‘Base’ Forecast

The economic background is an important element of NGET’s demand forecasts. The UK economy emerged weakly from an 18-month recession in the fourth quarter of 2009. GDP contracted by 4.9% over 2009. Economic recovery is expected to be slow, constrained by an uncertain global background and public and private sector debt problems. GDP is expected to grow by only 1% in 2010, returning consistently to the historic trend rate of between 2% to 2.5% pa only in 2013. Under this scenario, GDP growth averages 0.9% over the period 2009 to 2015 inclusive (1.8% after 2009).

Total annual electricity requirements is projected to fall in 2010/11 but then gradually increase to 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.

New CHP and renewable generating capacities, which are embedded within distribution networks, if utilised, can reduce the growth in peak demand seen on the transmission system.

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. Over the period of this forecast, an initial slow growth is assumed for CHP, with electrical capacity reaching 8.6 GW by 2016/7.

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. The EU climate packages set the goal of increasing renewable energy's share of the market to 20% for 2020, which equates to approximately 35% of electricity from renewable sources. For the UK, the equivalent figures are 15% and 30% respectively. This clearly signifies more renewable generation needs to be in place. The NGET 'Base' forecast assumes 8.2% of consumption being met from qualifying renewables in 2010/11 against the target of 10.4%, and 18.6% by 2015/16 against a target of 15.4%.

In the 'Base' forecasts, peak demand is projected to increase by 0.2% p.a., compared with 0.9% p.a. growth projected for overall electricity use by end-users. The difference can be deemed to be offset by embedded generation.

The 'Base' forecast assumes exports to Northern Ireland via the Moyle Interconnector at peak times of 100MW between 2010/11 and 2013/14 and 250 MW from 2014/15 onwards, with up to 1 TWh projected annually until 2015/16. In addition, the "East/West" interconnection between Wales and the Irish Republic is expected to be exporting 250 MW at peak from 2011/12, and up to 800 GWh per annum.

With regard to the External Interconnection between England and France, no exports are projected for system peak times, though an increase in export to France is expected with up to 3.5TWh p.a. over the duration of this forecast.

In summary, electricity usage by end-users is projected to increase by 0.9% p.a. Annual electricity requirements on the Transmission System was 325 TWh in 2009/10 and the 'Base' forecast shows an initial decline and then gradually recover to 327 TWh by 2016/17 ACS 'unrestricted' peak demand was 57.6 GW in 2009/10, with forecast showing 0.2% growth p.a. reaching 58.4 GW by 2016/17.

NGET's High Growth Scenario

This upside scenario is based on more optimistic assumptions about factors affecting transmission system electricity demand growth over the medium term. This scenario (see Table 2.5) is based on the possibility that the recovery will gain strength sooner than expected due to an earlier than expected revival in consumer spending and/or a boost to exports from strengthening eurozone activity and a weak pound. Under this scenario, GDP growth averages 1.7% over the period 2009 to 2015 inclusive (2.8% after 2009). This results in greater use of energy, with end-users usage averaging 1.8% p.a. With slower rates of take-up assumed for both CHP and renewable generation embedded within distribution networks, and slower energy efficiency savings, annual electricity requirements on the Transmission System is expected to rise by 1.3% per annum, from 325 TWh in 2009/10 to 354 TWh by 20016/17. ACS peak demand increases from 57.6 GW to 63.3 GW over the same period, with growth of 1.4% p.a.

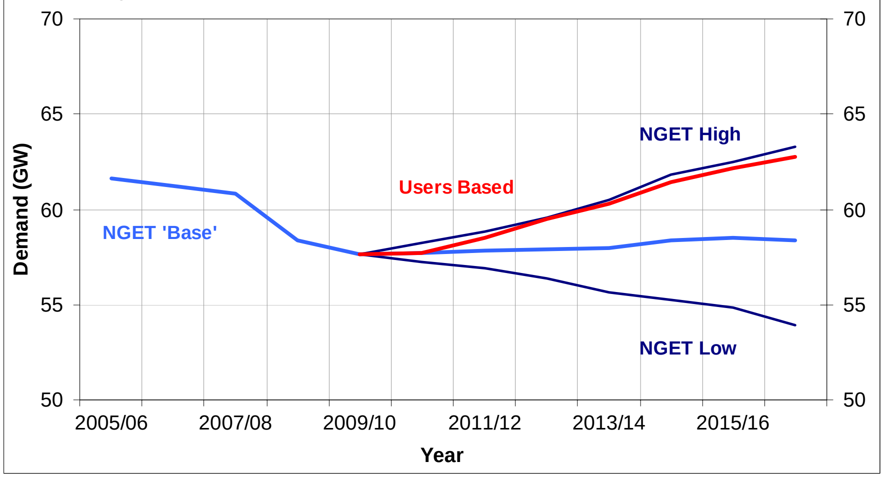
NGET's Low Growth Scenario

This downside scenario (see Table 2.5) is based on the possibility that the recovery falters due to the withdrawal of government support measures due to pressure on government finances. Under this scenario, GDP growth averages 0.2% over the period 2009 to 2015 inclusive (1.0% after 2009). A particularly high profile is assumed for environmental issues, with energy efficiency schemes for domestic and business customers heavily promoted; faster growth in 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 transmission system to decline by 1.0% p.a. 325 TWh in 2009/10 to 302 TWh by 2016/17. ACS peak demand similarly declines by 0.9% p.a., from 57.6 GW to 53.9 GW over the same period.

'Users' Based Forecasts

As explained earlier in this chapter, the main forecasts are based on NGET's own forecasts rather than based on Users' forecasts. NGET's 'base' demand forecasts form part of the SYS background upon which most of the studies presented in this Statement are based. For comparison, 'User'-based peak demand forecasts are presented in this Statement. These are obtained from the aggregation of 'User' submissions (see Table 2.3).

Figure 2.5 - Comparison of Users-Based Forecast and NGET's Projections



When compared with NGET's 'base' projections, the 'User'-based forecasts show year-on-year growth (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 and the growth of demand met by embedded generation.

Throughout the period covered by this year's forecast, the User-based forecast is more optimistic than NGET's 'Base' forecast, and throughout the years, it is in line with NGET'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 2008/09. NGET forecasts benefit from being based on demand outturn seen in 2009/10.

It is explained in 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 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 (2009/10) 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.

Demand on the Grid Supply Points (GSPs)

Grid Supply Points (GSPs) are the points of connection between the 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 system peak. In Appendix E, tables E.1.0 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 system peak. These demands are measured at the GSP and accordingly include distribution losses but 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 Chapter 6 under ”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 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, table E.2.0 provides GSP information at the projected time of the minimum 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, the tables in Appendix E also list Large Power Stations connected to GSPs or embedded in the distribution networks behind GSPs, together with demand power factors.

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 Chapter 4 ("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 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 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 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 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 Dependant 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 (50^{th} 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 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 at the end of this chapter provides a generalised illustration of the definition and also aids comparison with other demand terms in current usage.

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 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 Demand, with the generation used to meet ACS Peak 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 discussed in Chapter 3 (”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 Chapter 4 (”Embedded and Renewable Generation”).

The SYS definition of “ACS Peak Demand” is demand including exports to external systems and pumped storage pumping demand, but excluding station transformer demand.

Please note that the SYS definition of “ACS Peak Demand” is not in line with the Grid Code definition of "National Electricity Transmission System Demand", which includes exports to external systems, pumped storage pumping demand and station transformer demand. Also, this is not the same as the Grid Code definition of "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 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 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 2.6 - ACS Peak GB Demand

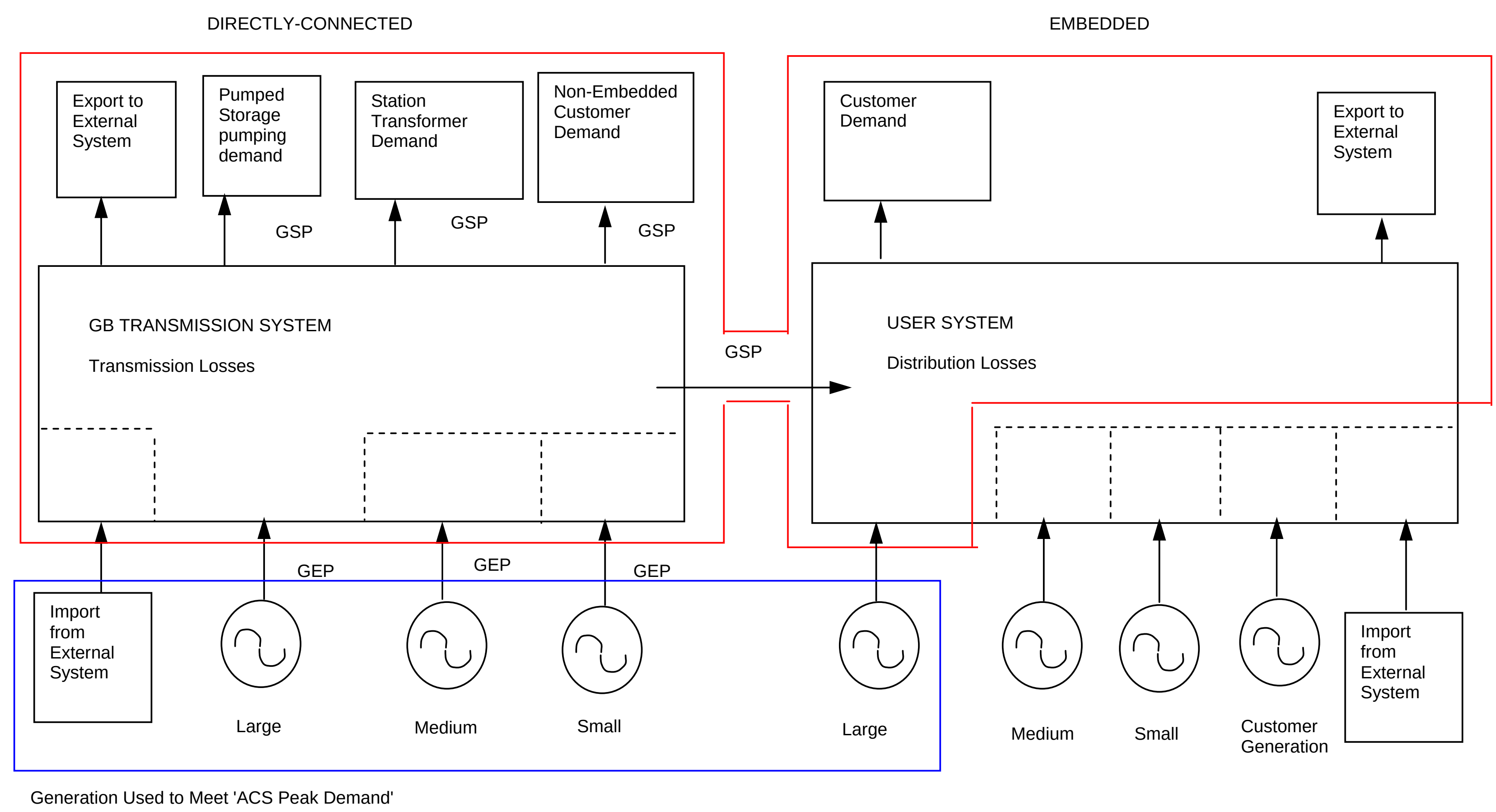


Table 2.1 - NGET's 'Base' ACS Peak Demand Forecasts (GW)									
Forecast	**Description**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
1	ACS Peak incl Station Demand and Exports to External Systems	58.2	58.3	58.4	58.5	58.6	59.0	59.1	59.0
2	Station Demand	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
3	ACS Peak excl Station Demand and Exports to External Systems (for plant margin evaluation)	57.6	57.7	57.8	57.9	58.0	58.4	58.5	58.4
4	Export to N Ireland via Moyle Interconnector	0.0	0.1	0.1	0.1	0.1	0.3	0.3	0.3
5	Export to Republic of Ireland via "East/West" Interconnector	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3
6	Export to France via Sellindge Interconnector	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	ACS Peak excl Station Demand and Exports to External Systems (for ranking order & SQSS studies, where exports to External Systems are treated as negative generation)	57.5	57.6	57.5	57.6	57.6	57.9	58.0	57.9

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	59.7	61.6	350.9	349.2
2006/07	57.8	61.2	342.5	345.3
2007/08	60.1	60.8	343.4	346.0
2008/09	58.6	58.4	335.5	331.6
2009/10	58.5	57.6	327.8	325.4

Table 2.3 - NGET's ACS Peak Demand Forecasts & Users' Peak Demand Forecast				
Year	**ACS Peak Demand (GW) Low Scenario**	**ACS Peak Demand (GW) Base Forecast**	**ACS Peak Demand (GW) High Scenario**	**Users' Peak Demand Forecast**
2009/10	57.6	57.6	57.6	57.6
2010/11	57.2	57.7	58.2	57.7
2011/12	56.9	57.8	58.9	58.5
2012/13	56.4	57.9	59.6	59.5
2013/14	55.7	58.0	60.5	60.3
2014/15	55.2	58.4	61.8	61.4
2015/16	54.9	58.5	62.5	62.1
2016/17	53.9	58.4	63.3	62.8

Table 2.4 - NGET's Annual Electricity Requirement Base Forecast and Scenarios			
Year	**Annual Electricity Requirements (TWh) Low Scenario**	**Annual Electricity Requirements (TWh) Base Forecast**	**Annual Electricity Requirements (TWh) High Scenario**
2009/10	325.4	325.4	325.4
2010/11	321.2	323.7	326.8
2011/12	318.9	323.9	329.8
2012/13	315.8	324.2	333.7
2013/14	312.6	325.6	339.7
2014/15	312.2	330.1	349.3
2015/16	309.0	329.6	351.9
2016/17	301.8	326.9	354.3

Table 2.5 - NGET's Base Forecast and Scenarios Economic Assumptions				
Forecasts (% per Annum)	**GDP**	**Household Disposable Income**	**Manufacturing Output**	**Service Sector Output**
NGET 'Base' Forecast 2008/09 - 2015/16	0.9	2.3	-0.4	1.1
Low Growth Scenario 2008/09 - 2015/16	0.2	0.6	-1.6	0.5
High Growth Scenario 2008/09 - 2015/16	1.7	3.9	0.9	1.8

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Chapter 3

Generation

Introduction

This chapter presents information on all sources of generation, which are used to meet the ACS Peak Demand as defined in the Glossary and presented in Chapter 2 (Electricity Demand). Accordingly, this chapter reports on all power stations directly connected to the national electricity 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).

Chapter 2 (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 Chapter 4 (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 some stations may close, and some of the proposed projects may 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, the Magnox plants at Oldbury and Wylfa, where closure dates have been published by BNFL Magnox Electric, are shown as closing over the period. It has also been assumed that plant that has opted out of the LCPD obligation will not generate from 2016 onwards.

Please note also that the new nuclear generation contracted to connect at Bradwell and Dungeness has not been included in the analysis of boundary capabilities in Chapter 8.

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 NETS SYS in that it is treated as "Transmission Contracted". Its capacity is not netted off the demand forecasts submitted by Users but, instead, is included as generation capacity used to meet the ACS Peak Demand.

The SYS Background

The generation background presented in this chapter, together with the ‘User’ based demand background and the transmission background described in Chapter 2 (Electricity Demand) and Chapter 6 (The 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 2009.

Consents (S36 and S14) and Under Construction Status

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 Chapter 10 (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 under construction, for which section 36 and/or section 14 consents have been given. Table 3.3 lists power stations, not yet under construction, for which section 36 and/or section 14 consents have been given. The information in Table 3.2 and Table 3.3 is consistent with the TEC Register as at the main Data Freeze Date. The TEC Register can be viewed on the National Grid website:

http://www.nationalgrid.com/uk/Electricity/GettingConnected/TEC+Register/

Finally, Figure A.1.4 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 F.1 in Appendix F presents details of all power stations falling within the scope of this chapter including the output capacity of each from 2009/10 to 2016/17. Amongst other things, Chapter 3 (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.

Table 10.2 in Chapter 10 shows the relationship between the different types of agreements and capacities. In Table F.1, where the type of Bilateral Agreement is either a BCA or a BEGA, the capacity for that station is a TEC value. Where the type of Bilateral Agreement is given as a BELLA, the station is included by virtue of its size. The capacities of new generation projects are shown as zero up until the year in which the project is contracted to commission.

In Table F.1 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.

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. The SYS Study Zones are explained in Chapter 6 under "SYS Boundaries and SYS Study 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 F.1. 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 system peak demand. An example is Table F.4 (Generation Ranking Order) which is included in Appendix F and described in Chapter 7 (Transmission System Performance). There are a number of other differences between Table F.1, which is intended to provide information on the formal contracted (TEC) position, and Table F.4, 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.

The capacities in Table F.1 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 Chapter 4 (Embedded and Renewable Generation).

It should be remembered that Table F.1 reflects the current contracted position and takes 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) has required large electricity generators to meet more stringent air quality standards since 1 January 2008. Plant that 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 not possible 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.

For the 2010 NETS SYS, it has been assumed that plant that has opted out of the obligation will not generate from 2016 onwards.. 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 power stations listed in Table F.1 are generally made up of individual generating units. The 'effective output' capacity of each Generating Unit is given in Table F.2 in Appendix F 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 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 F.2 reflects the contracted position for the winter peak of 2009/10 as known at the data freeze date of 31 December 2009.

Three phase fault infeeds and reactive ranges are also given and these are at the interface between the Generating Unit and the national electricity 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 3.5 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 2009/10. 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 3.5 does not include any subsequent increases or decreases in capacity of plant commissioned before 2005. Table 3.5 also includes plant closures that have taken place from 2005/06 to 2009/10 inclusive. These closures are indicated by negative values of capacity, such as in the case of Dungeness A and Sizewell A. Both of these stations were actually closed on 31 December 2006, which is within the 2006/07 winter peak period.

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 by the winter peak of 2009/10 is classified as either 'existing' or 'under construction'.

The net total of capacity is included in the penultimate line of Table 3.5. This may be used as an indicator as to the level of activity over the period.

Table 3.6 lists the changes in the contracted capacity of generation, which are contracted to commission, over the period from the winter peak of 2010/11 to the winter peak of 2016/17 inclusive.

The status of each development is shown in terms of whether the station is existing, under construction and whether 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 3.6. This may be used as an indicator to the future level of activity over the period. 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 3.7 complements Table 3.6 by providing an overview of the generation capacity additions over the period from 2010/11 to 2016/17 inclusive. Table 3.7 separately identifies the capacity of future plant by type and according to whether the necessary consents have been obtained.

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 3.8 lists notified generation disconnections (closures) from the year 2009/10 to 2016/17 inclusive. 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.

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 up to and including the winter peak of 2015/16. The affected stations are however, shown as closed from 2016/17 onwards.

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, the customer 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 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 3.9 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 3.9 may be taken as an equivalent reduction in power station TEC.

To provide a more complete picture, Table 3.9 includes the effect of the LCPD closures detailed in Table 3.8. Closures are indicated by negative values in Table 3.9.

Table 3.9 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 National Electricity 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 an External Interconnection with the Republic of Ireland system is planned for 2011/12. The opportunities for making use of these External Interconnections are outlined in Chapter 9 (Opportunities). Table 3.10 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 3.10 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 F.1 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 500MW 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 250MW export from Wales to the Republic of Ireland. Table F.4 in Appendix F (Generation Ranking Order) described in Chapter 7 (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 F.4 includes an export from Scotland to Northern Ireland over the Interconnector of 250MW, which is shown as negative generation. Table F.4 also includes an export from Wales to the Republic of Ireland over the Interconnector of 250MW, 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 National Electricity 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 Chapter 6 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 3.10.

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 National Electricity transmission system.

Republic of Ireland Link

A DC link for interconnection with the Republic of Ireland electricity system is planned to commission by 2011. The link will be of capacity up to 500MW, capable of bi-directional flow, and will be connected at Deeside 400kV substation. At peak times it is expected that the link will normally be used for exports from the National Electricity transmission system.

Generation Mix

Figure 3.1 illustrates the main changes, from 2009/10 onwards, in the generation capacity of transmission contracted plant. For the underlying detail please refer to: Table 3.6 (changes in station capacity); Table 3.8 (closures); and Table 3.9 (unavailable plant). In including closures and unavailabilities, it should be noted that generators are not required to provide formal notification of disconnections or decommissioning until 6 months prior to the event.

An 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 up until 2015/16 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 affected stations are however, shown as closed from 2016/17 onwards.

The effect of the LCPD closures can be seen in 2016 in Figure 3.1. These closures are partially offset by two new coal plants, one of which is contracted to connect at Tilbury, and the other has been assumed will be built at Kingsnorth.

The majority of the new capacity up to 2016/17 is made up of CCGT and wind generation. Due to the level of contracted activity beyond 2016/17, the capacities of new contracted generation projects up to 2025 have been included in Figure 3.1. Details of individual projects can be found in Table 3.14. Table 3.14 lists generation projects for which an appropriate bilateral agreement is in place but which are scheduled to commission beyond the scope of this NETS SYS (i.e. after 2016/17). Figure 3.1 illustrates the amount of new nuclear capacity that is contracted to connect in the later years up to 2025, which makes up the bulk of the new capacity from 2016/17 onwards.

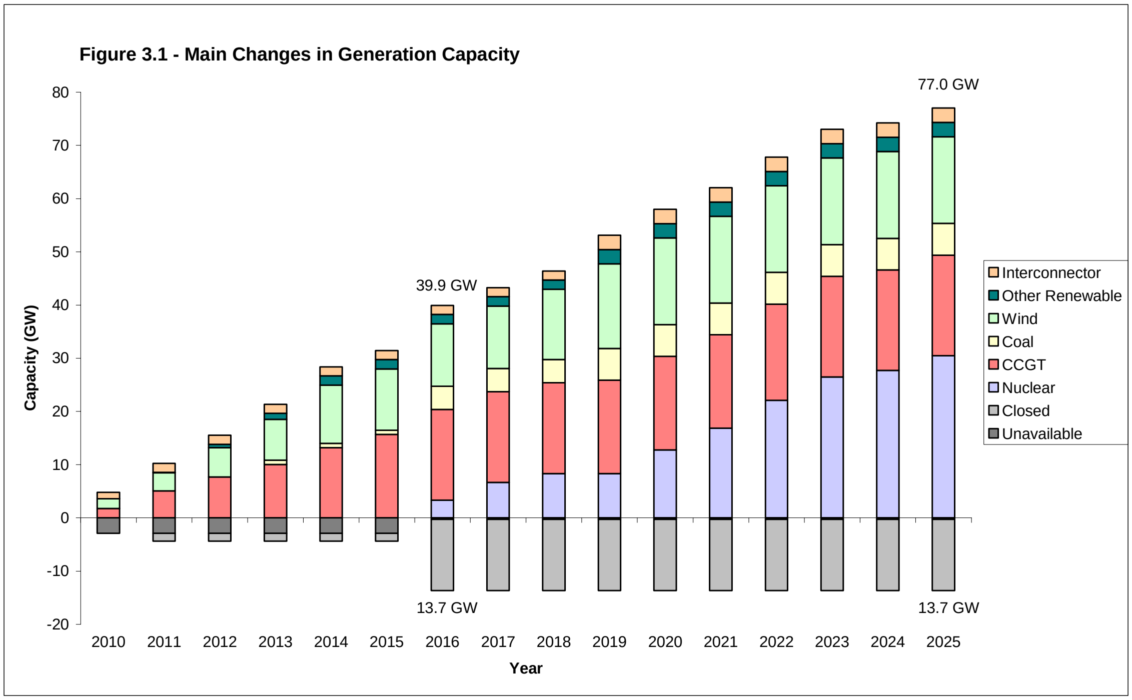


Figure 3.2 illustrates the generation mix from 2009/10 to 2016/17 and includes all transmission contracted generation whether existing or planned (i.e. the 'SYS background') based on Table F.1. In Figure 3.2, the different fuel types are given in an illustrative order of operation. Please note, however, 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. Figure 3.2 shows a reduction in coal capacity used to meet the demand in the final year, due to the effect of the assumed LCPD closures. The closure of Magnox plant by 2011/12 can also be seen. These closures are offset by growth in CCGT, new coal capacity, onshore and offshore wind, other renewables (mainly biomass, biopower and woodchip) and new interconnector.capability.

In considering the above information it is important to note the following 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;
- the additional contracted generation capacity due to connect from 2010/11 onwards includes those projects that are under construction and those that are not under construction; Table 3.7 summarises new capacity by plant types and project status, as at the data freeze date of 31 December 2009; and
- the full import capability has been assumed for the External Interconnections with France and the Netherlands.

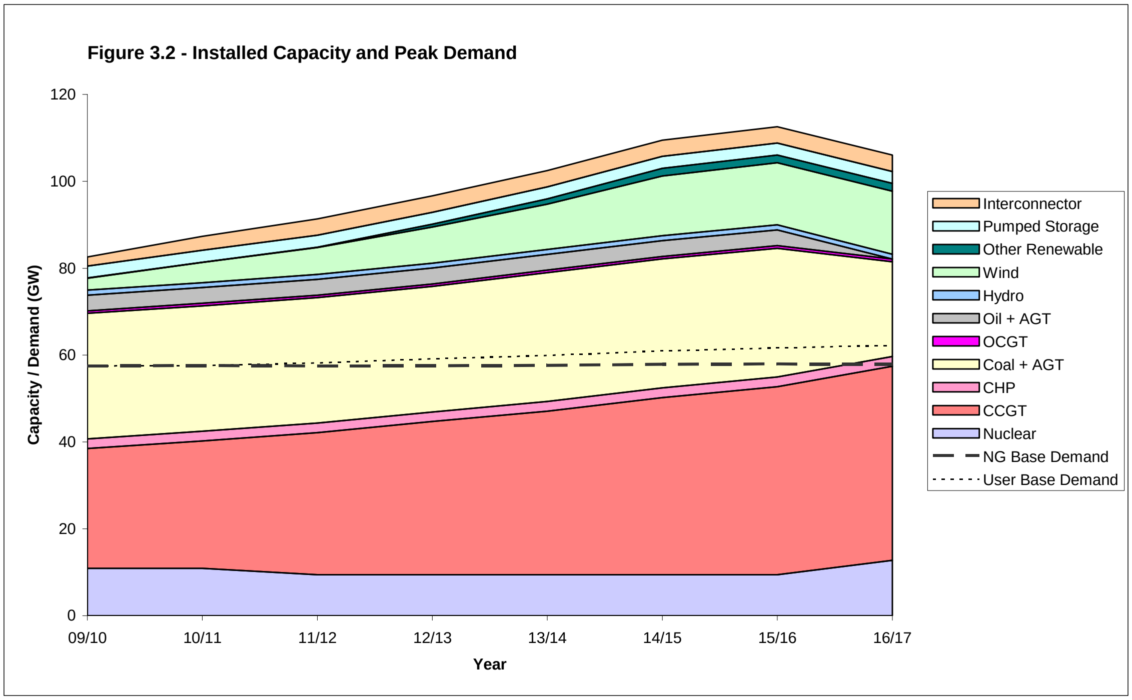


Figure 3.2 also includes the peak demand forecasts for 2009/10 to 2016/17, both for the NGET 'Base' forecast and the customer-based demand forecast, superimposed on the generation mix. This gives an indication of the apparent surplus of generation over demand, which is discussed further in Chapter 5 (Plant Margin). The peak demands shown in Figure 3.2 exclude station demand and also exclude exports to Northern Ireland and the Republic of Ireland, making them compatible with Table F.1, 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.

As a point of interest, Figure 3.3(a), Figure 3.3(b), Figure 3.3(c) and Figure 3.3(d) indicate how generation was actually used to meet demand on each of the four days referred to in Figure 2.2 of Chapter 2. These are the winter maximum (Thursday, 07/01/10), typical winter (Thursday, 03/12/09), typical summer (Thursday, 11/06/09) and summer minimum (Sunday, 02/08/09) respectively.

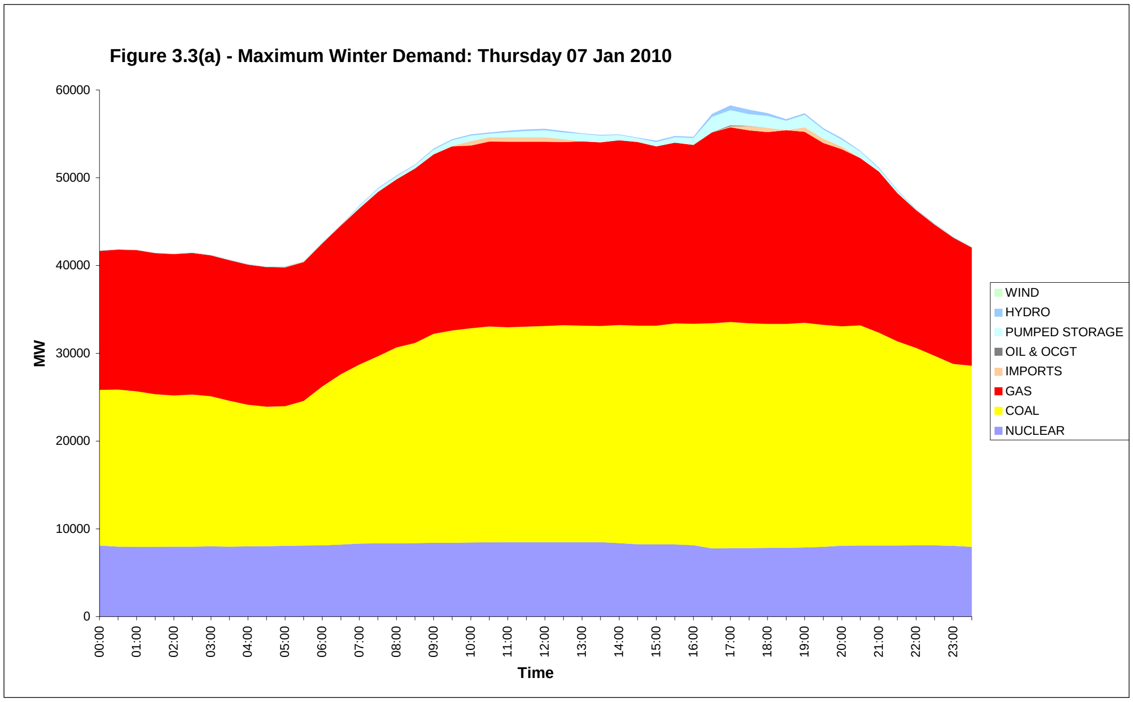


Figure 3.3(a) - Maximum Winter Demand: Thursday 07 Jan 2010
MW
0
10000
20000
30000
40000
50000
60000
00:00
01:00
02:00
03:00
04:00
05:00
06:00
07:00
08:00
09:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
Time
WIND
HYDRO
PUMPED STORAGE
OIL & OCGT
IMPORTS
GAS
COAL
NUCLEAR

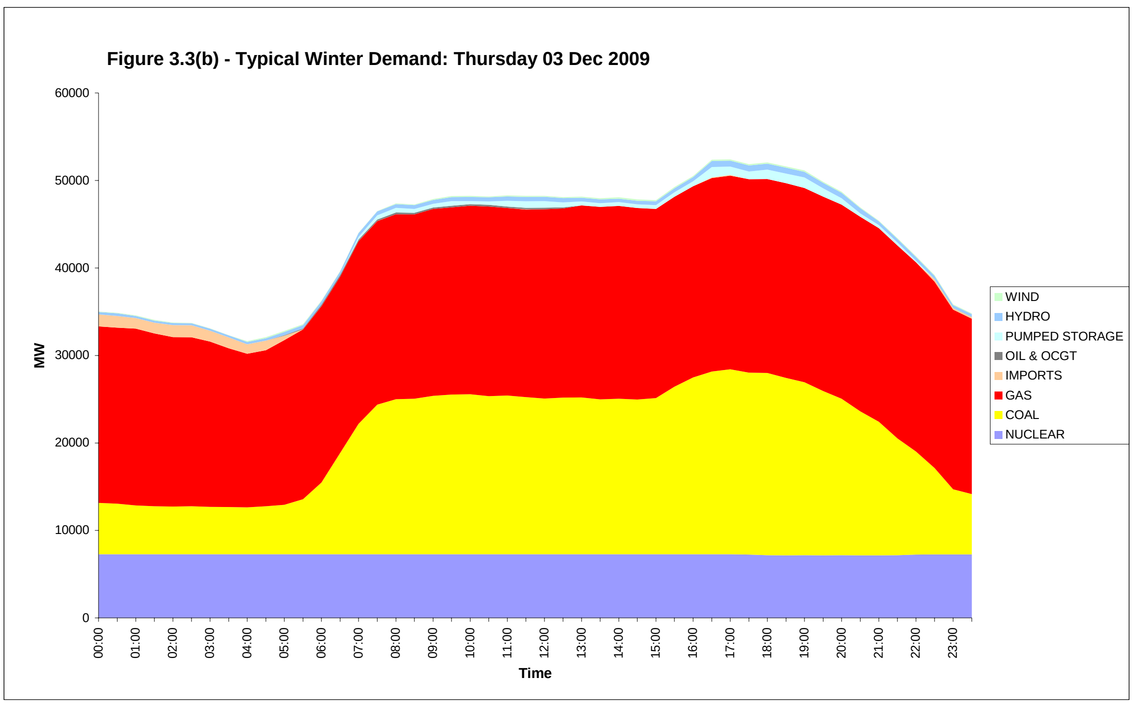


Figure 3.3(b) - Typical Winter Demand: Thursday 03 Dec 2009
MW
0
10000
20000
30000
40000
50000
60000
00:00
01:00
02:00
03:00
04:00
05:00
06:00
07:00
08:00
09:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
Time
WIND
HYDRO
PUMPED STORAGE
OIL & OCGT
IMPORTS
GAS
COAL
NUCLEAR

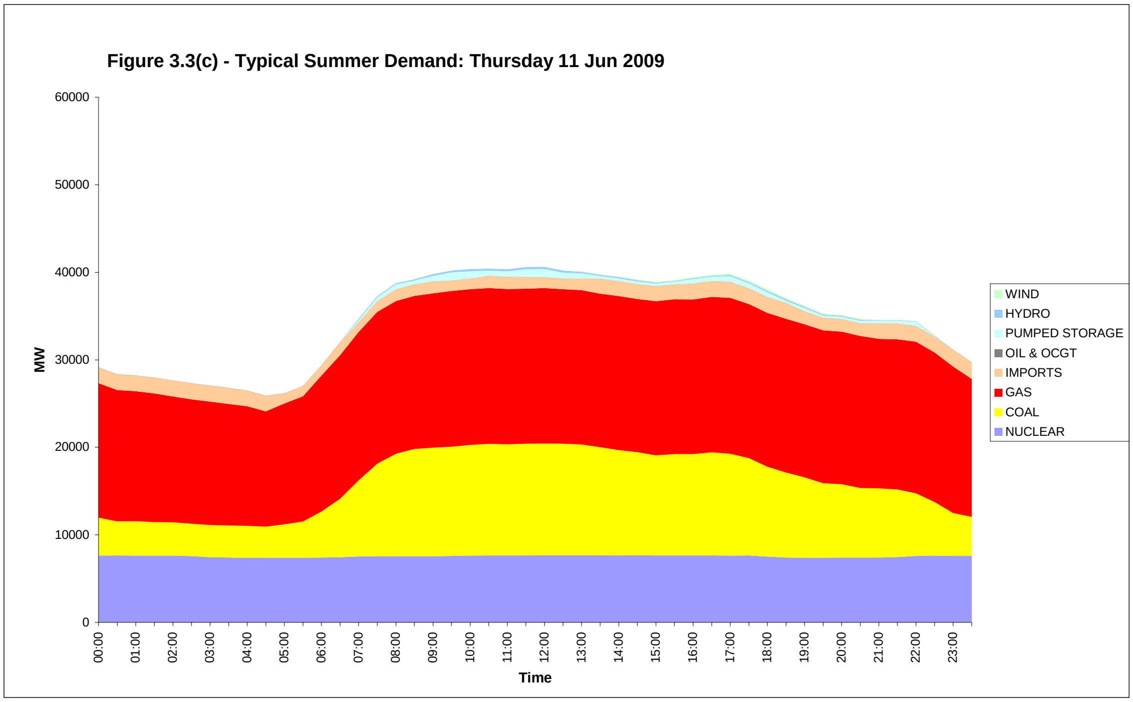


Figure 3.3(c) - Typical Summer Demand: Thursday 11 Jun 2009
60000
50000
40000
30000
20000
10000
0
MW
00:00
01:00
02:00
03:00
04:00
05:00
06:00
07:00
08:00
09:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
Time
WIND
HYDRO
PUMPED STORAGE
OIL & OCGT
IMPORTS
GAS
COAL
NUCLEAR

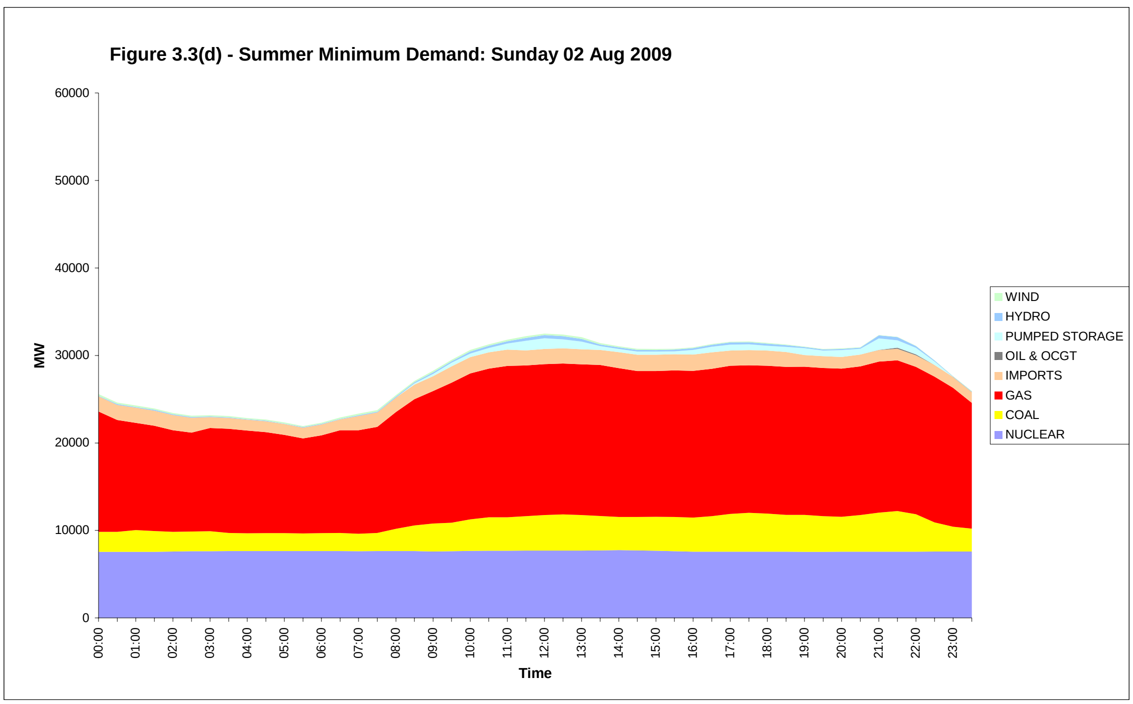


Figure 3.3(d) - Summer Minimum Demand: Sunday 02 Aug 2009
60000
50000
40000
30000
20000
10000
0
MW
00:00
01:00
02:00
03:00
04:00
05:00
06:00
07:00
08:00
09:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
Time
WIND
HYDRO
PUMPED STORAGE
OIL & OCGT
IMPORTS
GAS
COAL
NUCLEAR

The information given above is summarised in pie chart form in Figure 3.4(a), Figure 3.4(b), Figure 3.4(c) and Figure 3.4(d).

Figure 3.4(a) - Total Energy Supplied over Day of Maximum Winter Demand: Thursday 07/01/2010

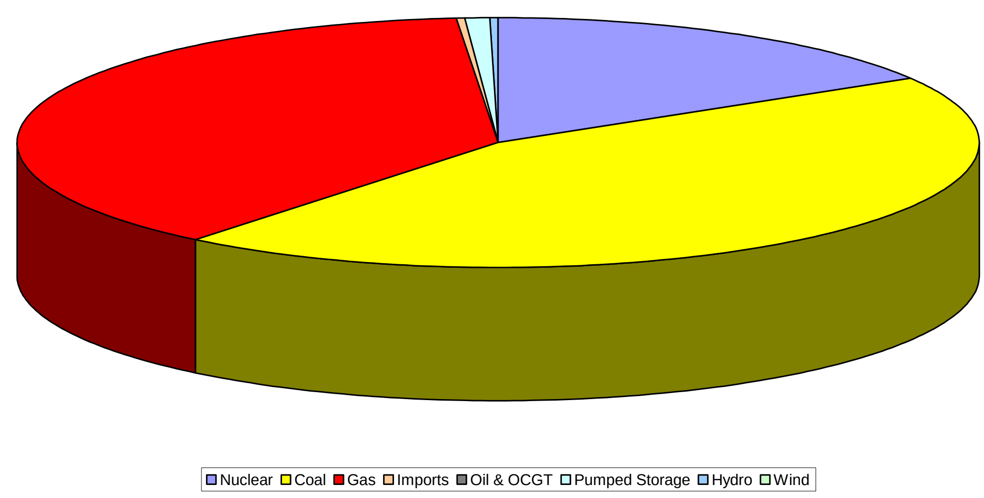
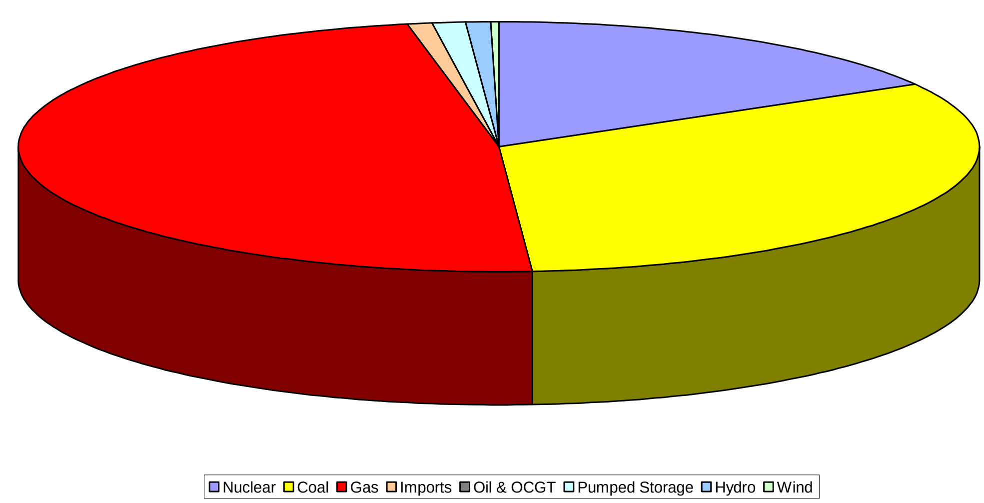
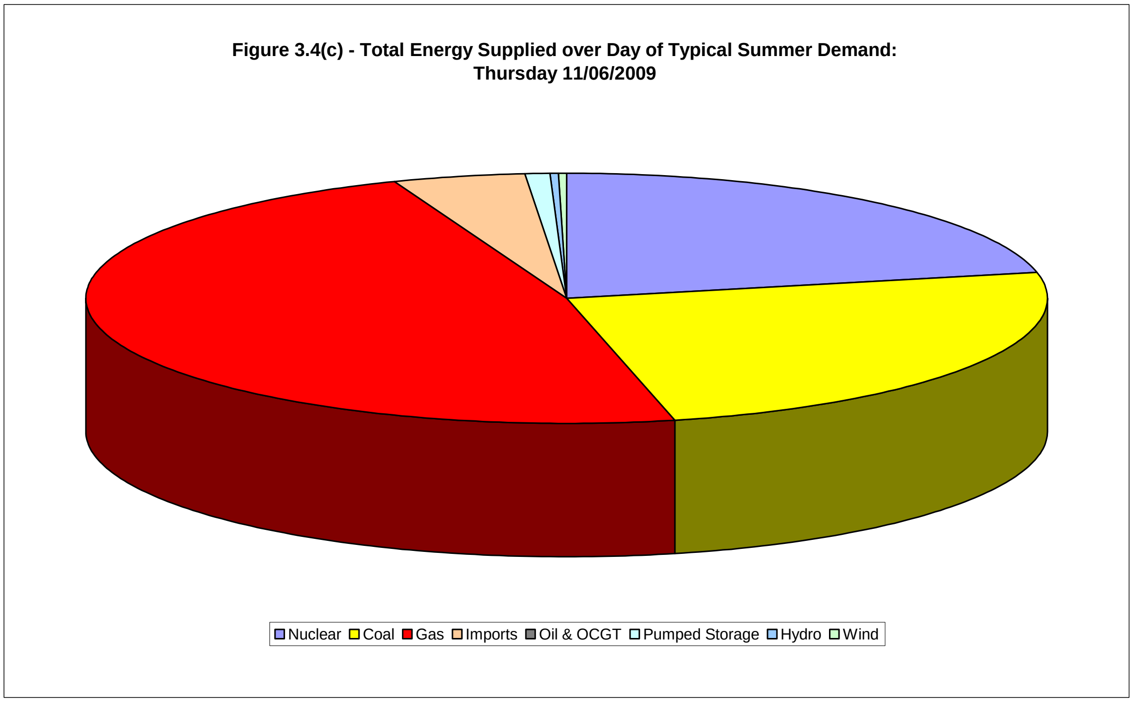
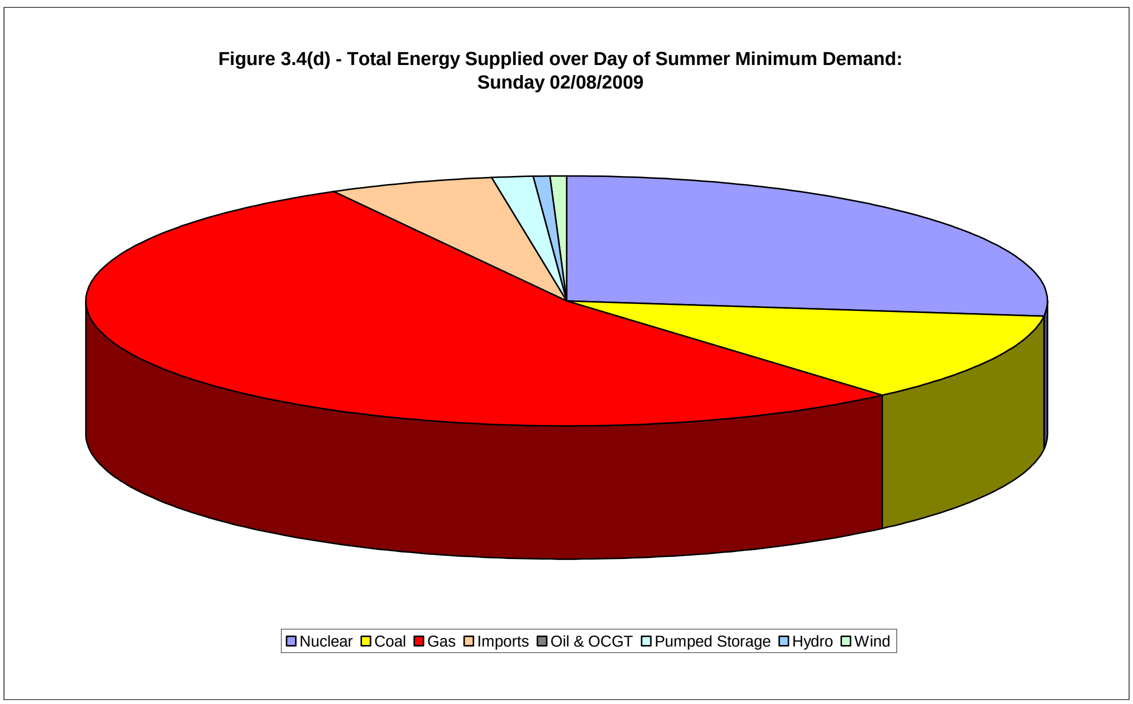


Figure 3.4(b) - Total Energy Supplied over Day of Typical Winter Demand: Thursday 03/12/2009







Generation Disposition

Figure A.1.1 in 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 the data freeze date of 31 December 2009. 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 3.8) but Large power stations with decommissioned Generating Units are shown (see Table 3.9). 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. These topics are discussed further in Chapter 7 (Transmission System Performance), Chapter 8 (Transmission System Capability) and Chapter 9 (Opportunities), which present the results of the main system analysis undertaken for this statement.

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 Chapter 6 (The Transmission System). For consistency and ease of explanation, the generation dispositions described in the following paragraphs are also presented on a similar zonal basis.

Table 3.11 shows the changes in generation capacity by plant type from 2009/10 to 2016/17. The table details the capacity changes on the basis of the SYS Study Zone Number described in Chapter 6 (The Transmission System) and referred to in Table 6.2.

It is the generation actually used in meeting the demand on the day, which determines the power flows at any given time. The 'Generation Ranking Order', which is explained in Chapter 7 (Transmission System Performance), is used to determine which generation is operated for the study purposes of this Statement.

Additional information on generation location is given in Table 3.12 and Table 3.13, which show the location of generation on the basis of SYS Study Zone and plant type for the years 2009/10 and 2016/17 respectively.

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 Chapter 7 under "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 National Electricity transmission system. In essence, TEC reflects the maximum power the user can export across the National Electricity transmission system away from the connection site. TEC is defined on a station basis only and cannot exceed station CEC. In the 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 National Electricity 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 National Electricity 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 "National Electricity Transmission System Demand".
- TEC is the main generation capacity term/value used in the NETS 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 National Electricity 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 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.

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	Unclassified	Unclassified
Small	Less than 50	Less than 30	Less than 10

Notwithstanding the fact that the 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.

Table 10.2 in 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 connection to the National Electricity transmission system as well as for use of the national electricity 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 national electricity 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 national electricity transmission system and, in consequence, does not pay connection charges relating to the national electricity transmission system. The User does however use the national electricity 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 national electricity transmission system of which there are none. However, a BEGA power station does have a TEC for the purpose of use of the national electricity 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 National Electricity 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 National Electricity transmission system and in consequence does not pay connection charges relating to the National Electricity transmission system. Nor does the power station ‘directly’ use the National Electricity 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 national electricity transmission system is provided through arrangements with National Grid, acting as NETSO, under the Connection and Use of System Code (CUSC). The CUSC sets out the contractual framework for connection to, and use of, the national electricity 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 national electricity transmission system are routed through National Grid as NETSO. 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 national electricity transmission system is currently under review, details of which can be found in chapter 9.

Table 3.2 - Generation Projects Under Construction					
Licensee	**Plant Type**	**Power Station**	**New Capacity (MW)**	**Year**	**SYS Study Zone**
NGET	CCGT	Severn Power Stage 1	425	2009	Z13
NGET	CCGT	Staythorpe C (Stage 1)	0	2009	Z8
NGET	CCGT	Staythorpe C (Stage 2)	425	2009	Z10
NGET	CCGT	Staythorpe C (Stage 3)	850	2009	Z10
NGET	CCGT	Severn Power Stage 2	425	2010	Z13
NGET	CCGT	Staythorpe C (Stage 4)	425	2010	Z10
NGET	CCGT	Grain (Stage 2)	860	2010	Z15
NGET	CCGT	Grain (Stage 3)	430	2011	Z15
NGET	CCGT	West Burton B - Stage 1	435	2011	Z14
NGET	CCGT	West Burton B - Stage 2	435	2011	Z8
NGET	CCGT	West Burton B - Stage 3	435	2011	Z10
NGET	CHP	Immingham Stage 3	0	2010	Z8
NGET	Interconnector	Britned Stage 1	0	2009	Z15
NGET	Interconnector	Britned Stage 3	400	2010	Z15
NGET	Interconnector	Britned Stage 2	800	2010	Z15
NGET	Wind Offshore	Greater Gabbard Offshore Wind Farm	500	2009	Z12
NGET	Wind Offshore	Thanet Offshore Windfarm	300	2009	Z10
NGET	Wind Offshore	Walney I Offshore Windfarm	31	2010	Z8
SHETL	Wind Onshore	Millennium Wind (Stage 2), Ceannacroc	10	2008	Z1
SHETL	Wind Onshore	Fairburn Wind Farm	40	2009	Z1
SHETL	Wind Onshore	Gordonbush Wind	70	2009	Z1
SHETL	Wind Onshore	An Suidhe Wind Farm, Argyll (SRO)	20.7	2010	Z3
SHETL	Wind Onshore	Beinn an Tuirc 2	38	2010	Z3
SHETL	Wind Onshore	Drummuir Wind	48.3	2011	Z1
SHETL	Wind Onshore	AChruach Wind Farm	49.9	2013	Z1
SPT	Wind Onshore	Toddleburn Wind Farm	36	2009	Z6
SPT	Wind Onshore	Crystal Rig 2	138	2009	Z6
SPT	Wind Onshore	Clyde Wind Farm (Scotland) Ltd	519	2010	Z6

Table 3.3 - Generation Projects with Consents Granted					
Licensee	**Plant Type**	**Power Station**	**New Capacity (MW)**	**Year**	**SYS Study Zone**
NGET	CCGT	Pembroke (Stage 1)	800	2011	Z9
NGET	CCGT	Pembroke (Stage 2)	800	2011	Z9
NGET	CCGT	Drakelow D	1320	2012	Z11
NGET	CCGT	Partington Power Station	430	2012	Z16
NGET	CCGT	Partington Power Station	430	2012	Z15
NGET	CCGT	Pembroke (Stage 3)	400	2012	Z13
NGET	CCGT	Barking Power Station C	470	2013	Z14
NGET	CCGT	Brine Field	1020	2013	Z7
NGET	CCGT	Kings Lynn B	981	2014	Z8
NGET	IGCC with CCS	Hatfield Power Station	800	2013	Z8
NGET	Large Unit Coal	Blyth	0	2050	Z7
NGET	Wind Offshore	Lincs Offshore Wind Farm	250	2010	Z15
NGET	Wind Offshore	Ormonde (Stage 2)	51	2010	Z12

Table 3.3 - Generation Projects with Consents Granted					
Licensee	**Plant Type**	**Power Station**	**New Capacity (MW)**	**Year**	**SYS Study Zone**
NGET	Wind Offshore	Sheringham Shoal Offshore Windfarm	315	2010	Z10
NGET	Wind Offshore	Ormonde (Stage 1)	98	2010	Z12
NGET	Wind Offshore	Walney II Offshore windfarm	183	2011	Z9
NGET	Wind Offshore	London Array Stage 1	630	2012	Z9
NGET	Wind Offshore	West of Duddon Sands	333	2013	Z9
NGET	Wind Offshore	London Array Stage 2	370	2014	Z9
NGET	Woodchip	Port Talbot Woodchip Power Station	350	2013	Z13
SHETL	Wind Onshore	Millennium Wind (Stage 1), Ceannacroc	40	2007	Z1
SHETL	Wind Onshore	Lairg - Achany Wind Farm	50	2009	Z1
SHETL	Wind Onshore	Millennium Wind (Stage 3), Ceannacroc	15	2009	Z1
SHETL	Wind Onshore	Strath Brora Wind, Brora	0	2009	Z1
SHETL	Wind Onshore	Drumderg Wind Farm	32	2009	Z4
SHETL	Wind Onshore	Tullo Wind Farm Laurencekirk	17	2009	Z4
SHETL	Wind Onshore	Tullo Wind Farm Laurencekirk	0	2009	Z4
SHETL	Wind Onshore	Strath Brora Wind, Brora	67	2009	Z1
SHETL	Wind Onshore	Carraig Gheal Wind Farm	60	2010	Z3
SHETL	Wind Onshore	Griffin Windfarm, near Aberfeldy	204	2010	Z4
SHETL	Wind Onshore	Mid Hill Wind	75	2012	Z2
SHETL	Wind Onshore	Causeymire Phase 2	6.9	2013	Z1
SHETL	Wind Onshore	Berry Burn Wind Farm	72.5	2013	Z1
SHETL	Wind Onshore	Camster	62.5	2014	Z1
SHETL	Wind Onshore	Novar 2 Wind Farm Alness	32	2014	Z1
SHETL	Wind Onshore	Pentland Road	13.8	2016	Z1
SHETL	Wind Onshore	Rosehall	25	2018	Z1
SHETL	Wind Onshore	Lochluichart	66	2018	Z1
SPT	Biomass	Rothes Bio-Plant	52	2011	Z5
SPT	Wind Onshore	Longpark	38	2009	Z6
SPT	Wind Onshore	Aikengall	48	2009	Z6
SPT	Wind Onshore	Arecleoch	150	2010	Z6
SPT	Wind Onshore	Mark Hill Wind Farm	56	2010	Z6
SPT	Wind Onshore	Drone Hill	37.8	2011	Z6
SPT	Wind Onshore	Harestanes	140	2011	Z6
SPT	Wind Onshore	Tormywheel	32.4	2011	Z6
SPT	Wind Onshore	Whiteside Hill	27	2013	Z6
SPT	Wind Onshore	Brockloch Rig Wind Farm	60	2013	Z6
SPT	Wind Onshore	Whitelee Extension	218.5	2018	Z6

Table 3.4 - Generation Commissioning Date Assumptions						
Licensee	**Commissioning Year**	**Station Name**	**Plant Type**	**TEC (MW)**	**Contract Date**	**Project Status**
		none				

Table 3.5 - Changes in Power Station Capacity (TEC (MW)), 2005/06 to 2009/10

Power Station	2005	2006	2007	2008	2009	Licensee	Plant Type	SYS Study Zone
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	14.3					SHETL	Onshore Wind	Z2
Paul's Hill Wind	14					SHETL	Onshore Wind	Z1
Dummuies Windfarm, Insch	10.4					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			75.9			SPT	Onshore Wind	Z6
Kilbraur (Strath Brora) Wind Farm Stage 1			47.5			SHETL	Onshore Wind	Z1
Stevens Croft			45			SPT	Biomass	Z6
Millenium Wind, Ceannacroc Stage 1			40			SHETL	Onshore Wind	Z1
Minsca			37.5			SPT	Onshore Wind	Z6
Dalswinton			30			SPT	Onshore Wind	Z6
Ben Aketil Wind			21			SHETL	Onshore Wind	Z1
Ben Aketil Wind (Add. Cap.)			7			SHETL	Onshore Wind	Z1
Dungeness A			-440			NGET	Nuclear Magnox	Z15
Sizewell A			-458			NGET	Nuclear Magnox	Z12
Langage				905		NGET	CCGT	Z17
Marchwood				900		NGET	CCGT	Z16
Immingham Stage 2				601		NGET	CHP	Z8
Whitelee Stage 2				218.5		SPT	Onshore Wind	Z6
Glendoe, Fort Augustus				100		SHETL	Hydro	Z1
Millenium Wind, Ceannacroc Stage 2				10		SHETL	Onshore Wind	Z1
Staythorpe C (Stage 3)					850	NGET	CCGT	Z10
Greater Gabbard Offshore Wind Farm					500	NGET	Wind Offshore	Z12

Table 3.5 - Changes in Power Station Capacity (TEC (MW)), 2005/06 to 2009/10								
Power Station	**2005**	**2006**	**2007**	**2008**	**2009**	**Licensee**	**Plant Type**	**SYS Study Zone**
Severn Power Stage 1					425	NGET	CCGT	Z13
Staythorpe C (Stage 2)					425	NGET	CCGT	Z10
Whitelee Stage 3					104	SPT	Wind Onshore	Z6
Thanet Offshore Windfarm					300	NGET	Wind Offshore	Z10
Crystal Rig 2					138	SPT	Wind Onshore	Z6
Gordonbush Wind					70	SHETL	Wind Onshore	Z1
Kilbraur (Strath Brora) Wind Farm Stage 2					19.5	SHETL	Wind Onshore	Z1
Lairg - Achany Wind Farm					50	SHETL	Wind Onshore	Z1
Aikengall					48	SPT	Wind Onshore	Z6
Edinbane Wind, Skye					41.4	SHETL	Wind Onshore	Z1
Fairburn Wind Farm					40	SHETL	Wind Onshore	Z1
Longpark					38	SPT	Wind Onshore	Z6
Toddleburn Wind Farm					36	SPT	Wind Onshore	Z6
Drumderg Wind Farm					32	SHETL	Wind Onshore	Z4
Dunlaw Extension					29.8	SPT	Wind Onshore	Z5
Caledonian Paper Mill					23.2	SPT	CCGT	Z5
Ardkinglas					19.3	SHETL	Wind Onshore	Z3
Tullo Wind Farm Laurencekirk					17	SHETL	Wind Onshore	Z4
Millennium Wind (Stage 3), Ceannacroc					15	SHETL	Wind Onshore	Z1
Britned Stage 1					0	NGET	Interconnector	Z15
Staythorpe C (Stage 1)					0	NGET	CCGT	Z8
Annual Total (MW)	**415**	**79**	**-582**	**2735**	**3231**			
Cumulative Total (MW)	**415**	**494**	**-88**	**2646**	**5877**			

Table 3.6 - New Power Station Capacity (TEC (MW)), 2010/11 to 2016/17

Power Station	2010	2011	2012	2013	2014	2015	2016	Licensee	Plant Type	SYS Study Zone	Under Construction	Consents
Grain (Stage 2)	860							NGET	CCGT	Z15	Yes	Yes
Britned Stage 2	800							NGET	Interconnector	Z15	Yes	Yes
Clyde Wind Farm (Scotland) Ltd	519							SPT	Wind Onshore	Z6	Yes	Yes
Severn Power Stage 2	425							NGET	CCGT	Z13	Yes	Yes
Staythorpe C (Stage 4)	425							NGET	CCGT	Z10	Yes	Yes
Britned Stage 3	400							NGET	Interconnector	Z15	Yes	Yes
Sheringham Shoal Offshore Windfarm	315							NGET	Wind Offshore	Z12		Yes
Lincs Offshore Wind Farm	250							NGET	Wind Offshore	Z12		Yes
Griffin Windfarm, near Aberfeldy	204							SHETL	Wind Onshore	Z4		Yes
Arecleoch	150							SPT	Wind Onshore	Z6		Yes
Ormonde (Stage 1)	98							NGET	Wind Offshore	Z9		Yes
Carraig Gheal Wind Farm	60							SHETL	Wind Onshore	Z3		Yes
Mark Hill Wind Farm	56							SPT	Wind Onshore	Z6		Yes
Ormonde (Stage 2)	51							NGET	Wind Offshore	Z9		Yes
Wilton Stage 2	39							NGET	CCGT	Z8		
Beinn an Tuirc 2	38							SHETL	Wind Onshore	Z3	Yes	Yes
Walney I Offshore Windfarm	31							NGET	Wind Offshore	Z9	Yes	Yes
Ballindalloch Muir	20.8							SPT	Wind Onshore	Z6		
An Suidhe Wind Farm, Argyll (SRO)	20.7							SHETL	Wind Onshore	Z3	Yes	Yes
Kingsburn Wind Farm	20							SPT	Wind Onshore	Z6		
Dummuies Wind Farm Stage 2	12.3							SHETL	Wind Onshore	Z1		
Fasnakyle G4	7.5							SHETL	Hydro	Z1		
Immingham Stage 3	0							NGET	CHP	Z8	Yes	Yes
Pembroke (Stage 1)		800						NGET	CCGT	Z13		Yes
Pembroke (Stage 2)		800						NGET	CCGT	Z13		Yes
East-West Interconnector		500						NGET	Interconnector	Z9		
Docking Shoal Wind Farm		500						NGET	Wind Offshore	Z12		
West Burton B - Stage 1		435						NGET	CCGT	Z10	Yes	Yes

Table 3.6 - New Power Station Capacity (TEC (MW)), 2010/11 to 2016/17

Power Station	2010	2011	2012	2013	2014	2015	2016	Licensee	Plant Type	SYS Study Zone	Under Construction	Consents
West Burton B - Stage 2		435						NGET	CCGT	Z10	Yes	Yes
West Burton B - Stage 3		435						NGET	CCGT	Z10	Yes	Yes
Grain (Stage 3)		430						NGET	CCGT	Z15	Yes	Yes
Gwynt Y Mor Offshore Wind Farm - Stage 1		294						NGET	Wind Offshore	Z9		
Walney II Offshore windfarm		183						NGET	Wind Offshore	Z9		Yes
Harestanes		140						SPT	Wind Onshore	Z6		Yes
Earlshaugh Wind Farm		108						SPT	Wind Onshore	Z6		
Waterhead Moor		72						SPT	Wind Onshore	Z6		
Ewe Hill		66						SPT	Wind Onshore	Z6		
Harrows Law		55						SPT	Wind Onshore	Z6		
Rothes Bio-Plant		52						SPT	Biomass	Z5		Yes
Drummuir Wind		48.3						SHETL	Wind Onshore	Z1	Yes	Yes
Drone Hill		37.8						SPT	Wind Onshore	Z6		Yes
Tormywheel		32.4						SPT	Wind Onshore	Z6		Yes
Barmoor		30						SPT	Wind Onshore	Z6		
Drakelow D			1320					NGET	CCGT	Z11		Yes
Partington Power Station			860					NGET	CCGT	Z9		Yes
London Array Stage 1			630					NGET	Wind Offshore	Z15		Yes
Pembroke (Stage 3)			400					NGET	CCGT	Z13		Yes
Kyle Wind Farm			300					SPT	Wind Onshore	Z6		
Tees Renewable Energy Plant			299					NGET	Biomass	Z7		
Rhigos			299					NGET	Wind Onshore	Z13		
Gwynt Y Mor Offshore Wind Farm - Stage 2			294					NGET	Wind Offshore	Z9		
Drax Renewable Power Station			290					NGET	Biomass	Z8		
Fallago			144					SPT	Wind Onshore	Z6		
Hearthstanes B Wind Farm			81					SPT	Wind Onshore	Z6		
Neilston			80					SPT	Wind Onshore	Z6		
Mid Hill Wind			75					SHETL	Wind Onshore	Z2		Yes

Table 3.6 - New Power Station Capacity (TEC (MW)), 2010/11 to 2016/17

Power Station	2010	2011	2012	2013	2014	2015	2016	Licensee	Plant Type	SYS Study Zone	Under Construction	Consents
Dersalloch			69					SPT	Wind Onshore	Z6		
Newfield Wind Farm			60					SPT	Wind Onshore	Z6		
Andershaw			45					SPT	Wind Onshore	Z6		
Auchencorth			33					SPT	Wind Onshore	Z6		
Brine Field				1020				NGET	CCGT	Z7		Yes
Hatfield Power Station				800				NGET	IGCC with CCS	Z8		Yes
Race Bank Wind Farm				500				NGET	Wind Offshore	Z12		
Barking Power Station C				470				NGET	CCGT	Z14		Yes
South Holland Power Station - Stage 1				450				NGET	CCGT	Z10		
Abernedd Power Station Stage 1				435				NGET	CCGT	Z13		
Port Talbot Woodchip Power Station				350				NGET	Woodchip	Z13		Yes
West of Duddon Sands				333				NGET	Wind Offshore	Z9		Yes
Strathy North & South Wind				226				SHETL	Wind Onshore	Z1		
Humber Gateway Offshore Windfarm				220				NGET	Wind Offshore	Z7		
Bristol				165				NGET	Biomass	Z13		
Gwynt Y Mor Offshore Wind Farm - Stage 3				147				NGET	Wind Offshore	Z9		
Parc (South Lochs) Wind, Lewis				94				SHETL	Wind Onshore	Z1		
Afton				77				SPT	Wind Onshore	Z6		
Berry Burn Wind Farm				72.5				SHETL	Wind Onshore	Z1		Yes
Ulzieside				69				SPT	Wind Onshore	Z6		
Pencloe				63				SPT	Wind Onshore	Z6		
Brockloch Rig Wind Farm				60				SPT	Wind Onshore	Z6		Yes
Shira Wind Farm				52				SHETL	Wind Onshore	Z5		
AChruach Wind Farm				49.9				SHETL	Wind Onshore	Z1	Yes	Yes
Stacain Wind Farm				42.5				SHETL	Wind Onshore	Z5		
Black Craig 40MW				40				SHETL	Wind Onshore	Z4		
Tomatin Windfarm				30				SHETL	Wind Onshore	Z1		

Table 3.6 - New Power Station Capacity (TEC (MW)), 2010/11 to 2016/17												
Power Station	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**Licensee**	**Plant Type**	**SYS Study Zone**	**Under Construction**	**Consents**
Whiteside Hill				27				SPT	Wind Onshore	Z6		Yes
Carscreugh				21.25				SPT	Wind Onshore	Z6		
Causeymire Phase 2				6.9				SHETL	Wind Onshore	Z1		Yes
Atlantic Array					1512			NGET	Wind Offshore	Z17		
Kings Lynn B					981			NGET	CCGT	Z12		Yes
Wyre Power					950			NGET	CCGT	Z9		
Thames Haven Power Station					840			NGET	CCGT	Z15		
South Holland Power Station - Stage 2					390			NGET	CCGT	Z10		
London Array Stage 2					370			NGET	Wind Offshore	Z15		Yes
Eishken Estate, Isle of Lewis					300			SHETL	Wind Onshore	Z1		
Port of Tyne Renewable Power Station					290			NGET	Biomass	Z7		
Immingham Renewable Power Station					290			NGET	Biomass	Z8		
North Nesting Wind, Shetland					250			SHETL	Wind Onshore	Z2		
Westermost Rough Offshore windfarm					175			NGET	Wind Offshore	Z9		
Clashindarroch Wind, Huntly					112.7			SHETL	Wind Onshore	Z2		
Blackcraig Wind Farm					71.3			SPT	Wind Onshore	Z6		
Margree					70			SPT	Wind Onshore	Z6		
Camster					62.5			SHETL	Wind Onshore	Z1		Yes
Calliacher Wind Farm					62.1			SHETL	Wind Onshore	Z4		
Aultmore Wind Farm					60			SHETL	Wind Onshore	Z1		
Baillie and Bardnaheigh Wind Farm					57			SHETL	Wind Onshore	Z1		
Dunbeath Wind farm					55			SHETL	Wind Onshore	Z1		
Montreathmont Moor Wind Angus					40			SHETL	Wind Onshore	Z4		
Novar 2 Wind Farm Alness					32			SHETL	Wind Onshore	Z1		Yes
Stroupster Wind Farm near Wick Caithness					31.5			SHETL	Wind Onshore	Z1		
Dunoon Wind Farm					20			SHETL	Wind Onshore	Z5		

Table 3.6 - New Power Station Capacity (TEC (MW)), 2010/11 to 2016/17												
Power Station	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**Licensee**	**Plant Type**	**SYS Study Zone**	**Under Construction**	**Consents**
Carrington II Power Station						1520		NGET	CCGT	Z9		
Centrum Power						960		NGET	CCGT	Z11		
Greater Gabbard Wind Farm Extension						500		NGET	Wind Offshore	Z12		
Llanbrynmair South						96.6		NGET	Wind Onshore	Z9		
Kingsnorth Stage 2							1966	NGET	Large Unit Coal	Z15		
Dungeness C							1650	NGET	Nuclear EPR	Z15		
Bradwell B							1650	NGET	Nuclear EPR	Z15		
Tilbury Stage 2							1600	NGET	Large Unit Coal	Z15		
Thorpe Marsh							960	NGET	CCGT	Z8		
Abernedd Power Station Stage 2							435	NGET	CCGT	Z13		
Carnedd Wen Wind Farm							184	NGET	Wind Onshore	Z9		
Pentland Road							13.8	SHETL	Wind Onshore	Z1		Yes
Annual Total (MW)	**4802**	**5454**	**5279**	**5821**	**7022**	**3077**	**8459**					
Cumulative Total (MW)	**4802**	**10256**	**15535**	**21356**	**28378**	**31455**	**39913**					

Table 3.7 - Overview of New Capacity, 2010/11 to 2016/17								
Background	**Plant Type**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Existing	CCGT	39	39	39	39	39	39	39
Existing	Hydro	8	8	8	8	8	8	8
Existing	Wind Onshore	12	12	12	12	12	12	12
Total (1)		**59**	**59**	**59**	**59**	**59**	**59**	**59**
Under Construction	CCGT	1710	3445	3445	3445	3445	3445	3445
Under Construction	CHP	0	0	0	0	0	0	0
Under Construction	Interconnector	1200	1200	1200	1200	1200	1200	1200
Under Construction	Wind Offshore	31	31	31	31	31	31	31
Under Construction	Wind Onshore	578	626	626	676	676	676	676
Under Construction	Biomass	0	52	52	52	52	52	52
Total (2)		**3519**	**5354**	**5354**	**5404**	**5404**	**5404**	**5404**
Total (1+2)		**3578**	**5413**	**5413**	**5463**	**5463**	**5463**	**5463**
With Consents	CCGT	0	1600	4180	5670	6651	6651	6651
With Consents	IGCC with CCS	0	0	0	800	800	800	800
With Consents	Wind Offshore	714	897	1527	1860	2230	2230	2230
With Consents	Wind Onshore	470	680	755	922	1016	1016	1030
With Consents	Woodchip	0	0	0	350	350	350	350
Total (3)		**1184**	**3177**	**6462**	**9602**	**11047**	**11047**	**11061**
Total (1+2+3)		**4762**	**8590**	**11875**	**15064**	**16510**	**16510**	**16524**
Without Consents	Biomass	0	0	589	754	1334	1334	1334
Without Consents	CCGT	0	0	0	885	3065	5545	6940
Without Consents	Interconnector	0	500	500	500	500	500	500
Without Consents	Large Unit Coal	0	0	0	0	0	0	3566
Without Consents	Nuclear EPR	0	0	0	0	0	0	3300
Without Consents	Wind Offshore	0	794	1088	1955	3642	4142	4142
Without Consents	Wind Onshore	41	372	1483	2198	3327	3424	3608
Total (4)		**41**	**1666**	**3660**	**6292**	**11868**	**14945**	**23390**
Total (1+2+3+4)		**4802**	**10256**	**15535**	**21356**	**28378**	**31455**	**39913**

Table 3.8 - Generation Disconnections from 2010/11 to 2016/17 inclusive

Licensee	Closure Year	Plant Type	Station Name	Set(s) Disconnected	Capacity (MW)	Commissioning Year
NGET	2011	Nuclear Magnox	Oldbury	1, 2	470	1967-68
NGET	2011	Nuclear Magnox	Wylfa	1, 2, 3, 4	980	1971
SPT	2016	Medium Unit Coal	Cockenzie	1, 2, 3, 4	1102	
NGET	2016	Large Unit Coal	Didcot A	1, 2, 3, 4	2109	1972-75
NGET	2016	Large Unit Coal	Didcot A	G1, G2, G3, G4	100	1968-70
NGET	2016	Large Unit Coal + AGT	Ferrybridge C	1, 2, G5, G6	993	1966-68
NGET	2016	Large Unit Coal + AGT	Ironbridge	1, 2, G1, G2	964	1970
NGET	2016	Large Unit Coal + AGT	Kingsnorth	1, 2, 3, 4, G1, G4	1966	1967-73
NGET	2016	Medium Unit Coal + AGT	Tilbury	7, 8, 9, 10, G7, G8, G9, G10	1131	1965-72
NGET	2016	Oil	Fawley	1, 3, G1, G2, G3, G4	1036	1969-70
NGET	2016	Oil	Grain	1, 2, 3, 4, G1, G2, G3, G4	1355	1978-84
NGET	2016	Oil	Littlebrook	1, 2, 3, G1, G2, G3	1245	1980-84
				Total	**13451**	

Table 3.9 - Unavailable Generating Units						
Licensee	**Year**	**Plant Type**	**Station Name**	**Unit(s)**	**Capacity (MW)**	**SYS Study Zone**
NGET	1991	OCGT	Cottam	G2, G4	50	Z10
NGET	1991	OCGT	Ferrybridge C	G6, G7	34	Z8
NGET	1991	OCGT	Fiddlers Ferry	G1, G4	34	Z9
NGET	1991	OCGT	Kingsnorth	G2A, G3A	44	Z15
NGET	1991	OCGT	Ratcliffe on Soar	G1, G3	34	Z11
NGET	1994	OCGT	Cottam	G1, G3	50	Z10
NGET	1994	OCGT	Drax	G7	25	Z8
NGET	1994	OCGT	Eggborough	G6, G7	34	Z8
NGET	1994	Oil	Grain	2	675	Z15
NGET	1994	OCGT	Grain	G2A, G3A, G5A	87	Z15
NGET	1994	OCGT	Ironbridge B	G1, G2	34	Z11
NGET	1994	OCGT	Tilbury B	G7A	17	Z15
NGET	1994	OCGT	West Burton	G2, G3	40	Z10
NGET	1995	OCGT	Fawley	G2, G4	34	Z16
NGET	1995	Oil	Littlebrook D	3	685	Z14
NGET	1998	Oil	Grain	3	675	Z15
NGET	1998	OCGT	Tilbury B	G10A	17	Z15
NGET	1998	Medium Unit Coal	Tilbury B	7	350	Z15
				Total	**2919**	

Table 3.10 - 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	Export	500	500	2011
SPT	Northern Ireland	Export	80	500	Existing

Table 3.11 - Growth in Generation Capacity (MW) by Plant Type and SYS Study Zone, 2009/10 to 2016/17

Plant Type	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	Z11	Z12	Z13	Z14	Z15	Z16	Z17	Total
Biomass					52		589	580					165					**1386**
Biopower																		**0**
CCGT							1020	999	3330	2570	2280	981	3295	470	2130			**17075**
CHP																		**0**
Clean Coal																		**0**
Hydro	8																	**8**
IGCC with CCS								800										**800**
Interconnector									500						1200			**1700**
Large Unit Coal													-2109		3566			**1457**
Large Unit Coal + AGT								-993			-964				-1966			**-3923**
Medium Unit Coal						-1102												**-1102**
Medium Unit Coal + AGT															-1131			**-1131**
Nuclear AGR																		**0**
Nuclear APR																		**0**
Nuclear EPR															3300			**3300**
Nuclear Magnox									-980				-470					**-1450**
Nuclear PWR																		**0**
OCGT																		**0**
Oil + AGT														-1245	-1355	-1036		**-3636**
Pumped Storage																		**0**
Small Unit Coal																		**0**
Tidal																		**0**
Wave																		**0**
Wind Offshore							220		1606			2065			1000		1512	**6403**
Wind Onshore	1141	438	119	346	115	2578			281				299					**5315**
Woodchip													350					**350**
Total (MW)	**1149**	**438**	**119**	**346**	**167**	**1476**	**1829**	**1386**	**4737**	**2570**	**1316**	**3046**	**1530**	**-775**	**6744**	**-1036**	**1512**	**26552**

Table 3.12 - 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**
Biopower																		**0**
CCGT		1524			23		1875	5005	2924	2550	0	3031	4006	2123	2305	1320	905	**27591**
CHP		12				243		1218	365		228					158		**2224**
Clean Coal																		**0**
Hydro	532	11	204	350	33													**1129**
IGCC with CCS																		**0**
Interconnector						80									1988			**2068**
Large Unit Coal						2284							2109		0			**4393**
Large Unit Coal + AGT								7832	1987	3987	4003		1692		1966			**21467**
Medium Unit Coal						1102												**1102**
Medium Unit Coal + AGT															1131			**1131**
Nuclear AGR					1074	1215	1207		2406						1081		1261	**8244**
Nuclear APR																		**0**
Nuclear EPR																		**0**
Nuclear Magnox									980				470					**1450**
Nuclear PWR												1200						**1200**
OCGT													100	144		195	140	**579**
Oil + AGT														1245	1355	1036		**3636**
Pumped Storage	300					440	360		1644									**2744**
Small Unit Coal							420						363					**783**
Tidal																		**0**
Wave																		**0**
Wind Offshore												500			300			**800**
Wind Onshore	715	26	83	153	30	985												**1992**
Woodchip																		**0**
Total (MW)	**1547**	**1573**	**287**	**502**	**1160**	**6394**	**3862**	**14055**	**10306**	**6537**	**4231**	**4731**	**8740**	**3512**	**10126**	**2709**	**2306**	**82578**

Table 3.13 - Subtotals of TEC (MW) by Plant Type and SYS Study Zone, 2016/17

Plant Type	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	Z11	Z12	Z13	Z14	Z15	Z16	Z17	Total
Biomass					52	45	589	580					165					**1431**
Biopower																		**0**
CCGT		1524			23		2895	6004	6254	5120	2280	4012	7301	2593	4435	1320	905	**44666**
CHP		12				243		1218	365		228					158		**2224**
Clean Coal																		**0**
Hydro	540	11	204	350	33													**1137**
IGCC with CCS								800										**800**
Interconnector						80			500						3188			**3768**
Large Unit Coal						2284									3566			**5850**
Large Unit Coal + AGT								6839	1987	3987	3039		1692					**17544**
Medium Unit Coal																		**0**
Medium Unit Coal + AGT																		**0**
Nuclear AGR					1074	1215	1207		2406						1081		1261	**8244**
Nuclear APR																		**0**
Nuclear EPR															3300			**3300**
Nuclear Magnox																		**0**
Nuclear PWR												1200						**1200**
OCGT													100	144		195	140	**579**
Oil + AGT																		**0**
Pumped Storage	300					440	360		1644									**2744**
Small Unit Coal							420						363					**783**
Tidal																		**0**
Wave																		**0**
Wind Offshore							220		1606			2565			1300		1512	**7203**
Wind Onshore	1856	464	202	499	144	3562			281				299					**7307**
Woodchip													350					**350**
Total (MW)	**2696**	**2011**	**405**	**848**	**1326**	**7869**	**5691**	**15441**	**15043**	**9107**	**5547**	**7777**	**10270**	**2737**	**16870**	**1673**	**3818**	**109130**

Table 3.14 - Transmission Contracted Generation beyond 2016/17

Licensee	Plant Type	Power Station	Owner	New Capacity (MW)	Year	SYS Study Zone
NGET	CCGT	Damhead Creek 2 - Stage 1	ScottishPower(DCL) Limited	493	2019	Z15
NGET	CCGT	Damhead Creek 2 - Stage 2	ScottishPower(DCL) Limited	493	2022	Z15
NGET	CCGT	Seabank 3	Seabank Power Limited	824	2023	Z13
NGET	IGCC with CCS	Teesside ICCGT Power Station	Coastal Energy Limited	0	2050	Z7
NGET	Interconnector	Belgium Interconnetor	National Grid International Ltd	1000	2019	Z15
NGET	Large Unit Coal	Blyth	RWE Npower plc	0	2050	Z7
NGET	Nuclear APR	Wylfa C Stage 1	RWE Npower plc	1200	2020	Z9
NGET	Nuclear APR	Cumbria Coast (North) Power Station Stage 1	RWE Npower plc	1200	2021	Z9
NGET	Nuclear APR	Wylfa C Stage 2	RWE Npower plc	1200	2021	Z9
NGET	Nuclear APR	Cumbria Coast (North) Power Station Stage 2	RWE Npower plc	2400	2022	Z9
NGET	Nuclear APR	Wylfa C Stage 3	RWE Npower plc	1200	2022	Z9
NGET	Nuclear APR	Cumbria Coast (South) Power Station Stage 1	RWE Npower plc	1200	2023	Z9
NGET	Nuclear APR	Cumbria Coast (South) Power Station Stage 2	RWE Npower plc	1200	2024	Z9
NGET	Nuclear APR	Cumbria Coast (South) Power Station Stage 3	RWE Npower plc	1200	2025	Z9
NGET	Nuclear EPR	Wylfa B	Bow Bidco (Wylfa) Limited	1670	2017	Z9
NGET	Nuclear EPR	Hinkley Point C Stage 1	British Energy Generation Limited	1670	2017	Z17
NGET	Nuclear EPR	Hinkley Point C Stage 2	British Energy Generation limited	1670	2018	Z17
NGET	Nuclear EPR	Sizewell C (Stage 1)	British Energy Generation Limited	1670	2020	Z12
NGET	Nuclear EPR	Oldbury-on-Severn Power Station	E.ON UK plc	1600	2020	Z13
NGET	Nuclear EPR	Sizewell C (Stage 2)	British Energy Generation Limited	1670	2021	Z12
NGET	Nuclear EPR	Heysham 3	British Energy Generation Limited	1650	2022	Z9
NGET	Nuclear EPR	Oldbury C	Nuclear Decommissioning Authority	1600	2023	Z13
NGET	Nuclear EPR	Sellafield Stage 1	Nuclear Decommissioning Authority	1600	2023	Z9
NGET	Nuclear EPR	Sellafield Stage 2	Nuclear Decommissioning Authority	1600	2025	Z9
NGET	Wind Offshore	Triton Knoll Stage 1	Triton Knoll Offshore Wind Farm Limited	392	2018	Z10
NGET	Wind Offshore	Triton Knoll Stage 2	Triton Knoll Offshore Wind Farm Limited	392	2019	Z10
NGET	Wind Offshore	Triton Knoll Stage 3	Triton Knoll Offshore Wind Farm Limited	392	2020	Z10
SHETL	Hydro	Glenmoriston Hydro Group (Additional	SSE Generation Limited	6	2019	Z1

Table 3.14 - Transmission Contracted Generation beyond 2016/17						
Licensee	**Plant Type**	**Power Station**	**Owner**	**New Capacity (MW)**	**Year**	**SYS Study Zone**
		Capacity)				
SHETL	Tidal	Islay Marine Energy Park	D P Marine Energy Limited	400	2019	Z3
SHETL	Tidal	Sound of Islay Tidal	ScottishPower Renewables (UK) Limited	10	2019	Z1
SHETL	Wave	Stromness Wave Farm	CRE Energy Limited	22.5	2019	Z1
SHETL	Wind Offshore	Beatrice Wind Farm	SSE Generation Limited	1000	2019	Z1
SHETL	Wind Onshore	Lochluichart	LZN Ltd	66	2018	Z1
SHETL	Wind Onshore	Viking Wind Farm	Viking Energy Ltd	300	2018	Z2
SHETL	Wind Onshore	Spittal Hill Wind Farm	Spittal Hill Wind Farm Limited	80	2018	Z1
SHETL	Wind Onshore	Hanna Wind Farm	Wind Energy Limited	81	2018	Z1
SHETL	Wind Onshore	Rosehall	E.ON UK Renewables Developments Limited	25	2018	Z1
SHETL	Wind Onshore	Invercassley Windfarm	Airtricity Developments (Scotland) Ltd	50	2018	Z1
SHETL	Wind Onshore	Dumnaglass Wind Farm	RES UK & Ireland Limited	99	2018	Z1
SHETL	Wind Onshore	Forse Wind Farm	Wind Energy Limited	60	2018	Z1
SHETL	Wind Onshore	Cairn Uish (Phase 2)	Fred Olsen Wind 1 Limited	40	2018	Z1
SHETL	Wind Onshore	Jacksbank Wind Farm, Glenbervie	Ron Shanks Development Project Ltd	81	2019	Z1
SHETL	Wind Onshore	Tomatin Wind Farm (Additional Capacity)	Eurus Energy UK Ltd	69	2019	Z1
SHETL	Wind Onshore	Tom Nan Clach Wind Farm	Infinergy Limited	150	2019	Z2
SHETL	Wind Onshore	Tofingall Wind Farm	Gamesa Energy UK Limited	50	2019	Z1
SHETL	Wind Onshore	Aberchalder Wind Farm	Gamesa Energy UK Limited	300	2019	Z1
SHETL	Wind Onshore	Kilchattan	Wind Prospect Developments Limited	10	2019	Z1
SHETL	Wind Onshore	Braemore Windfarm Shin	Wind Prospect Development Limited	66	2019	Z1
SHETL	Wind Onshore	Hill of Fishrie Wind Farm	Novera Energy Plc	18	2019	Z1
SHETL	Wind Onshore	Gordonstown Hill Wind Farm	Gordonstown Hill Wind Farm Limited	12.5	2019	Z1
SHETL	Wind Onshore	Glen Calvie B Wind Farm, Ardgay	Wind Energy (Glencalvie) Ltd	45	2019	Z1
SHETL	Wind Onshore	Drumnafunner	Novera Energy Plc	20	2019	Z1
SHETL	Wind Onshore	Dorenell Wind Farm	Infinergy Limited	180	2019	Z1
SHETL	Wind Onshore	Corriemollie Wind Farm, Dingwall	E.ON UK Plc	22	2019	Z1
SHETL	Wind Onshore	Corrennie Windfarm	Novera Energy Plc	29.9	2019	Z2
SHETL	Wind Onshore	Cambusmore Wind Farm	Renewable Energy Systems UK Ltd	41.4	2019	Z1

Table 3.14 - Transmission Contracted Generation beyond 2016/17						
Licensee	**Plant Type**	**Power Station**	**Owner**	**New Capacity (MW)**	**Year**	**SYS Study Zone**
SHETL	Wind Onshore	Glen Calvie Wind Farm, Ardgay	Wind Energy (Glencalvie) Ltd	69	2019	Z1
SHETL	Wind Onshore	Strath Rusdale	RockBySea Limited	30	2019	Z1
SPT	Biopower	Chapelcross Biopower CHP Plant	Scottish BioPower Limited	250	2019	Z6
SPT	Biopower	Killoch Biopower CHP Plant	Scottish BioPower Limited	250	2019	Z6
SPT	Clean Coal	Hunterston 2	Ayrshire Power Limited	1600	2019	Z6
SPT	Wind Onshore	Galawhistle Wind Farm	Infinis Limited	66.7	2018	Z6
SPT	Wind Onshore	Whitelee Extension	ScottishPower Renewables (UK) Limited	218.5	2018	Z6
SPT	Wind Onshore	Blacklaw Extension	CRE Energy Limited	69	2019	Z6
SPT	Wind Onshore	Blacklaw Extension	CRE Energy Limited	0	2019	Z6
SPT	Wind Onshore	Burnhead Wind Farm	Infinis Limited	43.7	2019	Z6

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Chapter 4

Embedded and Renewable Generation

Introduction

Chapter 3 (Generation) presents information on all the sources of generation which are used to meet the ACS Peak Demand as defined in the Glossary and presented in Chapter 2 (Electricity Demand). Accordingly, Chapter 3 presents information on Large power stations (directly connected or embedded), Medium and Small power stations that are directly connected to the national electricity transmission system and directly connected External Interconnections with External Systems.

Embedded generation may be Large but is more likely to be either Medium or Small. Large embedded power stations are reported in Chapter 3 as explained above. Medium and Small embedded power stations and embedded External Interconnections with External Systems are reported in this 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 and, in so doing, also reports on non-embedded renewable sources of generation (e.g. Wind farms).

The Benefits of an Interconnected Transmission System

Superficially, it may seem reasonable to assume that growth in embedded generation could eventually lead to a position of zonal self-sufficiency rendering the national electricity transmission system redundant in whole or in part. However, this is not the case and, to understand why, it is first helpful to remind ourselves of the role of the interconnected transmission system and its history.

Until the 1930s, electricity supply in Britain was the responsibility of a multiplicity of private and municipally owned utilities, each operating largely in isolation. The Electricity (Supply) Act (1926) recognised that this was a wasteful duplication of resources. In particular, each authority had to install enough generating plant to cover the breakdown and maintenance of its generation. Once installed, it was necessary to run more plant than the expected demand to allow for possible sudden plant failure.

By interconnecting separate utilities with the high voltage transmission system, it is possible to pool both generation and demand. The interconnected transmission system not only provides for a consistent high quality of supply (e.g. in terms of frequency variations, voltage level, voltage waveforms, voltage fluctuations and harmonic levels) across the system but it also provides a number of economic and other benefits including those outlined in this chapter.

Bulk Power Transfers

A number of factors influence the decision to construct a power station at a particular location. These include fuel availability, fuel price, fuel transport costs, financing, cooling water, land availability and the level of transmission system charges. For combined heat and power (CHP) stations a local market for the heat output would also be a consideration.

It can be very difficult, particularly for large power stations, to obtain sites close to demand centres for environmental and other reasons. Similarly, some renewable energy generation technologies such as wind or wave are unlikely to be located near demand centres. The interconnected transmission system provides for the efficient bulk transfer of power from remote generation to demand centres irrespective of the actual connection voltage of the generation. Transmission of electricity at high voltage is more efficient than transfer at lower voltage due to the lower capital cost per unit transmitted and the lower losses (the 400kV and 275kV national electricity transmission system losses are approximately 1.5% of energy transmitted).

Economic Operation

The interconnected transmission system provides the main national electrical link between all participants (generation and demand) and by linking them via the transmission system it is then possible to select the cheapest generation available. Market participants can thus choose to trade with the most competitive counter party and National Grid, in its role as NETSO (National Electricity Transmission System Operator), is able to accept the most attractive 'bids' and 'offers' in the Balancing Mechanism to meet the demand, irrespective of location.

Security of Supply

Security in this context means providing the demand customer with a supply of electricity that is continuous (i.e. uninterrupted except in exceptional circumstances) and is of the required quantity and of defined quality (e.g. in terms of voltage, waveform and frequency). This means that the transmission system, and for that matter the generation and distribution systems, must be sufficiently robust to maintain supplies under conditions of plant breakdown or weather induced failures for a wide range of demand conditions.

Interruption of supply can result from insufficiency or unavailability of generation, transmission or distribution capacity. The former is a function of the electricity market. The latter is the concern of the distribution network operators. For transmission, the system is planned and operated in accordance with strict standards laid down in the Transmission Licence.

It may at first seem that security of supply is potentially at its greatest when the source of power is close to the demand it supplies. However, transmission circuits tend to be far more reliable than individual generating units. Accordingly, enhanced security is delivered by providing sufficient transmission capacity between customers and the national stock of generation. The transmission system is able to exploit the diversity between individual generation sources and demand.

Reduction in Plant Margin

In an ideal world it would simply be necessary to install generation capacity to meet the forecast maximum average cold spell (ACS) demand. In practice, additional capacity is required for security purposes to cover for one or more of the following reasons: the fact that plant becomes unavailable due either to routine maintenance or breakdown; or plant under construction may not be commissioned on time; the weather may be colder than ACS conditions; or the ACS peak demand forecast may simply be underestimated.

The integrated transmission system enables surplus generating capacity in one area to be used to cover shortfalls elsewhere on the system. The requirement for additional installed generating capacity, to provide sufficient generation security for the whole system, is therefore smaller than the sum of individual zonal requirements.

As a point of interest, before privatisation the Central Electricity Generating Board (CEGB) in England & Wales used a planning margin of 24% to provide generation security when planning the need for future generation installed capacity. Under the pre-NETA electricity "Pool" trading arrangements in England & Wales, capacity payments were paid in respect of available generation capacity. These capacity payments, which were a function of Loss of Load Probability (LOLP), were intended to provide a signal of capacity requirements. Under NETA/BETTA market forces determine the plant margin.

Reduction in Frequency Response

National Grid as NETSO has a statutory obligation to maintain frequency between certain specified limits save in exceptional circumstances (see the Electricity Supply Regulations 1989). Large deviations in frequency can lead to widespread demand disconnections and generation disruptions. System frequency is a continuously changing variable and is determined and controlled by a careful balance between demand and generation. If demand is greater than generation, frequency falls and, if generation is greater than demand, frequency rises.

With the arguable exception of pumped storage power stations, electricity, unlike other commodities, cannot be stored in significant quantities. Therefore, in order to avoid an unacceptable fall in frequency in the event of the failure of one or more sources of generation, it is necessary to have available additional generation, that can be called upon at very short notice (i.e. within seconds or minutes). This is referred to as 'frequency response'.

Without transmission interconnection, each separate system would need to carry its own frequency response. With interconnection the net response requirement is the highest of the individual system requirements to cover for the largest potential loss of power (generation) infeed, rather than the sum of them all.

Embedded Generation

Types of Embedded Generation

The output of most embedded Medium and Small power stations falls into two main categories that are not mutually exclusive, namely that generated primarily for own use, normally in the form of CHP (combined heat and power), and that generated for supply to third parties, mainly from renewable sources (e.g. wind).

A CHP plant is an installation where there is simultaneous generation of usable heat and electrical power in a single process. CHP schemes are generally fuelled by gas, coal or oil although some are also partially fuelled by fossil fuels and partially fuelled by renewable sources of energy (e.g. biofuels such as sewage gas). The latter are referred to as 'Co-firing' generating stations. CHP schemes tend to be located in close to customers (e.g. large industry) wishing to take the heat output.

Renewable generation technologies cover a range of energy sources including hydro, biofuels, wind, wave and solar. In output terms, the largest contributions currently come from biofuels, which include landfill gas, waste combustion, sewage sludge digestion and coppice wood and straw burning. UK Government figures show that in 2008, renewable sources generated 21.597GWh of electricity (5.5% of the electricity generated in the UK). This was made up of Wind (33%), Hydro (26%), Landfill Gas (22%), Biofuels (14%) and Co-firing (7%).

Further information can be found on the renewable energy statistics website:

http://www.restats.org.uk/

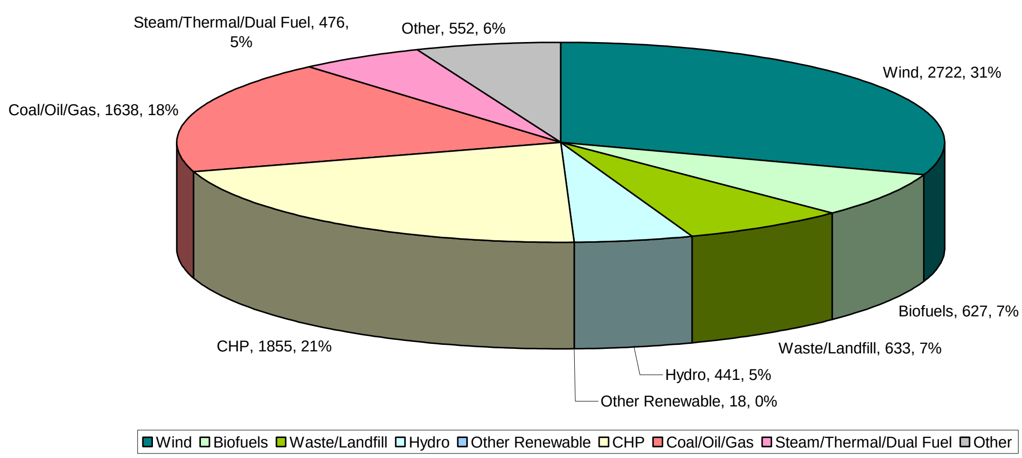
http://www.restats.org.uk/electricity.htm

Embedded Small and Medium Power Stations

Chapter 2 (Electricity Demand) considers, amongst other things, the forecast peak demand on the national electricity transmission system in average cold spell (ACS) conditions, which is based on the projections provided by the system 'Users' and by National Grid. ACS peak demand relates to the demand met by directly connected power stations, imports across directly connected External Interconnections from External Systems and embedded Large power stations, all of which are the subject of Chapter 3 (Generation).

Network operators are required under the Grid Code to net off their own allowances for the output from embedded Medium and Small power stations when submitting their forecasts of demand to be supplied at the Grid Supply Points. They are also required to net off their own allowances for any forecast imports across embedded External Interconnections from External Systems. Accordingly, the output of embedded Medium and Small power stations is taken into account when planning the development of the transmission system. However, this output is not directly seen by the transmission system operator, although its overall effect on the national electricity transmission system and its operation is.

Figure 4.1 - Main Types of Embedded Generation (MW)



In responding to previous customer surveys, many readers have requested detailed information on embedded generation to be included in the Seven Year Statement. In response to these requests, we have included Table F.3 in Appendix F, which contains a range of information on Small and Medium power stations embedded within distribution networks. The information in this table is based on information originally provided by the relevant distribution network operators beyond their Week 24 Grid Code obligations.

Figure 4.1 summarises the main fuel and plant types in Table F.3 in pie-chart form. The main renewable types of generation shown are: wind, waste & landfill, biofuels and hydro. The capacity of wind generation includes both onshore and offshore wind. The waste and landfill plant types have been grouped together as “man-made” forms of renewable energy. Figure 4.1 also shows that CHP is a prominent plant type for small-scale and embedded power plants.

In Table F.3, the information in respect of the Scottish distribution companies (i.e. SHEPD and SP Distribution Ltd) has been updated this year. However, updated information in respect of the distribution companies in England and Wales was not available in time for publication in this Statement and, for those DNOs, last year’s data has been re-used. The data for England & Wales has therefore been supplemented by embedded generation data of our own.

In view of the relatively high volume of data relating to the distribution systems in England and Wales, a cut-off point of 5MW was originally adopted to reduce the data collection burden on the distribution network operators (i.e. embedded plant of less than 5MW located in England and Wales was not included). The data for England & Wales has since been supplemented by embedded generation data of our own, which includes some generation projects with an installed capacity of less than 5MW. The information relating to the Scottish distribution systems provided by the Scottish network operators does not have a lower cut-off level. For some User Systems, the information is provided on an individual power station basis while for others the information is provided on a GSP basis.

There is a current Grid Code requirement (PC.A.3.1.4 of the Planning Code refers) for distribution network operators to inform NGET of the summated capacity of embedded Medium and Small power stations within their area and the allowances made for these in their demand forecasts projected for the time of the system peak. This information is summarised in Table 4.1. Please note that the 'Zone Number', referred to in Table 4.1, is the 'Demand TNUoS Tariff Zone' rather than the 'SYS Study Zone', both of which are introduced in "Use of System Tariff Zones" in Chapter 6.

For comparison purposes, Table 4.1 gives totals of installed capacity for each DNO summated from the data in Table F.3. These figures give an approximate indication of the proportion of installed capacity of embedded generation that the distribution network operators assume is considered to be contributing at the time of the system peak. The contribution assumed by network operators to be firm at other times, including the time of the local peak demand for which the Grid Supply Point is chiefly designed, rather than the time of peak demand, is not reported.

The information presented in Table F.3 and Table 4.1 may, in some respects, be incomplete, but does nevertheless provide an initial useful insight into the different types of embedded generation and into the total demand in the system (i.e. demand on the national electricity transmission system plus embedded generation capacity 'netted off' in the distribution network operators' Grid Code demand submissions).

Government Targets and Obligations

As part of its policy to reduce carbon emissions in 2010 by 20% of their 1990 level in order to help deliver the UK's Climate Change Programme, the government set a target of increasing the electrical capacity of combined heat and power in the United Kingdom to 10GW by 2010.

In addition to this CHP objective, the government also set a target for 2010 for the proportion of electricity sold by suppliers to be sourced from renewable fuels through the Renewables Obligation. The introduction of these instruments, together with the trading arrangements for the Renewables Obligation (RO) certificates, has provided a significant boost to the economics of renewables. However, it is important to also have the successful introduction of an appropriate planning framework in order to facilitate the speedy development and construction of renewable generation in line with the Climate Change Programme and targets.

In presenting our own view of projected peak demand and electricity requirements our assumptions about future growth in embedded CHP and renewable generation are outlined in Chapter 2 (Electricity Demand).

Renewables Obligation

The main instrument for encouraging the development of renewable generation prior to April 2002, was the Non-Fossil Fuel Obligation (NFFO) in England & Wales and the Scottish Renewable Order (SRO) in Scotland. Under these schemes the Department of Trade and Industry selected and approved renewable generating projects following a tendering process. Electricity suppliers were then obliged to purchase power from these generators, the extra cost of doing so being reimbursed from the Fossil Fuel Levy imposed on customers' bills.

A government aim is for renewable energy to make an increasing contribution to energy supplies in the UK, with renewable energy playing a key role in the wider climate change programme. The Renewable Obligation, the Renewable Obligation (Scotland) and the Renewable Obligation (Northern Ireland) are designed to incentivise renewable generation in the electricity generation market. These schemes were introduced by the Department of Trade and Industry, the Scottish Executive and the Department of Enterprise, Trade and Investment respectively and are administered by Ofgem.

Since 2002 Ofgem has published annual reports on the Renewables Obligation and readers are advised to consult these for more detail on the subject. The annual reports are available on the Ofgem website. The latest issue is in respect of the period 2007-08.

The first Renewable Obligation Order came into force in April 2002 as did the first Renewable Obligation Order (Scotland). These Orders were subject to review in 2004, 2005, 2006 and

2007. The first Renewables Obligation Order (Northern Ireland) came into force in April 2005. New Orders came into force on 1 April 2006 and 1 April 2007. The Renewables Obligation Order (Northern Ireland) 2007 was amended on 19 October to allow for its continued effective operation within the new Single Electricity Market arrangements for Ireland with effect from 1 November 2007.

These Orders place an obligation on licensed electricity suppliers in Great Britain and Northern Ireland to source an increasing proportion of electricity from renewable sources. In 2007-08, this was 7.9% in Great Britain and 2.8% in Northern Ireland. The size of these obligations increases year on year such that for Great Britain they reach 10% of electricity sales in 2010 and 15% in 2015.

Suppliers meet their obligations by presenting sufficient Renewable Obligation Certificates (ROCs), also referred to as ‘Green Certificates’, to cover their obligations. These certify that a generating station has generated an amount of electricity from renewable sources and that this electricity has been supplied to customers in Great Britain. Where suppliers do not have sufficient ROCs to meet their obligation, they must pay an equivalent amount (referred to as the buy-out price) into a fund. An obligation period runs from 1 April to 31 March each year. Ofgem have published a buy-out price for the RO of £36.99 per MWh for the period 1 April 2010 to 31 March 2011. The money accrued from the fund is redistributed to all suppliers in proportion to the amount of renewable power they actually buy, as defined by the number of certificates they hold. The government intends that suppliers will be subject to a Renewables Obligation until 31 March 2027.

When the RO was first introduced, the most prevalent technology type (in terms of the number of accredited generating stations) was landfill gas with 202 accredited stations at 1st April 2002. The number of landfill gas stations being accredited has reduced significantly and, in 2008-09, 14 landfill gas generating stations were accredited.

The most prevalent technology in the 2006-07 obligation period, in terms of the number of stations becoming accredited, was photovoltaic with 662 stations being accredited. The most prevalent technology, in terms of capacity becoming accredited, in this period was on-shore wind. On-shore wind stations made up approximately 47% of the total renewable capacity installed and accredited under the RO in the 2007-08 obligation period.

In May 2007 BERR issued a consultation on a number of proposed changes to the Renewables Obligation. In their response, the government decided upon a number of changes to be implemented from 1 April 2009. These include:

- Banding the RO so that different levels of support are provided to different technologies;
- Extending obligation levels up to 20% on a “guaranteed headroom” basis;
- A change to the treatment of generators supplying through private wire networks;
- Publishing annual sustainability reporting for Biomass; and
- Deeming energy from waste at 50% renewable content and allowing a higher percentage where adequate sampling procedures are in place.

Further to this, BERR launched a second consultation in June 2008 outlining how the government proposed to enact the changes proposed in the 2007 consultation. These proposals would be implemented from 1 April 2009 and include the following:

- Grandfathering generation in existence prior to 11th July 2006, with the exception of co-firing without CHP and microgeneration stations.
- Band the RO to provide more support to certain technologies over others.
- Establish processes for settling the obligation, allowing suppliers to calculate their obligation.
- Require biomass generators to report on sustainability
- Fund Ofgem’s administrative costs from the buyout fund
- Set a separate Combined Heat and Power Quality Assurance (CHPQA) efficiency criteria for renewable Combined Heat and Power (CHP) schemes.

The latest consultation on financial incentives for renewable generation closed on 15 October 2009. DECC have now published their recommendations which fall under the following main headings:

- Extension of the life-time of the RO to at least 2037;
- Introduction of a 20 year limit on support under the RO;
- Removal of the 20 Renewable Obligation Certificate (ROC)/100MWh limit in the RO;
- Retention of the existing fixed targets until 2015/16, with a headroom only mechanism after that date;
- An increase in the level of headroom from 8% to 10%; and
- Opening up the RO to include renewable generation outside the UK that meets specific criteria to help meet our EU target in the most cost effective way.

Further information can be found on the DECC website:

http://www.decc.gov.uk/en/content/cms/consultations/elec_financial/elec_financial.aspx

Environmental Targets for Renewables & Emissions

The UK Government has recently signed up to two environmental targets one relating to renewable energy and one to green house gas (GHG) emissions. The former relates to the EU renewable target of 20% of energy to come from renewable sources by 2020, which translates for the UK to 15% due its low starting point. The latter was recently confirmed in the 2009 Budget statement when the Government announced the first three carbon budgets at levels leading to a 34% reduction in GHG emissions by 2020 which will put the UK on the flight path to the 80% reduction target by 2050. To see what potential power station developments and network reinforcements are required to enable these 2020 targets to be met please refer to the section on the Electricity Networks Strategy Group (ENSG) report under ”Indicative Reinforcements required to meet Environmental Targets" in Chapter 8.

Climate Change Levy

Another instrument of the government's policy to reduce environmental emissions is the Climate Change Levy (CCL). This is an energy tax payable by all industrial and commercial businesses since April 2001. It is levied on energy supplies, the rate varying depending on the fuel. The levy initially set for electricity was 0.43p/kWh. From April 2007 the CCL has been increased in line with RPI, and the rate for electricity for 2008/09 is 0.456p/kWh, up from 0.441p/kWh in 2007/08. Energy intensive businesses can receive up to 80% discount on the levy if they enter into agreements with the government to undertake significant energy efficiency improvements.

Electricity generated from renewables is exempt from the CCL, thus currently benefiting developers of renewable electricity by an extra 0.456p/kWh. As a result, developers of qualifying renewable schemes could receive a minimum support of 4.032p/kWh in 2008/09, (i.e. the buy-out price of 3.576p/kWh under the RO plus 0.456p/kWh under the CCL). This is in addition to the value of the share-out of the buy-out kitty among those suppliers who have bought green energy under the Renewables Obligation.

Growth and Location of Wind Farms

There are clear indications of significant activity associated with the development of wind generation and, accordingly, future activity in this area is worthy of further consideration. Wind farms may, of course, be embedded or non-embedded and may be classified as Large, Medium or Small power stations. Accordingly, relevant information can be found from two sources of data within this Statement.

The first is Table F.3 in Appendix F, which presents information on embedded Medium and Small power stations. As explained previously, the information contained in Table F.3 is not necessarily complete and, as such, should not be relied up on. Much of the information contained in Table F.3 has been voluntarily sourced by the distribution network operators and

NGET cannot therefore guarantee its accuracy. Nevertheless, the information it contains does provide a useful initial indicator to the types and capacity of embedded Medium and Small generation connected to distribution networks. The DNOs denoted “SHEPD” and “SPD” in zones 1 and 2 are in Scotland. The other DNOs are inEngland & Wales.

The second source is Table F.1 in Appendix F, which presents information on directly connected power stations and Large embedded power stations. Accordingly, Table F.1 includes information on all Large wind farms, whether directly connected or embedded, and Medium and Small wind farms, that are directly connected to the national electricity transmission system. Table 5.4 in Chapter 5 shows the reported increase in onshore and offshore wind capacity from 2009/10 to 2016/17 inclusive.

Effect on Power Transfers

General Considerations

One effect of an increasing proportion of embedded generation will be to reduce the flow across the interface between the transmission and distribution networks. This will tend to delay the need for reinforcement of parts of the transmission network but it is unlikely to remove the need for the substations that exist at the interface between the transmission and distribution systems (i.e. the Grid Supply Points). These will continue to be required to balance the fluctuations between generation and demand in that specific part of the distribution network from minute to minute.

In a few areas it is possible that embedded generation may increase to a level where there could be electricity exports from distribution networks to the transmission system. Provided such transfers are within the capacity of the super grid transformers, this is not expected to lead to major technical difficulties. The general reduction in the power flow from the transmission to distribution networks does not necessarily lead to a similar reduction in the bulk power transfer across the transmission system. These bulk transfers, and therefore the need for system reinforcements, are a function of the size and geographical location of both generation and demand.

Power stations, particularly Large Power Stations, tend to be located in clusters near fuel sources. This, coupled with their size (i.e. capacity) relative to that of individual demands, means that generation developments (openings or closures) tend to exert the greater influence on the need for transmission reinforcements. Demand changes are normally less localised and are subject to a more even rate of change. Having said that, in some areas (e.g. where demand exceeds local generation) demand can exert the greater local influence and as such there remains a need for accurate demand forecasts in terms of both level and location.

The section in Chapter 7 on "Transmission System Performance" considers the performance of the national electricity transmission system against the 'SYS background', includes two figures (Figure 7.1 and Figure 7.2) which provide an overview of the power flow pattern at the time of ACS peak demand for the years 2010/11 and 2016/17 respectively.

Power transfers across the system at any given time are a function of the output of the power stations actually operating at that time rather than of their installed capacity. The disposition of such plant changes as the overall demand level changes throughout the year. The predominant north to south power flows illustrated in Figure 7.1 and Figure 7.2 reflect the fact that whilst around 50% of the peak demand is located in the south (i.e. south of the midlands to south border), much of the less expensive generation is located in the north. These heavy transfers from the north to the south prevail throughout most of the year since, as demand falls, less of the relatively more expensive generation in the south is used.

Power transfers across the national electricity transmission system depend on the disposition of generation and demand regardless of whether it is directly connected to the national electricity transmission system or embedded within a distribution system. To reduce bulk flows would require a general movement of economic generation (directly connected or embedded) nearer to the major load centres (e.g. the south). Even then it would not necessarily follow that the north to south power transfers would reduce. For instance, if new embedded generation were to be located in the south its operation could displace the operation of less economic plant also in the south, in which case transfers would be unchanged. Alternatively, if new embedded generation were to be located in the north of the system it is more likely that north to south transfers would increase.

Transmission Network Use of System Charges (TNUoS)

The Balancing and Settlement Code (BSC) and TNUoS charges, including to whom they apply, are explained in Chapter 10 (Market Overview).

Generators that are not registered within the BSC are exempt from TNUoS charges and payments. Relevant power stations would be Licence exempt, embedded and registered within a Supplier BM Unit. The output of these power stations will have already been accounted for in the supplier's demand figures upon which TNUoS charges are based.

Under the above circumstances an embedded power station which is both licence exempt and not party to the BSC will not be charged TNUoS and may be able to reduce the TNUoS charges payable by the host supplier (i.e. the supplier in whose BM Unit the power station is registered) by generating on the Triad legs.

Fluctuating Unpredictable Output and Standby Capacity

The output of some renewable technologies, such as wind, wave, solar and even some CHP, is naturally subject to fluctuation and, for some renewable technologies, unpredictable relative to the more traditional generation technologies. Analyses of the incidence and variation of wind speed, the expected intermittency of the national wind portfolio would not appear to pose a technical ceiling on the amount of wind generation that may be accommodated and adequately managed. However, increasing levels of such renewable generation on the system would increase the costs of balancing the system and managing system frequency.

It is a property of the interconnected transmission system that individual and local independent fluctuations in output are diversified and averaged out across the system. Moreover, the interconnected system permits frequency response and reserves to be carried on the most cost effective generation or demand side service provider at any particular time. These properties of the transmission network permit intermittent/variable generation to be used with lower standby and frequency control costs than would otherwise be the case.

Given the variable and unpredictable nature of some renewable technologies such as wind, the proportion of conventional generation needed to be retained in the electricity market so that current levels of security of supply are not eroded is the subject of recent research that has been recently published. The report "Growth Scenarios for the UK Renewable Generation and Implications for future Developments and Operation of electricity Networks" (BERR Publication URN 08/1021 June 2008) indicates that in the future "the probability of having low wind output at times of peak demand is considerable. There is a 10% probability that wind output will be below about 20% of installed capacity at times of peak demand in winter and a 5% probability of output being below about 15%."

This implies that, for larger wind penetrations, the wind capacity that can be taken as firm is not proportional to the expected wind energy production. It follows that the electricity market will need to maintain in service a larger proportion of conventional generation capacity despite reduced load factors. Such plant is often referred to as "standby plant".

Balancing Mechanism Participation

Users registered within the Balancing and Settlement Code (BSC) may volunteer to participate in the Balancing Mechanism (BM) regardless of whether they are directly connected to the transmission system or embedded within a distribution system. The minimum offer size in the BM is 1MW.

National Grid's responsibility in the BM is limited to balancing generation and demand and to resolving transmission constraints. This includes a duty and financial incentive under the System Operator Incentive Scheme to purchase Balancing Services economically. The Grid Code requires all embedded participants on the BM to ensure that their physical notifications, bids and offers are feasible with respect to their host network.

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.

Further information on Balancing Services can be obtained on the National Grid website:

http://www.nationalgrid.com/uk/Electricity/Balancing/services/

A useful reference document on the management of constraints and incentives ("BSIS Reference Document - An introduction to National Grid Electricity Transmission System Operator (SO) Incentives") is available under "System Operator Incentives":

http://www.nationalgrid.com/uk/Electricity/soincentives/docs/

Ancillary Services

Balancing Services (which include Ancillary Services) and Balancing Services Use of System (BSUoS) charges (including to whom they apply) are explained in Chapter 10 (Market Overview).

National Grid has actively encouraged and facilitated market arrangements for the provision of ancillary services. Whilst BSUoS charges are levied on all BSC signatories, the provision of ancillary services is not limited to those signatories. Accordingly, the provision of such services is open to any party who can provide a service, including embedded generation, cost-effectively.

System operators at the national control centre use ancillary services. They are only able to call-off a limited number of service blocks in the short period of time available. Thus, for practical reasons, minimum sizes are specified for control use. These are:

- frequency response : 3MW each despatch instruction
- reserve : 3MW each despatch instruction
- reactive : $^{+}/_{-}$ 15Mvar at station terminals
- black start : must be capable of charging circuit

However aggregators/agents are encouraged as this facilitates the provision of practical service blocks, enhances the dependability of service provision and reduces costs due to simplified communication requirements.

Prior to NETA, much experience was gained with a significant number of embedded service providers (generation and demand). However, whilst National Grid now specifies service levels at station terminals rather than at the National Grid/service provider interface, to date it has not been successful in entering into a reactive contract with embedded generation not registered within the BSC. This illustrates the difficulties and costs faced by small reactive providers acting through an intermediate network/distribution system.

Licence exempt embedded generation not registered within the BSC may receive benefits from the host Supplier in recognition of the consequent reduction to that Supplier's obligation to pay BSUoS charges. However, if the embedded generation were to choose to participate in the Balancing Mechanism, then registration within the BSC would be necessary and appropriate BSUoS charges would be levied.

The results of two consultations (one on Response and one on Reserve) on the challenges of operating the transmission network in 2020 have been published under "Future Requirements":

http://www.nationalgrid.com/uk/Electricity/Balancing/services/FutureRequirements/

Technical and Data Requirements

All Generators with Large power stations are obliged to sign onto the Connection and Use of System Code (CUSC). This includes signatories to the Balancing and Settlement Code (BSC). In addition parties who are not holders of a Licence but who have registered within the BSC are also required to sign the CUSC.

The CUSC places a number of obligations on signatories, which includes compliance with the Grid Code. Amongst other things, the Grid Code sets out technical requirements for the various classes of generation (e.g. Large, Medium, Small, embedded and directly connected External Interconnections) as well as requirements for data to be supplied to National Grid as NETSO.

Some of the earlier technologies used in wind turbines were very sensitive to voltage depressions, even where such depressions lasted for very short periods of time, such as the 140 milliseconds that protective equipment on the national electricity transmission system typically take to remove a line fault caused by lightning. Such faults can result in voltage depressions over an extensive area of the system potentially causing a large number of wind turbines to trip as a result of a common cause. In recognition of this the Grid Code has now been revised to include revised minimum technical characteristics for such generation technologies.

Medium and Small embedded generation which is Licence exempt and which is not registered within the BSC, is not required to sign on to the CUSC and, in consequence, is not obliged to comply with the Grid Code. Nevertheless, it is recognised that such embedded generation does impact on the overall performance of the transmission system and its operation.

Embedded Medium power stations are most likely to have a material effect. Small power stations may also be important particularly if connected at the first voltage transformation level of the Grid Supply Point.

To enable the Transmission Owners to meet their obligations with regard to planning the transmission system and National Grid, acting as NETSO, to further meet its obligations with regard to operating the national electricity transmission system it is important that Users submit sufficient and timely information on all embedded generation that may have a material effect on the transmission system. Amongst other things, the following are required:-

- technical and other information in respect of any new embedded generation which may be material to the design and operation of the transmission system in order that any necessary works can be evaluated and initiated in a timely fashion; and
- sufficient notification to enable any necessary works to be completed and ensure the transmission network is safe and secure before the embedded generation is energised.

It is also important that relevant embedded generation meets, where appropriate, certain minimum technical requirements (e.g. so that they are able to participate in the provision of ancillary services).

At the time of writing, power stations which are capable of exporting between 50MW and 100MW to the total system in Great Britain, connecting since 30 September 2000 may apply to apply to the Department of Trade and Industry (DTI) to seek a Licence Exemption. The DTI then consults all interested parties including National Grid. Power stations, which are not capable of exporting 50MW or more to the total system, are automatically exempt from the requirement to hold a generation licence. On receipt of the consultation documents from the DTI, we 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 is included in our response to the DTI consultation document and at the same time we offer an agreement, also containing the above information, where appropriate. Such agreements would not automatically subject the Generator to TNUoS charges, but would provide for any necessary data exchange.

It is recognised that some Generators with embedded generation would not want to have a contract or any other commercial arrangement with National Grid. The longer term solution to these interface issues with embedded generation is for National Grid to work with the host distribution network operators to obtain the necessary information, ensure co-ordination of developments and also to pass across certain technical responsibilities, currently in the Grid Code, to the network operator. This approach would facilitate a single contract relationship between the embedded generation and the host distribution network operator.

Summary

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 continuing increases in embedded generation. It is important for National Grid to play its part in facilitating this 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 national electricity 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 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. . There is considerable ongoing work in this area which is published by the Electricity Networks Strategy Group (ENSG):
http://www.ensg.gov.uk/index.php?article=126

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. It is anticipated that balancing volumes and costs will increase as the wind portfolio increases. However, 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.

Further information can be obtained from the national Grid website:

http://www.nationalgrid.com/uk/Electricity/Operating+in+2020/

Table 4.1 - Embedded Medium and Small Generation Netted off Demand Forecast Submissions by DNOs

DNO Network	Zone Number	Zone Name	Installed Capacity (MW) from Table F.3	Generation Netted Off at Time of System Peak (MW)
SHEPD	1	Northern Scotland	336	101
SP Distribution Ltd	2	Southern Scotland	528	190
CE Electric (NEDL)	3	Northern	642	252
United Utilities (Norweb)	4	North West	1085	627
CE Electric (YEDL)	5	Yorkshire	885	460
SP MANWEB	6	North Wales & Mersey	1088	23
Central Networks (East)	7	East Midlands	547	120
Central Networks (West)	8	Midlands	430	78
EdeF Energy (EPN)	9	Eastern	984	279
Western Power Distribution (South Wales)	10	South Wales	410	61
EdeF Energy (SPN)	11	South East	714	228
EdeF Energy (LPN)	12	London	368	20
Southern Electric Power Distribution	13	Southern	608	572
Western Power Distribution (South West)	14	South Western	338	50
Totals (MW)			8963	3060

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Chapter 5

Plant Margin

Introduction

This chapter brings together information on generation capacity from Chapter 3 (Generation Capacity) and forecast ACS (average cold spell) unrestricted peak demand from Chapter 2 (Electricity Demand) and examines the overall plant/demand balance on the national electricity transmission system by evaluating a range of potential future plant margins.

However, 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. Indeed National Grid believes that the relatively high margins presented in the various tables and figures of this chapter are unlikely to occur in practice for a number of reasons that are discussed in the main text.

The plant margins presented have been evaluated on the basis of a range of different backgrounds. These backgrounds take some account of the uncertainties relating to future generation, which include: the relative likelihood of prospective new future generation projects proceeding to completion; as yet un-notified future generation disconnections (closures), e.g. LCPD closures; and 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.

There are a number of definitions of plant margin in current usage; and each definition is appropriate to a particular purpose. Naturally, the calculated value of plant margin also varies along with the definition. A discussion of two of the most useful definitions is included in the section headed "Plant Margin Terminology" in Chapter 5). That section also contains other related explanatory information and readers, who are unfamiliar with current terminology, are advised to first read that section before returning to the main body of the chapter.

The chapter concludes with a brief report on the related issue of gas and electricity market interaction.

Plant Margins on Different Generation Backgrounds

Generation Commissioning Backgrounds

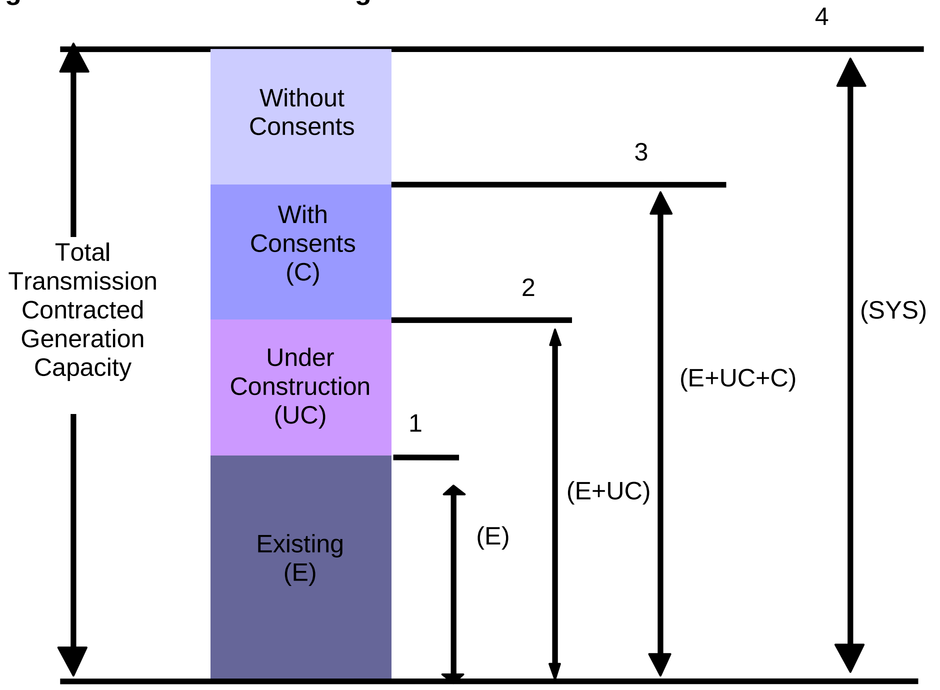
Unless otherwise stated the network analyses (e.g. the illustrative power flows, the loading on each part of the national electricity transmission system and the fault levels) presented in this Statement are based on the SYS background. Amongst other things, the SYS background includes existing generation projects and those proposed new generation projects for which an appropriate Bilateral Agreement is in place. Accordingly, most of the studies and analyses presented assume that all of the generating plant planned for commissioning over the period from the 2010/11 winter peak to the 2016/17 winter peak, will commission.
(reference table(s) in chapter 3)

However, unless plant is already under construction there can be only limited certainty that any particular project will proceed to completion and, accordingly, there are a number of areas of uncertainty relating to the future generation position and consequently the future plant/demand position. These include:

- the possibility of termination or modification of longer term connection agreements before construction or commissioning;
- additional new connection agreements being signed;

- as yet un-notified plant closures;
- possible retention of generation assets by the owner for commercial reasons or the return to service of plant currently held in reserve. Table 3.11 identifies plant which, on the face of it, has the potential to return to service. However, in practice, the majority of this plant belongs to stations that have opted-out of LCPD, and will therefore not generate beyond 2015; and
- the possibility that some transmission contracted generation may not in the event be granted Section 36 consent.

Figure 5.1 - Generation Backgrounds



In view of these uncertainties, four different 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. These are illustrated in Figure 5.1.

- Background 1: 'Existing Background' (E)
  This background includes all transmission contracted generation plant that is already constructed and connected to either the transmission network or a distribution network
- Background 2: 'Existing or Under Construction Background' (E, UC)
  This background includes all the generation included under background 1, plus all future generation plant under construction.
- Background 3: '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 (see Chapter 10: "Market Overview"). 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 4: '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.

Table 5.1, Table 5.2, Table 5.3 and Table 5.4 provide subtotals by plant type for each of the four generation commissioning backgrounds for the years 2009/10 to 2016/17 inclusive. Table 5.5 provides totals for each of the four generation backgrounds for the years 2009/10 to 2016/17 inclusive. Table 5.5 also provides peak demands on the basis of the customer based unrestricted demand forecasts given in Chapter 2 (Electricity Demand), and also for the NGET 'Base' economic growth scenario. The forecast demand streams utilised in each of these tables exclude station demand as that element of demand is excluded from the station TEC. Figure 5.2 is a graphical version of the totals given in Table 5.5.

Figure 5.2 - Capacity Totals and Peak Demands

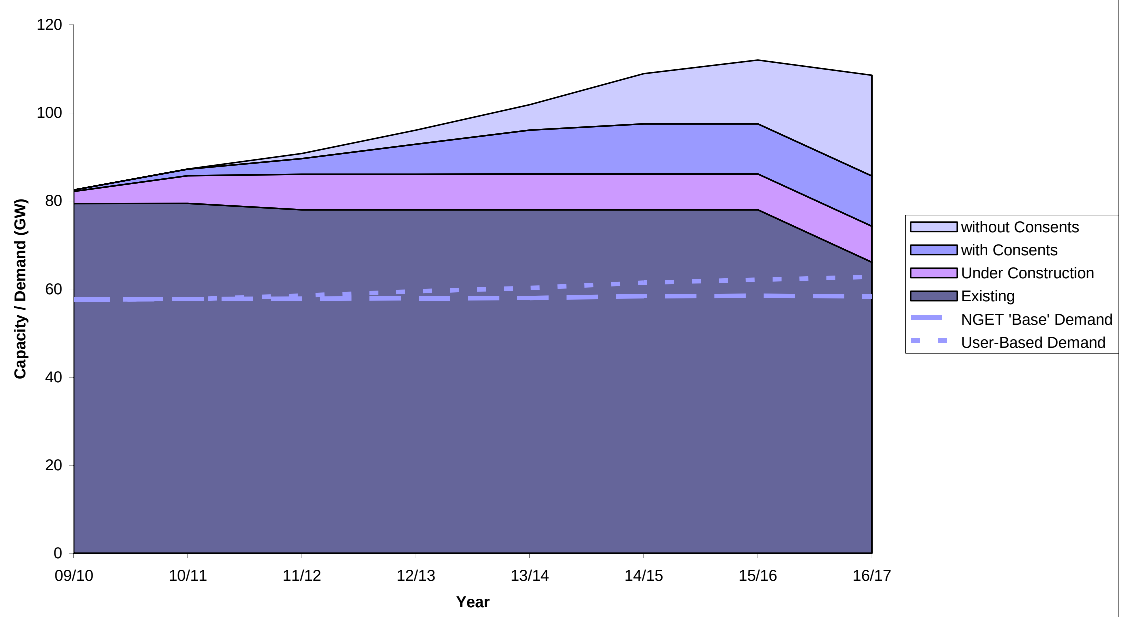
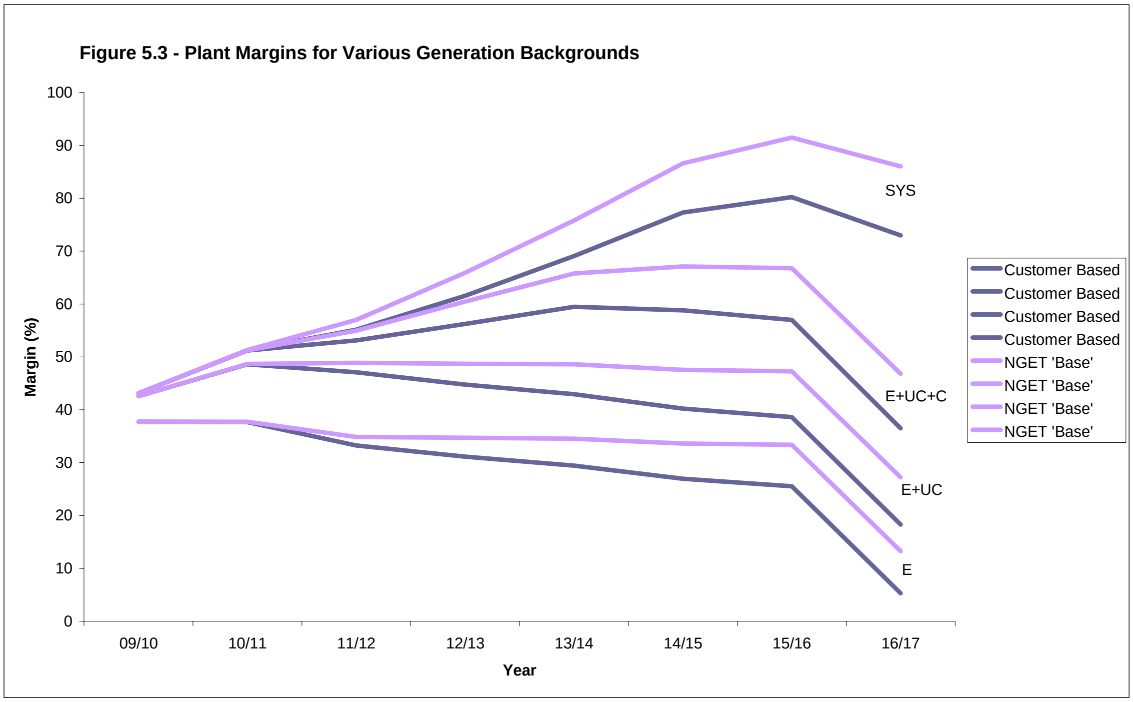


Table 3.6 and Table 3.7 of Chapter 3 identify, amongst other things, which new 'transmission contracted' generation planned to connect beyond 2009/10 is under construction. The tables also show how much of the remaining new 'transmission contracted' generation has, where relevant, obtained the necessary S36 and S14 consents, and how much has yet to obtain consent.

Table 5.6 and Figure 5.3 compare plant margins derived from the customer based demand forecast with those derived from our own base view of future demand growth given in Table 2.3. This is repeated for each of the above backgrounds to give six sensitivities in all, along with the SYS Background plant margins.



Generation Disconnection (Closure)

Generators are only required to give 6 months notice of closure of existing plant, which means that it is possible for us to receive formal notice of closure of plant within the first year of this Statement. It is important to read the Quarterly Updates to this Statement to identify any changes since the data was frozen for this NETS SYS on 31 December 2009.

The effect on the potential future plant margin of a particular assumption on future generating closure may, of course, be readily assessed. For example, if it were assumed that say 1GW of additional generating plant were to decommission (close) by the year 2016/17 (i.e. when the demand less station demand is some 58.4GW (as presented in Table 2.3**),** the Plant Margin in that year would obviously reduce by around 1.7 percentage points (i.e. 100*1GW/58.4GW = 1.7%) relative to the margins shown in Table 5.6 and the related figures.

Decommissioning

Table 3.9 lists generating units, that have either been formally notified by the owner as decommissioned (effectively TEC=0) or simply notified zero TEC covering the seven year period of this Statement; the total capacity of this plant is just over 2.9GW. Some, or all, of this plant has been retained by its owners for commercial reasons (e.g. placed in reserve or mothballed) and may under certain circumstances be returned to service at some future date (see "Decommissionings" in Chapter 3).

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.

The effect on the potential future plant margin of a particular assumption on re-commissioning generating units may again be readily assessed. For example, if it were assumed that say a 500MW unit were to re-commission by the 2016/17 winter peak**,** the plant margin in that year would obviously increase by around 0.9 of a percentage point (i.e. 100*0.5GW/58.40GW) relative to the margins shown in Table 5.6 and Figure 5.3.

The broad system effect of recommissioning mothballed plant is a function of the size and location of the particular plant or tranche of plant. The effects of returning individual plant to service must necessarily be considered on an individual basis both in terms of the overall system impact and on a site specific basis.

Wind Farm Contribution to Plant Margin

The section headed "Plant Margin Terminology" in Chapter 5 presented later in this chapter explains that the definition of Plant Margin, used for the purposes of this Statement, is such that no allowance is made within its calculation for the intermittent nature of the output and the level of output that, in consequence, can be relied upon from wind power plants at the time of system peak. This is unlike the assumptions on wind plant output underlying the system analyses, which are presented and discussed in "Modelling of the Planned Transfer" in Chapter 7 and in Chapter 8 (Transmission System Capability).

However, to enhance transparency and promote greater understanding within this chapter, additional plant margins have been calculated for a range of assumptions on the availability of wind generation capacity at the time of the winter peak as per customer based forecasts. Nevertheless, it should be remembered that such a range is quite arbitrary in this plant margin context.

Figure 5.4 - Plant Margins for various Wind Generation Availability Assumptions (relative to SYS Background)

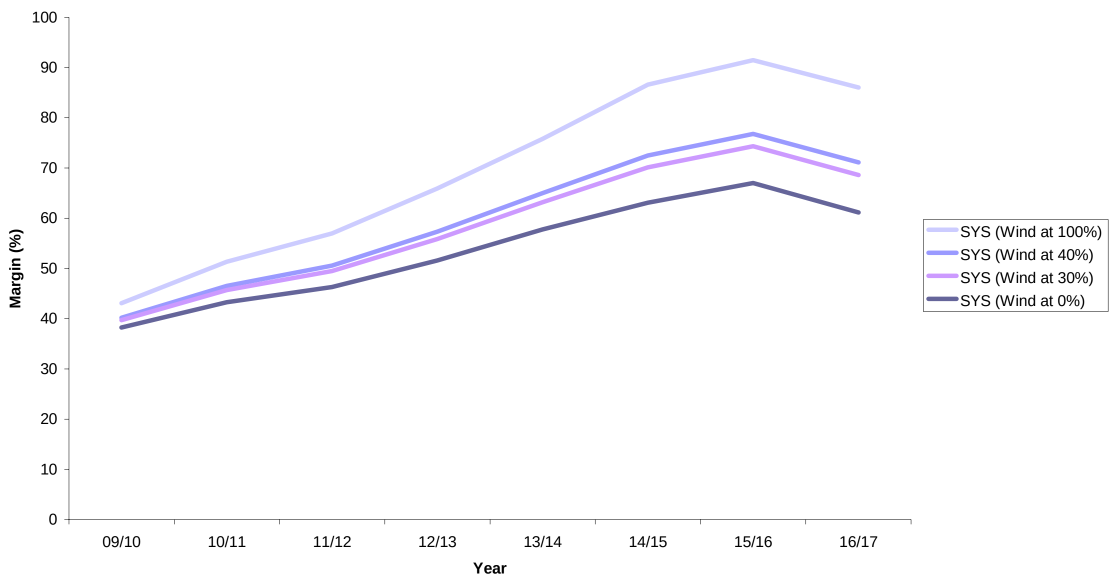


Table 5.7 and Figure 5.4 display plant margins for wind capacity availability assumptions of 40%, 30% and 0%. The SYS background (i.e. with an inherent 100% wind capacity assumption), as given in Figure 5.2 and Table 5.4, is also included for ease of comparison.

The effect of the LCPD closures in 2016/17 can be seen in Figure 5.3 and Figure 5.4.

Import and Export Assumptions Across Interconnections with External Systems

Table 3.10 of Chapter 3 (Generation) sets out the notional import and export capabilities across the External Interconnections at the time of our ACS Peak Demand. The table shows that the Cross Channel link provides a nominal import/export capability of 1988MW each way; although the link is normally used for imports. Similarly the Netherlands link will provide an import/export capability (from 2010/11 onwards) of 1320MW import and 1390MW export and again the link will normally be used for imports. The link to the Republic of Ireland will provide an import/export capability (from 2011/12 onwards) of 500MW import and 500MW export, and the link will normally be used for exports. The link with Northern Ireland has a nominal export/import capability of 500MW export and 80MW import. In this case the link will normally export. For the purpose of evaluating plant margins, import capabilities across External Interconnections are treated as generation and exports are treated as demand. This is explained in the section headed Plant Margin Terminology.

However, it is also explained in Chapter 7 (Transmission System Performance) that, when ranking generating plant in order of likelihood of operation at peak, for the purpose of power flow analyses, the level of imports and exports across External Interconnections is subject to special treatment. That treatment recognizes that, notwithstanding the export capability, the actual level of exports and imports is, itself, a function of the prevailing plant/demand balance.

The methodology is described in more detail in "Modelling of the Planned Transfer" in Chapter 7 but, in brief, the margin of installed generation over demand is calculated without imports or exports across the Cross Channel Link or the Netherlands Interconnector for the peak of each year. The resultant margin is then used to determine an assumed level of imports or exports across the two Interconnectors for the peak of each year. For margins up to and including a nominal 25%, the full import is assumed. For margins of 45% or over, the full export is assumed. For margins between 25% and 45% a linear reduction in exports/increase in imports is assumed such that at a margin of 35% there are no imports or exports across the Cross Channel Link or the Netherlands Interconnector.

Throughout this methodology a pragmatic assumption of 250MW export to Northern Ireland and 250MW export to the Republic of Ireland from 2011/12 onwards, is used and this is represented as negative generation. This approach differs from the methodology used to evaluate Plant Margins in this chapter, which also uses the pragmatic 250MW export to Northern Ireland and 250MW export to the Republic of Ireland from 2011/12 onwards, but treats this as demand in accordance with the definition of Plant Margin in the section headed Plant Margin Terminology presented later in this chapter. For the avoidance of doubt, the actual import capabilities of the Cross Channel Link (1988MW) and the Netherlands Link (1320MW) at peak have been used for Plant Margin evaluation. These are represented as generation; again in accordance with the definition of Plant Margin.

A particular result of the application of the approach used in "Modelling of the Planned Transfer" in Chapter 7 for ranking plant in order of likelihood of operation at peak is that there may be exports (rather than imports based on nominal capabilities) to France and the Netherlands at peak, the level of which would be a function of the prevailing plant/demand balance.

However, as previously mentioned, the Plant Margins discussed in the previous sections of this chapter have been calculated on the basis of the methodology of this chapter (i.e. based on the definition of plant margin given in the section headed Plant Margin Terminology presented later) rather than the methodology outlined above, which is used in "Modelling of the Planned Transfer" in Chapter 7 for a different purpose. Accordingly, the Plant Margins presented are based on calculations which treat the nominal import capability at peak across the Cross Channel Link of 1988MW and across the Netherlands Link (from 2010/11) of 1320MW as equivalent to generation. The pragmatic assumption of a 250MW export at peak to Northern Ireland and a 250MW export to the Republic of Ireland is, as previously mentioned, treated as demand. Should the transfers across both the Cross Channel Link and Netherlands Interconnector be reversed to give, say, a net export (rather than import) of 3378MW (1988MW + 1390MW), this would be treated as demand in the calculation of plant margin.

As an example, the impact of this in year 2010 would be to reduce total generation capacity for the peak of that year from 87290MW to 84102MW (a reduction of 3318MW) and increase peak demand from 57689MW to 61067MW (an increase of 3378MW). This would reduce the calculated margin from 51.3% to 37.7% (or 13.6 percentage points).

Transmission Congestion

Transmission congestion exists on certain parts of the national electricity transmission system and this is considered in Chapter 8 (GB Transmission System Capability). Congestion occurs when the transfer capability of certain parts of the transmission system is insufficient to carry the power transfers arising from the unconstrained operation of generating plant. In such circumstances, generation is either constrained on or constrained off to avoid violation the Licence Standard in relation to system operation. Plant, which is constrained off, may be considered to be 'sterilised' in that it is unable to contribute to meeting the demand and may therefore be regarded as non contributory towards the overall GB plant margin.

Recent and forecast growth in generation in Scotland is significant, partly due to the high volume of new renewable generation seeking connection in the area. Until sufficient transmission reinforcement works are in place to enhance transmission capability across the boundaries between the SHETL system, the SPT system and the NGET system the very low opportunities for the connection of new generation in the northern parts of the system will remain. The interim and enduring Connect & Manage arrangements may however, change this situation.

Amongst other things, Chapter 8 (Transmission System Capability) explains that the ‘planned transfer’ from Scotland to England exceeds the expected capability of that transmission boundary in all years even with the planned transmission reinforcements to enhance that capability. Accordingly, some of the generating capacity in Scotland will need to be constrained off and, consequently, may be regarded as ‘sterilised’. The level of plant required to be constrained off varies through the period. However, as a generalised illustration, if it were assumed that say 1GW of generating plant in Scotland were constrained off at, say, the time of the 2009/10 peak to limit the power flows from Scotland into England to within acceptable levels, then this would effectively reduce the overall plant margin, in that year, by around 1.7 percentage points (i.e. 100*1GW/57.6GW).

Interpretation

Broad Overview

It is worth repeating that, while plant margins based on several backgrounds have been considered, we do not attach any probability to the likelihood of occurrence of any particular background, including the SYS background. The range of backgrounds has been considered to enable readers to form their own view on potential future plant margins and do not represent our predictions of the future outcome.

The later section of this chapter: "Plant Margin Terminology" explains that a margin of installed generation capacity over peak demand is necessary for security of electricity supply and is not surplus or excess capacity. That section also explains that, for the purpose of calculating plant margins, power station TEC has been used. Power station TEC is net of station demand. Accordingly, the demand used in the calculation of plant margin also excludes station demand.

As a general observation, plant margins are generally numerically similar to the equivalent margins published in last year’s Statement. National Grid do not believe that the relatively high margins shown in Figure 5.3 and Table 5.6 will occur in practice; particularly in respect of the later years. Amongst other things, those margins do not assume any plant is removed from service through disconnection (other than that assumed for nuclear magnox and LCPD affected plant) or added through the return to service of currently unavailable (or decommissioned) plant. Nor do they take any account of additional new connection agreements being signed or the possibility that some transmission contracted plant may not, in the event, proceed to completion.

In particular the margins of Figure 5.3 and Table 5.5 take no account of wind farm intermittency. When reduced availability in wind farm output is taken into account, the apparent margins are naturally reduced significantly as illustrated in Figure 5.4 and Tables 5.6. Similarly, exports rather than imports across the Cross Channel Link and the Interconnection with the Netherlands at times of peak would also reduce the effective margin. The potential for transmission congestion to ‘sterilize’ portions of installed generating capacity provides further scope for reduced margins.

The National Grid based forecast demands are lower than their equivalent User-based demands and this is reflected in the higher plant margins calculated using the National Grid based forecast demands.

The margins for 2009/10 should be viewed against the background of higher certainty (e.g. relating to demand forecasts and plant availability) associated with the earlier years. Thus, a lower margin in the earlier years may provide the same level of generation security as a higher apparent margin in later years.

Finally, it is stressed that none of the margins presented can, at this stage, be said to be ‘correct’. However, the most probable margins are considered to be captured by the wide range given. This range of backgrounds, qualified by the comments on the potential for closures, the possibility of terminations, the possible return to service of plant that is currently unavailable, the possibility that there may be exports to, rather than imports from, External Systems at the time of peak, and the potential sterilisation of generating plant, may assist readers in formulating their own views on the subject. Table 5.7 attempts to give an indication of margins that have actually occurred in recent years.

Generation Market Drivers

As a result of the various uncertainties, not all of which have been reported in this chapter, there is the potential for a wide range of possible outcomes relating to generation. As a consequence, we have developed our own view of the likely developments into the future, which is considered alongside the SYS based backgrounds when undertaking our investment planning processes, but this is not detailed in this document.

In developing our own view of available generation capacity going forward, we have made an assessment of the potential impact of a number of physical, environmental and commercial drivers. The physical drivers include the ageing population of certain classes of generating plant. Environmental drivers include the impact of the introduction of the EU Emissions Trading Scheme (ETS) from 2005, the Large Combustion Plant Directive (LCPD) from 2008 and the development of offshore wind farms. Commercial factors, which are entwined with the drivers outlined above, include the impact of forward prices, generator rationalisations, mothballing of plant and ancillary services. In addition, developments in the commercial framework would influence the generation capacity available.

Gas and Electricity Market Interaction

The interconnected electricity transmission system in Great Britain provides for the efficient bulk transfer of power from sources of electricity generation to the demand centres. The main benefits of the national electricity transmission system are outlined in ”The Benefits of an Interconnected Transmission System" in Chapter 4. Amongst other things, the transmission system provides for power stations to be located remote from the demand centres. The choice of power station location would take account of a wide range of considerations including financing, environmental factors, land availability, fuel availability and cost, potential savings in fuel transportation costs and transmission access, as well as taking account of our Transmission Network Use of System (TNUoS) charges which we levy on our customers for making use of our transmission system. Transmission Network Use of System charges are described in Chapter 10 (Market Overview).

Table 5.4 shows that CCGT capacity has the potential to exceed coal capacity by 2016/17 as the major plant type.

Gas is transported from producer to gas consumer (e.g. CCGT power station) via National Grid’s gas transmission network for which transportation charges are levied. Thus, CCGT power stations could be viewed as a producer on the electricity transmission system and a consumer on the gas transmission network. This dual role gives rise to a degree of interaction between the electricity and gas markets. In particular, there are two elements in the gas market that have the potential to affect the level of available generation capacity: 'interruptible gas services' and 'CCGT arbitrage'.

Interruptible Gas Arrangements & Off Peak Capacity Product

The current interruptible arrangements apply until 30th September 2012. This is a service National Grid Gas offers to its customers which provides for lower gas transportation charges but, at times of high gas demand, allows it to shut off some or all of the gas supplied to the supply point for a specified maximum number of days within a year.

Gas supply could be interrupted by National Grid when there are transportation constraints on the National Gas Transmission network. In addition Shippers or Suppliers of gas can commercially interrupt their customers (e.g. CCGT station) either to balance their demand and supply portfolios or to sell gas onto the open market.

However, many of the power stations that would be affected (i.e. those with interruptible gas supplies) have back up supplies of distillate oil. Thus, providing there are no technical problems relating to switching to and from distillate oil, and providing adequate distillate capacity is available, then electricity generation can be maintained.

New market arrangements have been introduced which are effective from 1st October 2012 where the current NTS (National Transmission System) interruption arrangements are replaced by an off peak capacity product available via a day ahead pay-as-bid auction. National Grid NTS will be able to scale back such capacity holdings to manage constraints on the system.

CCGT Arbitrage

Gas-fired stations have the potential to respond to market price signals, decreasing their gas consumption when the electricity price is lower than the price of burning gas. This ability to arbitrage between gas and power is not restricted to power stations with National Grid gas interruptible contracts. In recent experience some firm CCGT power stations have self-interrupted over the winter for commercial reasons.

The willingness of the CCGTs to commercially interrupt themselves will be determined by the spark spread, which is itself influenced by the ability of the power generation sector to switch to other fuels and the level of electricity demand. Given the within-day profile of electricity demand, there is more scope for gas-fired generators to reduce their gas demand outside the peak half-hours of the day, as well as at other times of low electricity demand, such as at weekends and during holiday periods and either burn alternative fuel or switch generation to another station, burning coal or oil, within their portfolio of stations.

National Grid have carried out a detailed analysis to estimate the potential extent of CCGT arbitrage/demand side response within England and Wales, the results of which can be found in our 2009/10 Winter Consultation Report published in October 2009:

http://www.nationalgrid.com/uk/Gas/TYS/outlook/

http://www.nationalgrid.com/NR/rdonlyres/C3A81245-D988-48A4-80F2-5082F601E06D/37301/Winter_Outlook_Report_200910_01102009.pdf

Looking forward, we think that there is a strong case for all prospective new CCGTs to fit alternative fuel capability in order to provide additional flexibility to deal with periods of gas-electricity interactions, especially given the projected increase in gas' share of the electricity generation market.

Plant Margin Terminology

Introduction

In simple terms, the ‘plant margin’ is the amount by which the installed generation capacity exceeds the peak demand. Thus a system with a peak demand of 100MW and 120MW of installed generation has a 20MW plant margin, which represents 20% of the peak demand.

Some commentators assume that the plant margin is surplus or excess generation, which is not necessary to the power system. This is incorrect since generating units are subject to breakdown and need to be taken out of service from time to time for maintenance and repair. Generating units are not available to generate 100% of the time.

If it is assumed that only 85% of the total stock of generating plant could be predicted to be available at the time of winter peak demands several years ahead, then it would be necessary to plan to meet that peak demand (100%) with only 85% of the generation. This would mean that an installed generating capacity equivalent to about 118% of the peak demand (i.e. $100 \div 0.85$) would be needed in order to meet the peak. Further allowances would also have to be made for other factors such as the risk that the weather might be colder than the Average Cold Spell (ACS) conditions on which demand forecasts are based.

It was for reasons such as these that, in the past, large integrated power system utilities (e.g. the Central Electricity Generating Board in England and Wales) sought to achieve a plant margin of some 24% several years ahead of the event. This margin was referred to as the ‘planning margin’ rather than ‘plant margin’ (i.e. the planning margin was the value of plant margin used for planning the need for future generation).

An appropriate minimum value of ‘plant margin’ is therefore necessary for the security of electricity supply and does not represent surplus or excess generation. The actual required value of plant margin will be a function of the characteristics of the power system to which it applies.

The higher certainty associated with short term forecasts of say demand and generating unit availabilities means that the same level of security of electricity supply can be achieved with lower plant margins. Accordingly, the required margin for the earlier years would be much lower and the operational planning margin requirement for real time generation is generally around 10% depending on prevailing circumstances.

This chapter focuses on the planning time phase and relates to the security of supply provided by the generation capacity that is either already installed or is planned to be installed. The operational time phase, which relates, amongst other things, to the actual availability of the installed generation on the day, has not been specifically addressed.

In the privatised electricity supply industry within England and Wales and Scotland, there is no set standard for the planning margin and the need for new plant is determined by market forces.

Plant Margin Definitions

Plant Margin is defined in different ways in different documents.

The term "Plant Margin" is used in the License Standard, National Electricity Transmission System Security and Quality of Supply Standard (SQSS). In Appendix C of that document, its value is used to determine whether the Straight Scaling and/or the Ranking Order technique should be used in the evaluation of the Planned Transfer Condition. The SQSS definition of Plant Margin is:

"The amount by which the total installed capacity of directly connected Power Stations and embedded Large Power Stations exceeds the net amount of the ACS Peak Demand minus the total imports from External Systems. This is often expressed as a percentage (e.g. 20%) or as a decimal fraction (e.g. 0.2) of the net amount of the ACS Peak Demand minus the total imports from External Systems".

Whilst this definition is considered appropriate for the License Standard, it is not necessarily appropriate for other uses. When considering the Plant Margin of a particular Utility or group of Utilities it is more appropriate to consider the simple relationship between total installed generation capacity and peak demand. The current NETS SYS definition is given in the Glossary but is repeated below for ease of reference:

"The amount by which the total installed capacity of directly connected Power Stations and embedded Large Power Stations and imports across directly connected External Interconnections exceeds the ACS Peak Demand. This is often expressed as a percentage (e.g. 20%) or as a decimal fraction (e.g. 0.2) of the ACS Peak Demand".

The difference between the above two definitions lies in the fact that, the License Standard definition treats imports as negative demand but the NETS SYS definition treats imports as generation. Whilst the plant margin in MW terms remains the same, in percentage terms the NETS SYS margins are lower than would be the case using the License Standard definition. Please note that, whilst the wording of the NETS SYS definition of plant margin does not mention exports to External Systems, it is implicit that such exports should be treated as positive demand.

Accordingly basic Plant Margins presented in this chapter have been calculated on the basis of:

- the forecast ACS peak demand given in row 3 of Table 2.1 of Chapter 2 (Electricity Demand) which includes the assumed 250MW export at peak across the External Interconnection between Scotland and Northern Ireland, and the assumed 250MW export from 2011/12 onwards at peak across the External Interconnection between Wales and the Republic of Ireland as part of the demand on the national electricity transmission system; and

- the power station TEC values given in Table 3.5 of Chapter 3 (Generation) but with the 80MW TEC value for the export across the External Interconnection between Scotland and Northern Ireland, and the 500MW TEC value for the export from 2011/12 onwards across the External Interconnection between Wales and the Republic of Ireland removed.

Finally, it is also worth noting that the above underlying demand and generation assumptions used in the calculation of Plant Margin, as defined in this NETS SYS, differ from the demand and generation assumptions used in Chapter 7 (Transmission System Performance). For instance in Table 7.1 of Chapter 7 (Transmission System Performance), which is used for ranking generating plant in order of likelihood of operation at peak, different more pragmatic import/export assumptions may be used in recognition of prevailing circumstances.

Wind Farm Generation Availability

The question arises as to whether the installed generation capacity used for the purpose of the plant margin calculations in this Statement should be reduced in recognition of the high levels of future renewable generation which have inherently low availability (e.g. wind farms).

It has already been explained that the plant margin relates to the security of supply provided by the level of generation installed on the system to meet the demand. The "planning margin" is the value of plant margin calculated to be required several years ahead of the event to achieve the desired level of security at the time of the forecast winter peak demand. The chosen value of "planning margin" stochastically takes account of: the average winter peak availability of all generation; variations in the assumed average generation availability; variations in forecast peak demand due to weather; and basic forecasting error.

The selected value of the planning margin does not influence the definition or the calculation of the plant margin but rather the level of security it provides (derived from stochastic calculations). In view of this, for the purposes of this Statement, the installed generation capacity has not been reduced to compensate for low availability of renewable generation when calculating the basic plant margins.

However, to enhance transparency and promote greater understanding within this chapter, additional plant margins have been calculated for a range of assumptions on the availability of wind generation capacity at the time of the winter peak.

Use of TEC, CEC or RC

It may be argued that the "total installed capacity of a power station" is the aggregate of the Registered Capacities (or CEC) of all the individual Generating Units at that Power Station. However:

TEC reflects the maximum power the Generator can export across the system from a Grid Entry Point or a User System Entry Point;

The level of use of system rights for a Power Station is expressed in terms of the amount of TEC; and

Transmission infrastructure is designed on the basis of TEC.

Although TEC of a power station does not strictly fall within the definition of "total installed capacity", to the intents and purposes of the NETS SYS it is reasonable to take TEC as being equal to the "total installed capacity" of a power station. Accordingly, the plant margin has been calculated on the basis of TEC.

Station Demand

By definition, TEC is a gross-net-net quantity. That is it is net of power supplied through the Generating Unit's unit transformer and net of the auxiliary demand supplied through the station transformers. However, the "ACS Peak Demand" includes station transformer demand.

Accordingly, to avoid double counting in the calculation of plant margin, the demand to be used should be "ACS Peak Demand" less "station demand" at peak.

Accordingly, for the purposes of this Statement, the plant margin has been calculated on the basis of:

summated TEC of directly connected power stations, embedded Large power stations and imports to the national electricity transmission system from External Systems: and

"ACS Peak Demand" less "station demand" at peak since TEC is also net of "station demand".

Table 5.1 - Capacity by Plant Type (E)								
Plant Type	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Biomass	45	45	45	45	45	45	45	45
CCGT	25891	25930	25930	25930	25930	25930	25930	25930
CHP	2224	2224	2224	2224	2224	2224	2224	2224
Hydro	1129	1137	1137	1137	1137	1137	1137	1137
Interconnector	1988	1988	1988	1988	1988	1988	1988	1988
Large Unit Coal	4393	4393	4393	4393	4393	4393	4393	2284
Large Unit Coal + AGT	21467	21467	21467	21467	21467	21467	21467	17544
Medium Unit Coal	1102	1102	1102	1102	1102	1102	1102	0
Medium Unit Coal + AGT	1131	1131	1131	1131	1131	1131	1131	0
Nuclear AGR	8244	8244	8244	8244	8244	8244	8244	8244
Nuclear Magnox	1450	1450	0	0	0	0	0	0
Nuclear PWR	1200	1200	1200	1200	1200	1200	1200	1200
OCGT	579	579	579	579	579	579	579	579
Oil + AGT	3636	3636	3636	3636	3636	3636	3636	0
Pumped Storage	2744	2744	2744	2744	2744	2744	2744	2744
Small Unit Coal	783	783	783	783	783	783	783	783
Wind Onshore	1391	1393	1393	1393	1393	1393	1393	1393
Total Capacity (MW)	**79397**	**79446**	**77995**	**77995**	**77995**	**77995**	**77995**	**66094**

Table 5.2 - Capacity by Plant Type (E+UC)								
Plant Type	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Biomass	45	45	45	45	45	45	45	45
CCGT	27591	29340	31075	31075	31075	31075	31075	31075
CHP	2224	2224	2224	2224	2224	2224	2224	2224
Hydro	1129	1137	1137	1137	1137	1137	1137	1137
Interconnector	1988	3188	3188	3188	3188	3188	3188	3188
Large Unit Coal	4393	4393	4393	4393	4393	4393	4393	2284
Large Unit Coal + AGT	21467	21467	21467	21467	21467	21467	21467	17544
Medium Unit Coal	1102	1102	1102	1102	1102	1102	1102	0
Medium Unit Coal + AGT	1131	1131	1131	1131	1131	1131	1131	0
Nuclear AGR	8244	8244	8244	8244	8244	8244	8244	8244
Nuclear Magnox	1450	1450	0	0	0	0	0	0
Nuclear PWR	1200	1200	1200	1200	1200	1200	1200	1200
OCGT	579	579	579	579	579	579	579	579
Oil + AGT	3636	3636	3636	3636	3636	3636	3636	0
Pumped Storage	2744	2744	2744	2744	2744	2744	2744	2744
Small Unit Coal	783	783	783	783	783	783	783	783
Wind Offshore	800	831	831	831	831	831	831	831
Wind Onshore	1685	2264	2313	2313	2362	2362	2362	2362
Total Capacity (MW)	**82191**	**85758**	**86091**	**86091**	**86141**	**86141**	**86141**	**74240**

Table 5.3 - Capacity by Plant Type (E+UC+C)								
Plant Type	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Biomass	45	45	97	97	97	97	97	97
CCGT	27591	29340	32675	35255	36745	37726	37726	37726
CHP	2224	2224	2224	2224	2224	2224	2224	2224
Hydro	1129	1137	1137	1137	1137	1137	1137	1137
IGCC with CCS	0	0	0	0	800	800	800	800
Interconnector	1988	3188	3188	3188	3188	3188	3188	3188
Large Unit Coal	4393	4393	4393	4393	4393	4393	4393	2284
Large Unit Coal + AGT	21467	21467	21467	21467	21467	21467	21467	17544
Medium Unit Coal	1102	1102	1102	1102	1102	1102	1102	0
Medium Unit Coal + AGT	1131	1131	1131	1131	1131	1131	1131	0
Nuclear AGR	8244	8244	8244	8244	8244	8244	8244	8244
Nuclear Magnox	1450	1450	0	0	0	0	0	0
Nuclear PWR	1200	1200	1200	1200	1200	1200	1200	1200
OCGT	579	579	579	579	579	579	579	579
Oil + AGT	3636	3636	3636	3636	3636	3636	3636	0
Pumped Storage	2744	2744	2744	2744	2744	2744	2744	2744
Small Unit Coal	783	783	783	783	783	783	783	783
Wind Offshore	800	1545	1728	2358	2691	3061	3061	3061
Wind Onshore	1992	3041	3300	3375	3591	3686	3686	3699
Woodchip	0	0	0	0	350	350	350	350
Total Capacity (MW)	**82498**	**87249**	**89628**	**92913**	**96102**	**97547**	**97547**	**85660**

Table 5.4 - Capacity by Plant Type (SYS)

Plant Type	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Biomass	45	45	97	686	851	1431	1431	1431
Biopower	0	0	0	0	0	0	0	0
CCGT	27591	29340	32675	35255	37630	40791	43271	44666
CHP	2224	2224	2224	2224	2224	2224	2224	2224
Clean Coal	0	0	0	0	0	0	0	0
Hydro	1129	1137	1137	1137	1137	1137	1137	1137
IGCC with CCS	0	0	0	0	800	800	800	800
Interconnector	1988	3188	3188	3188	3188	3188	3188	3188
Large Unit Coal	4393	4393	4393	4393	4393	4393	4393	5850
Large Unit Coal + AGT	21467	21467	21467	21467	21467	21467	21467	17544
Medium Unit Coal	1102	1102	1102	1102	1102	1102	1102	0
Medium Unit Coal + AGT	1131	1131	1131	1131	1131	1131	1131	0
Nuclear AGR	8244	8244	8244	8244	8244	8244	8244	8244
Nuclear APR	0	0	0	0	0	0	0	0
Nuclear EPR	0	0	0	0	0	0	0	3300
Nuclear Magnox	1450	1450	0	0	0	0	0	0
Nuclear PWR	1200	1200	1200	1200	1200	1200	1200	1200
OCGT	579	579	579	579	579	579	579	579
Oil + AGT	3636	3636	3636	3636	3636	3636	3636	0
Pumped Storage	2744	2744	2744	2744	2744	2744	2744	2744
Small Unit Coal	783	783	783	783	783	783	783	783
Tidal	0	0	0	0	0	0	0	0
Wave	0	0	0	0	0	0	0	0
Wind Offshore	800	1545	2522	3446	4646	6703	7203	7203
Wind Onshore	1992	3082	3672	4858	5789	7013	7109	7307
Woodchip	0	0	0	0	350	350	350	350
Total Capacity (MW)	**82498**	**87290**	**90793**	**96072**	**101893**	**108916**	**111992**	**108550**

Table 5.5 - Capacity Totals and Peak Demands (MW)									
Background	**Generation / Demand (MW)**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
1	Existing Generation	79397	79446	77995	77995	77995	77995	77995	66094
2	Genration Under Construction	2794	6313	8096	8096	8146	8146	8146	8146
3	Subtotal (1+2)	82191	85758	86091	86091	86141	86141	86141	74240
4	Generation with Consents	307	1491	3536	6821	9961	11406	11406	11420
5	Subtotal (3+4)	82498	87249	89628	92913	96102	97547	97547	85660
6	Generation without Consents	0	41	1166	3160	5792	11368	14445	22890
7	Total (5+6)	82498	87290	90793	96072	101893	108916	111992	108550
8	Customer-Based Peak Demand	57649	57709	58528	59471	60267	61434	62140	62756
9	NG 'Base' Peak Demand	57649	57689	57833	57903	57967	58374	58487	58354

Table 5.6 - Plant Margins (%)									
Demand Forecast	**Generation Background (from Table 5.5)**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Customer-Based	1	37.7	37.0	32.7	30.6	28.8	26.4	25.0	4.9
Customer-Based	3	42.6	47.9	46.4	44.1	42.3	39.6	38.0	17.8
Customer-Based	5	43.1	50.5	52.4	55.5	58.8	58.1	56.3	35.9
Customer-Based	7	43.1	50.6	54.4	60.8	68.3	76.5	79.4	72.2
NGET 'Base'	1	37.7	37.7	34.9	34.7	34.6	33.6	33.4	13.3
NGET 'Base'	3	42.6	48.7	48.9	48.7	48.6	47.6	47.3	27.2
NGET 'Base'	5	43.1	51.2	55.0	60.5	65.8	67.1	66.8	46.8
NGET 'Base'	7	43.1	51.3	57.0	65.9	75.8	86.6	91.5	86.0

Table 5.7 - Plant Margins (%) for Various Wind Generation Availability Assumptions (relative to SYS Background)								
Generation Background	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
SYS (Wind at 100%)	43.1	51.3	57.0	65.9	75.8	86.6	91.5	86.0
SYS (Wind at 40%)	40.2	46.5	50.6	57.3	65.0	72.5	76.8	71.1
SYS (Wind at 30%)	39.7	45.7	49.5	55.9	63.2	70.1	74.4	68.6
SYS (Wind at 0%)	38.3	43.3	46.3	51.6	57.8	63.1	67.0	61.2

Table 5.8 - Plant Margins: Historical Outturns					
Year	**Total Capacity - January Update (MW)**	**ACS Corrected Peak Demand, excluding Station Demand (MW)**	**Plant Margin based on ACS Corrected Peak Demand (%)**	**Actual Peak Demand, excluding Station Demand (MW)**	**Plant Margin based on Actual Peak Demand (%)**
2005/06	75064	61600	21.9	59600	25.9
2006/07	76955	61200	25.7	57800	33.1
2007/08	76867	60800	26.4	60100	27.9
2008/09	79459	58400	36.1	58600	35.6
2009/10	82559	57649	43.2	58710	40.6

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Chapter 6

The Transmission System

Introduction

This chapter describes the existing and planned national electricity transmission system in terms of the electrical parameters of its components, its electrical and geographical structure and its planned development over the period to 2016/17. The chapter identifies the generation and demand tariff zones, which are used in the Transmission Network Use of System (TNUoS) charging process. To complete the picture, the chapter also reports on the main system boundaries which are used to illustrate the overall capability of the transmission system to transmit power and on the associated study zones used in the various technical analyses contained in this Statement.

In view of the volume of transmission system data presented in this chapter, most of the figures and tables are presented in Appendix A (Figures) and Appendix B (Data) and only referenced in the text. Such figures and tables have accordingly been prefixed with the letter 'A' or 'B' as appropriate (e.g. Figure A.1.2).

The latter part of this chapter includes some basic introductory material relating to the national electricity transmission system to assist readers, unfamiliar with power systems, in gaining a better understanding of the material contained in the Statement.

The SYS Background

The existing and planned national electricity transmission system described in this chapter, together with the customer-based demand forecasts described in Chapter 2 and the existing and planned generation background described in Chapter 3, 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 this chapter includes all transmission connection developments cited explicitly in the relevant Bilateral Connection Agreements as being necessary to permit the connection of the generation contained in the generation background of Chapter 3.

The "SYS background" is internally consistent. For example, the transmission background includes all transmission connection developments cited in the relevant connection agreement as being necessary to connect the generation contained in the generation background. 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 2009.

Scope

Accordingly, this chapter provides information on the existing transmission network and on 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 include, but are not 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 however considered ‘firm’, are also included. Such transmission reinforcement schemes are, nevertheless, associated with “Transmission Contracted” generation projects included in the generation background and may have an appropriate Transmission Owners Construction Agreement (TOCA) and Transmission Owners

Reinforcement Instruction (TORI) in place. The meaning of the terms TORI and TOCA are explained in the Glossary and discussed under "Transmission System Access" in Chapter 3).

In view of the uncertainty associated with future developments (particularly that relating to future transmission contracted generation), the timing of construction of infrastructure reinforcements is managed such that investments are made to well defined requirements. This means that in some cases construction is deferred to the last moment to avoid the risk of undertaking investments which may turn out to be unnecessary (e.g. where transmission contracted generation does not in the event proceed to completion), while at the same time ensuring that an efficient, co-ordinated and economic system, compliant with the Licence Standard is provided as required by the Transmission Licences.

Accordingly, the SYS background, upon which the bulk of this Statement is based, does not necessarily contain all the transmission reinforcement schemes that may in the event be required for compliance with the Licence Standard. This chapter focuses on the transmission network of the 'SYS background' which comprises the existing network together with those planned future transmission developments which are considered least likely to be varied to meet the changing needs of the system as it evolves.

Planned transmission developments may include:

- developments needed for 'transmission contracted' generation and demand cited in relevant bilateral agreements as being necessary precursors to the connection. These can include reinforcements to the infrastructure of the transmission system remote from the connection site as well as reinforcements local to the connection site; and

- infrastructure developments required to meet the general needs of the system as it evolves rather than the needs of any specific user (generation or demand).

The Existing and Planned Network

Network Parameters

The national electricicty transmission system for the winter of 2009/10 (as at the data freeze date of 31 December 2009) is shown geographically in Figure A.1.2. Table B.7a, Table B.7b and Table B.7c in Appendix B list the main planned developments to the transmission system in each year up to 2016/17 for each of the three transmission licensee's areas (SHETL, SPT and NGET).

Network parameter values for the existing and planned 400kV, 275kV and 132kV transmission system are included in Appendix B:

- Table B.1a, Table B.1b, Table B.1c
  Substations are referred to in some tables and figures by a 5 or 6 character code. The first four letters of the code refer to the site name and are listed in Table B.1a (for SHETL), Table B.1b (for SPT) and Table B.1c (for NGET). In other parts of this Statement, a fifth and sixth character is added. In these cases, the fifth character refers to the voltage level as follows:
  - 4 means 400kV
  - 2 means 275kV
  - 1 means 132kV
  - 6 means 66kV
  - 3 means 33kV

  For example Feckenham 400kV has code FECK4.
  For non-generator busbars, the sixth character of the busbar name is chosen to provide information about the busbar. In general, a value of '0' represents a

solid busbar. Busbar sections which are capable of being coupled but which are run separate due to fault level or load flow reasons, are given characters other than zero.
The three tables also show Demand and Generation Use of System Charging zones and the low voltage shunt susceptance at each node as supplied by users. The information contained in Table B.1c relates to the NGET 400/275kV transmission system. NGET own a number of busbars at lower voltages, which are embedded within distribution systems. For the purposes of this Statement these assets are not considered to be part of the national electricity transmission system but, nevertheless, Table B.1c does list these lower voltage busbars. For further information on this, users should contact National Grid as explained under "Further Information" in Chapter 1).

- Table B.2.1a, Table B.2.1b, Table B.2.1c
  These tables list the parameters of all circuits as at the winter of 2010/11, for each of the three transmission companies (SHETL, SPT and NGET respectively), including length, type (overhead line or underground cable), resistance, reactance, susceptance and post fault continuous seasonal ratings. Please note that circuit lengths are indicative only as they do not include detail such as 'cable entries' at substations.

  For composite circuits, which include component lengths of both overhead line and cable, the total length of each component (i.e. overhead line and cable) is given.

  The information contained in Table B.2.1c relates to the NGET 400/275kV transmission system. NGET own a number of circuits at lower voltages which are embedded within distribution systems. For the purposes of this Statement these assets are not considered to be part of the national electricity transmission system. Nevertheless, Table B.2.1c lists these lower voltage circuits. For further information users should contact National Grid as explained in "Further Information" in Chapter 1.

  The actual electrical connections between circuits at the substation are commonly referred to as the substation 'running arrangement'. Please note that, whilst Table B.2.1a, Table B.2.1b and Table B.2.1c assume particular running arrangements for the various substations on the system, these may be subsequently varied for instance to reduce fault levels.

- <u>Table B2.2a, Table B2.2b and Table B2.2c</u>
  These tables list the planned changes to the circuit parameters for each of the three transmission companies over the period from 2011/12 to 2016/17. The year of the change is also given together with the new parameter values. Again, where appropriate, where a change involves a composite circuit, the total length of each component (i.e. overhead line and cable) is given.

- <u>Table B.3.1a, Table B.3.1b and Table B.3.1c</u>
  These tables list the parameters of all grid supply transformers for the three transmission companies together with their nominal ratings (in MVA).

- <u>Table B.4a, Table B.4b and Table B.4c</u>
  These tables list typical transformer, Static Var Compensator and quadrature booster parameters respectively for the three companies. For exact values at a particular site, users should contact the relevant transmission company as explained under "Further Information" in Chapter 1.

- <u>Table B.5.1a, Table B.5.1b, Table B.5.1c</u>
  These tables give information on all reactive compensation plant owned by the three transmission companies, together with Mvar capabilities. The

system location of this plant is indicated in Figure A.2.4, Figure A.3.4 and Figure A.4.4.

- Table B5.2a, Table B5.2b and Table B5.2c
  These tables list the planned changes to reactive compensation for each of the three transmission companies over the period from 2011/12 to 2016/17. The year of the change is also given together with the new parameter values.

- Table B.6a, Table B.6b and Table B.6c
  These tables list indicative circuit breaker ratings for the three transmission companies.

Finally, to provide a more complete picture, Table B.8 in Appendix B lists planned developments on the transmission system that are beyond the scope of the NETS SYS. The schemes in Table B.8 are either planned for beyond 2016/17, or are associated with new customer connections which are due to connect beyond 2016/17.

Network Diagrams

The existing 2009/10 national electricity transmission system is shown schematically in Figure A.2.1 for SHETL, Figure A.3.1 for SPT and Figure A.4.1 for NGET. Looking forward, the national electricity transmission system as projected for the 2016/17 peak, including planned main extensions, is shown schematically in Figure A.2.4 for SHETL, Figure A.3.4 for SPT and Figure A.4.4 for NGET. As previously mentioned, the planned extensions include transmission connection developments cited explicitly in the relevant Bilateral Connection Agreements as being necessary to permit the connection of the generation contained in the generation background of Chapter 3. It is worth repeating, however, that the SYS background, and hence the figures, 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 2009.

The above schematic figures are complemented by the schematic power flow diagrams, which cover each winter peak from 2010/11 to 2016/17 inclusive and are presented in Appendix C.. The power flow diagrams also highlight planned developments in each year over the period. However, such planned developments are only shown in so far as they affect the figures. In addition, please note that the substation ‘running arrangements’ reflected in this series of figures are subject to variation (see Table B.2.1a, Table B.2.1b and Table B.2.1c). Table B.7a, Table B.7b and Table B.7c provides a more complete description of developments some of which may not be reflected in the power flow diagrams in Appendix C.

As mentioned previously, the system location of reactive compensation plant as at 2010/11, is shown schematically in Figure A.2.3 for SHETL, Figure A.3.3 for SPT and Figure A.4.3 for NGET. For details of additional reinforcement schemes, not forming part of the ‘SYS background’, which may be necessary for full compliance with the Transmission Licence security standards, please refer to Table 8.2 and "Indicative Reinforcements for Licence Compliance" in Chapter 8.

Use of System Tariff Zones

Transmission Network Use of System (TNUoS) charges reflect the cost of installing, operating and maintaining the national electricity transmission system (see Chapter 10: Market Overview). The basis of TNUoS charging is the Investment Cost Related Pricing (ICRP) methodology introduced in 1993/94.

<u>Generation TNUoS Tariff Zones</u>

The generation TNUoS tariff zones are defined in such a way as to meet the criteria for defining zones set out in the ICRP methodology. These criteria broadly require that: first, zones should contain nodes whose marginal costs fall within a specified narrow band; and second, nodes within zones should be both geographically and electrically proximate. The generation TNUoS tariff zones are depicted geographically against a backdrop of the 2009/10 national electricity transmission system on the "Charging" web pages:

http://www.nationalgrid.com/uk/Electricity/Charges/chargingstatementsapproval/

The geographic picture is complemented by Figure A.2.2 for SHETL, Figure A.3.2 for SPT and Figure A.4.2 for NGET, which present the generation tariff zones against the 2010/11 schematic/electrical backgrounds of each Transmission Area.

Demand TNUoS Tariff Zones

The demand TNUoS tariff zones correspond to the original Regional Electricity Company (REC) franchise areas in England and Wales, and the geographical areas of the two Scottish electricity companies. These are depicted geographically in Figure A.1.3 against a backdrop of the 2009/10 national electricity transmission system.

General Interpretation

The geographic diagrams of the Use of System tariff zones provide an approximate indication of the geographical area of the tariff zones. Formally, it is only the transmission substations that are allocated to zones and the figures should not therefore be used to establish the zone of any particular town or village. A demand customer's zone is effectively determined by the Grid Supply Point (GSP) Group to which the customer is deemed to be connected. In the case of a directly-connected power station, the generation tariff zone applicable relates to the geographical location of the transmission substation (connection site) to which the station is connected. In the case of an embedded power station, the generation tariff zone applicable relates to the transmission substation to which that station is deemed connected. This would depend on the operating arrangements of the lower voltage distribution networks under the control of the local distribution Network Operator.

Table E.1.0 lists the 2009/10 maximum demand for each GSP and was introduced in Chapter 2 (Electricity Demand). The final column in the table also gives DCLF (Direct Current Load flow) Node information. This has been included to increase the transparency, particularly with regard to the use of NETS SYS data in the DCLF Transport model, which is used for calculating TNUoS tariffs. Whilst the information provided allows Users to identify the DCLF nodes at which LV demand is mapped, it is important to note that this additional information will not enable Users to replicate the demand data used in the DCLF model exactly. This is due to the treatment of Large embedded generation and station demand, which is not included in these figures.

SYS Boundaries and SYS Study Zones

SYS Boundaries

For the purpose of illustrating system performance, the need or otherwise for transmission reinforcement and for describing opportunities, it is useful to divide the system up and consider power transfers across certain critical boundaries. 17 such boundaries are used in this Statement (11 for England & Wales and 6 for Scotland).

The 17 boundaries are shown schematically/electrically in Figure A.2.4 for SHETL, Figure A.3.4 for SPT and Figure A.4.4 for NGET against the backdrop of the 2016/17 system and are listed in Table 6.1. The 17 boundaries are also shown in Figure A.1.6 against a geographic backdrop, which includes the 2009/10 system. These boundaries are used, amongst other things, to provide a clearer picture of the overall capability of the transmission system to transmit power, as described in Chapter 8 (Transmission System Capability).

SYS Study Zones

The areas of the system described by and/or encompassed by the 17 SYS boundaries are referred to as the SYS Study Zones. There are 17 such SYS Study Zones and these are listed in Table 6.2 and shown in Figure A.1.6 against a geographic backdrop, which also depicts the 2009/10 system.

Introduction to the National Electricity Transmission System

System Overview

By the end of 2009/10 the power system in Great Britain will be made up of all Large power stations, the 400kV and 275kV transmission system (and 132kV transmission system in Scotland) and 14 distribution systems.

The location of Large power stations is shown against a backdrop of the 2009/10 transmission system in Figure A.1.1. The 2009/10 national electricity transmission system is again depicted in Figure A.1.2, with the 400kV system shown in blue, the 275kV system in red and the 132kV system in black.

The national electricity transmission system includes:

- Overhead Lines
- Underground Cables
- Substations, i.e. transmission system facilities where voltage transformation or switching takes place
- Power transformers and Quadrature Boosters (QBs)
- Grid Supply Points, i.e. points where electrical supplies are provided to Users (Note: 132kV & 66kV are assumed to be Supply Voltages in England & Wales, but not in Scotland.)

The majority of Large power stations are directly connected to the national electricity transmission system. However, several Large power stations are embedded within the lower voltage distribution networks. Medium and Small power stations are currently all embedded within the distribution networks. Table 6.3 summarises the capacity of Large power stations by fuel type and quantity as at the winter peak of 2009/10. The capacity of Auxiliary Gas Turbines associated with the Large power stations are included.

Currently there are two HVDC External Interconnections linking the national electricity transmission system with External Systems. These are:

- Connecting converter stations at Sellindge in Kent and Les Mandarins near Calais in France; and
- Connecting converter stations at Auchencrosh in the south of the SPT system and Islandmagee in Northern Ireland.

Grid Supply transformers connect the national electricity transmission system with the distribution systems at 'Grid Supply Points', where bulk supplies of electricity are delivered to the Distribution Companies and Non-Embedded Customers. Electricity is then usually supplied to domestic, commercial and industrial customers through the distribution systems.

Benefits of an Interconnected Power System

Until the 1930's electricity supply in Great Britain was the responsibility of a multiplicity of private and municipally owned utilities, each operating largely in isolation. The Electricity Supply Act (1926) recognised that this was a wasteful duplication of resources. In particular, each authority had to install enough generating plant to cover the breakdown and maintenance of its generation. Once installed, it was necessary to run more plant than the expected demand to allow for possible sudden plant failure.

By interconnecting separate utilities with the high voltage transmission system, it is possible to pool both generation and demand, providing a number of economic and other benefits, including:

- An interconnected transmission system providing a more efficient bulk transfer of power from generation to demand centres.
- The interconnected transmission system, by linking together all participants across the transmission system, makes it is possible to select the cheapest generation available.
- Transmission circuits tend to be far more reliable than individual generating units, and enhanced security of supply is achieved because the transmission system is better able to exploit the diversity between individual generation sources and demand.
- An interconnected transmission system enables surplus generation capacity in one area to be used to cover shortfalls elsewhere on the system, resulting in lower requirements for additional installed generation capacity, to provide sufficient generation security for the whole system.
- Without transmission interconnection, each separate system would need to carry its own frequency response to meet demand variations, but with interconnection the net response requirement only needs to match the highest of the individual system requirements to cover for the largest potential loss of power (generation) rather than the sum of them all.

Transmission System Capability

Three factors can limit the capability of the transmission system to transfer power across a system boundary

- Thermal capability is the maximum amount of power that can be transferred across a boundary on the system without exceeding the thermal rating of any one of the individual circuits; it depends to a large degree on the way in which the power transfer is shared between them
- Voltage capability, because it is sometimes necessary to restrict power transfers to a level lower than the firm thermal capability to ensure satisfactory voltage levels in the importing area.
- Stability limits, because the power transfer between two areas or between a major generating station and the system can also be limited by considerations of electro-mechanical stability. Two stability regimes are usually defined:
    - Transient, after a severe disturbance, like a network fault.
    - Steady state, which concerns the response to small disturbances such as the normal random load fluctuations.

Transmission System Losses

The flow of power across the transmission system causes power losses in the various elements of the system. Most of these power losses are a function of the square of the current flowing through the circuit or transformer windings (I^2R) and cause unwanted but inevitable heating of transmission lines, cables and transformers. Since such losses are variable they are often referred to as the 'variable' power losses.

In addition there are unavoidable 'fixed' losses associated with overhead lines and transformers. The term 'fixed' losses however, is something of a misnomer. Relative to the 'variable' losses they are reasonably static, but they can and do vary. 'Fixed' losses on overhead transmission lines take the form of corona losses that are a function of voltage levels and weather conditions. Corona loss is the loss of power to the air and insulation surrounding high-voltage equipment and is generally visible in the dark as a luminous glow surrounding high-voltage conductors.

'Fixed' losses in a transformer take the form of iron losses. Iron losses occur in the iron core of the transformer when subjected to an alternating magnetic field and as such vary with the frequency of the power flow producing the alternating magnetic field. Iron losses are further sub divided into hysteresis and eddy current losses. It may be noted that the 'variable' transformer heating losses mentioned above are sometimes referred to as 'copper' losses in recognition of the material used for transformer windings. Thus transformers have 'variable' copper losses and 'fixed' iron losses.

An estimated breakdown of transmission power losses at the time of ACS peak demand is given under "Power Losses" in Chapter 7.

Impact of Generation Siting

Users can directly influence the need for major transmission reinforcements by their choice of where to site their new generating stations. For example, if a User sites a new station in an exporting area (i.e. where the amount of generation already exceeds the demand), the maximum power flow will increase and may exceed the firm transmission capacity of the existing system, thus precipitating the need for transmission reinforcement. The converse is, of course, also true.

Table 6.1 - SYS Boundaries		
Boundary Number	**Boundary Name**	**Licensee**
B1	North West Export	SHETL
B2	North-South	SHETL
B3	Sloy Export	SHETL
B4	SHETL-SPT	SHETL/SPT
B5	North-South	SPT
B6	SPT-NGET	SPT/NGET
B7	Upper North-North	NGET
B8	North to Midlands	NGET
B9	Midlands to South	NGET
B10	South Coast	NGET
B11	North East & Yorkshire	NGET
B12	South & South West	NGET
B13	South West	NGET
B14	London	NGET
B15	Thames Estuary	NGET
B16	North East, Trent & Yorkshire	NGET
B17	West Midlands	NGET

Table 6.2 - SYS Study Zones		
Zone Number	**Zone Name**	**Licensee**
Z1	North West (SHETL)	SHETL
Z2	North (SHETL)	SHETL
Z3	Sloy (SHETL)	SHETL
Z4	South (SHETL)	SHETL
Z5	North (SPT)	SPT
Z6	South (SPT)	SPT
Z7	North & NE England	NGET
Z8	Yorkshire	NGET
Z9	NW England & N Wales	NGET
Z10	Trent	NGET
Z11	Midlands	NGET
Z12	Anglia & Bucks	NGET
Z13	S Wales & Central England	NGET
Z14	London	NGET
Z15	Thames Estuary	NGET
Z16	Central S Coast	NGET
Z17	South West England	NGET

Table 6.3 - Summary of Power Stations 2009/10		
Fuel Type	**Number**	**Capacity (MW)**
Nuclear		
Magnox	2	1450
AGR	6	8244
PWR	1	1200
Sub Total	**9**	**10894**
Coal (+ AGT)		
Small Unit	2	783
Medium Unit	1	1102
Large Unit	11	20801
Sub Total	**14**	**22686**
CCGT	40	27591
CHP	9	2224
Sub Total	**49**	**29815**
Oil (+ AGT)	3	3636
OCGT	5	579
Sub Total	**8**	**4215**
Hydro	37	1129
Pumped Storage	4	2744
Sub Total	**41**	**3873**
Wind Offshore	2	800
Wind Onshore	43	1981
Sub Total	**45**	**2781**
Biomass	1	45
Sub Total	**1**	**45**
TOTAL	**167**	**74310**

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Chapter 7

Transmission System Performance

Introduction

Chapter 6 (The Transmission System) described the existing and planned transmission network in terms of its components and structure. This chapter describes the performance of the existing and planned transmission network in terms of:

(i) circuit capacities;

(ii) system power flows;

(iii) grid supply point loadings;

(iv) short circuit currents (single phase and three phase); and

(v) system and zonal power losses.

The reader is reminded that, as explained under "Scope" in Chapter 6 on the national electricity transmission system, the ‘SYS background’ does not necessarily contain all transmission reinforcement schemes which may in the event be required for compliance with the Licence Standard. Chapter 8 (Transmission System Capability) identifies only those reinforcement schemes judged to be necessary to ensure that the transmission system is compliant for the SYS background (see Table 8.2). Additional reinforcements to those in Table 8.2 may in the event also be required.

It is useful at this point to explain, in simple terms, the difference between circuit capacity, loading and boundary capability.

The capacity or rating of a circuit is the maximum loading which may be permitted to flow on that circuit under specific conditions (e.g. ambient/seasonal temperature).

The loading on a circuit is the actual or forecast power flow on that circuit resulting from a given set of conditions (e.g. the demand level and the generating plant used in meeting the demand).

The capability of a boundary is the maximum transfer across the boundary that can be tolerated for the particular background of demand and generation under consideration without breaching security criteria. This means that following ‘secured events’ such as fault outages of transmission circuits, there are, inter alia, no overloaded items of transmission equipment or unacceptable voltages, and all demand is supplied (save as permitted by specific demand connection criteria). The precise criteria are defined in Licence Standard, which is more fully referred to as the NETS Security and Quality of Supply Standard (NETS SQSS). Compliance with the standard is a condition of the Transmission Licence.

Circuit capacities and loadings are reported in this chapter. Boundary capabilities are reported in Chapter 8 (Transmission System Capability).

Again, as with the previous chapter, many of the figures discussed in this chapter have been included in Appendix A (Figures) and only referenced in the text.

Circuit Capacities

Table B.2.1a for SHETL, Table B.2.1b for SPT and Table B.2.1c for NGET show, amongst other things, the post fault continuous ratings (in MVA) of all the circuits of the main interconnected transmission system for each season of the year.

Bases of Power Flow Analyses

Overview

The power flows presented in this chapter are based on the SYS background and the Planned Transfer Condition.

The SYS background includes:

(a) the NGET 'Base' based forecast unrestricted ACS Peak Demand on the national electricity transmission System, which is given in Table 2.1 (row 7);

(b) generation selected from a ranking order based on the existing and proposed new generation for which an appropriate Bilateral Agreement is in place. This generation is presented and discussed in Chapter 3. The techniques for selecting which generation is used to meet the demand are described below; and

(c) the existing transmission network and those planned future transmission developments which have been technically and financially sanctioned by the relevant Transmission Licensee. This is described in Chapter 6.

The demand forecasts used in the power flow analyses include transmission losses (see "ACS Peak Demand" in Chapter 2). For the purpose of illustrating the general power flows throughout the system, these losses are effectively apportioned uniformly across Grid Supply Points through the application of the correction factor described under "Customer Demand Data" in Chapter 2). However, where greater accuracy is required for determining the need for local transmission reinforcements, we would more accurately calculate the losses particular to that local zone.

The forecast unrestricted ACS Peak Demand given in Table 2.1 is presented on several bases and it is clearly important that the appropriate basis is selected for use in power flow analyses. The demand stream given in rwo 3 treats exports from Scotland to Northern Ireland across the Moyle interconnection as demand and is also net of station demand. This latter point recognises that the value of power station TEC is used for power system analyses. TEC is net of any auxiliary demand supplied through the station transformers (station demand) and, consequently, the ACS Peak Demand used is also net of station demand.

Please note, however, that for the presentational purposes of the generation ranking order of operation given in Table F.4 in Appendix F, which is presented and discussed later in this chapter, exports across the Moyle interconnector have been treated as negative generation. This is compatible with the demand stream given in line 7 of Table 2.1, which also is net of station demand.

For illustrative purposes, a useful reference system condition on which to base studies is the Planned Transfer Condition. The Planned Transfer Condition is defined in the Licence Standard. The following paragraphs outline how the techniques for modelling the Planned Transfer, which are set out in the Licence Standard, have been applied for the purposes of this Statement.

Modelling of the Planned Transfer Condition

Appendix C of the Licence Standard sets out how the Planned Transfer Condition should be modelled. For this purpose, two techniques are described, namely: the Ranking Order

Technique (to be applied when the plant margin exceeds 20%); and the Straight Scaling Technique (to be applied when the plant margin is 20% or less).

It should be noted, however, that the License Standard definition of Plant Margin differs from the definition given in Chapter 5, which is used for the more general purposes of this Statement.

The Licence Standard (i.e. the National Electricity Transmission System “Security and Quality of Supply Standard”) definition of Plant Margin is:

> "The amount by which the total installed capacity of directly connected Power Stations and embedded Large Power Stations exceeds the net amount of the ACS Peak Demand minus the total imports from External Systems. This is often expressed as a percentage (e.g. 20%) or as a decimal fraction (e.g. 0.2) of the net amount of the ACS Peak Demand minus the total imports from External Systems".

The basic difference between the two definitions lies in the fact that, the Licence Standard definition treats imports as negative demand but the SYS definition, used in Chapter 5, treats imports as generation. Whilst the Plant Margin in MW terms remains the same, in percentage terms the SYS margins are lower than would be the case using the Licence Standard definition. Please note that, whilst the wording of the SYS definition of Plant Margin does not mention exports to External Systems, it is implicit that such exports should be treated as positive demand.

The overall process for modelling the planned transfer may be regarded as being made up of the following three parts, the first two of which concern the ranking order technique and the third is obviously concerned with the straight scaling technique. The three parts are:

- Ranking the relevant generating units in order of their relative likelihood of operation at peak;
- Identifying which plant is most likely to be contributing towards meeting the peak demand; and finally
- Applying the straight scaling technique.

Ranking Plant in Order of Likelihood of Operation at Peak

This part of the process can be further subdivided into:

- treatment of imports and exports across External Interconnections;
- ordering (i.e. placing the generating units into a ranking order of likely operation); and

External Interconnections:

Table 3.12 in Chapter 3 (Generation) sets out the notional import and export capabilities across the External Interconnections at the time of our ACS Peak Demand. For the purpose of evaluating plant margins, import capabilities across External Interconnections are treated as generation and exports are treated as demand. This is explained in Chapter 5 (Plant Margin).

However, when ranking generating plant in order of likelihood of operation at peak, the level of imports and exports across External Interconnections is subject to special treatment. That treatment recognizes that, notwithstanding the export capability (as expressed in Table 3.12), the expected actual level of exports and imports is, itself, a function of the prevailing plant/demand balance.

In brief, the methodology employed is to first calculate the margin of installed generation over demand without imports or exports across the Cross Channel Link or the Netherlands Interconnector for the peak of each year. The resultant margin is then used to determine an assumed level of imports or exports across these two Interconnectors for the peak of each year. For margins up to and including a nominal 25%, the full import capability is assumed. For margins of 45% or over, the full export capability is assumed. For margins between 25% and 45% a linear reduction in exports/increase in imports is assumed such that, at a margin of 35%, there are no imports or exports across the Cross Channel Link or the Netherlands Interconnector.

Throughout this methodology, export to Northern Ireland and Eire is represented as negative generation in the generation ranking order of operation presented in Table F.4. This approach differs from the methodology used to evaluate Plant Margins which, amongst other things, treats imports as positive generation and exports as positive demand in accordance with the definition of Plant Margin.

A particular result of the application of the above methodology is that, for the purpose of ranking plant in order of likelihood of operation at peak, there may be exports (rather than imports based on nominal capabilities) to France and the Netherlands at peak, the level of which would be a function of the prevailing plant/demand balance.

Ordering:

A list is compiled of all relevant generating units in the "SYS Background". The level of imports and/or exports across External Interconnections as derived from application of the methodology outlined in the previous section, are added to the list.

The term Transmission Entry Capacity (TEC) is defined and used solely on a power station basis and does not exist on a generating unit basis. In view of this, each generating unit on the list is attributed with the appropriate Registered Capacity (RC) and each power station is attributed with the appropriate TEC, correct as at the "data freeze date".

All generating units, imports and/or exports are then arranged in order of their perceived likelihood of operation at the time of the ACS Peak Demand.

Future plant is likely to achieve a relatively high ranking given that it likely to be modern and efficient unless the particular plant is designed to operate at base load only. New generation is ranked according to plant type, with offshore wind at the highest rank, followed by wave/tidal, and nuclear above existing plants. Other new plants are onshore wind, biomass plants and new CCGTs, all of which are ranked relatively high, in between tranches of existing hydro generation, wind and nuclear.

For existing generation, this is achieved by inspection of the unit operation experienced over previous winter periods, which are taken as being from the beginning of December to the end of January. In general, if the unit operated at the daily peak, it is attribute a score of "1" whether operated at full or part load. If the unit did not operate, it is attributed a score of "0". Scores for each unit are then aggregated to give the "probability of running" for each unit. A high probability of running would mean that the relevant unit is ranked as having a high likelihood of operation over the coming winter peaks and vice versa.

However, the above represents a general rule and, rather than strict adherence, the rule is applied in a pragmatic way. That is, the results of its application are tempered by judgement based market intelligence. Accordingly, a particular plant with a low score may be moved up the ranking if market intelligence suggests this to be the more likely outcome or vice versa.

Identification of Contributory and Non - Contributory Plant

This part of the process is concerned with identifying that generating plant which is most likely to operate at the time of system peak in a climate where plant margins exceed 20%.

For analysing the performance of the transmission system at the time of winter peak, the load factor over the winter peak period becomes relevant. Experience shows that this is in the region of 90% and 36% for conventional and wind based generation respectively. These figures translate into assumed winter peak availabilities of 100% and 40% for conventional and wind based generation capacity respectively.

Accordingly, in establishing which plant, in the ranking order of Table F.4, is to be regarded in this Statement as contributory and which is to be regarded non-contributory, the cumulative system generation capacity to be compared with demand in the calculation of plant margin has been taken as 100% of the capacity of each conventional generator and 40% of that of each wind farm.

The lower ranking plant in the ranking order is then progressively removed and treated as non-contributory, until a Plant Margin of just 20% is achieved. It is worth reiterating that the Plant Margin referred to is as defined for the purpose of the Licence Standard.

The result of the above ranking order technique, which is used only if the plant margin exceeds 20%, is a list of contributory plant, with unit outputs, which sum to equal 120% of (unrestricted "ACS Peak Demand" less Station Demand). The full capacities of all the contributory generation is used as the initial basis for system studies.

Application of the Straight Scaling Technique

The straight scaling technique is applied when the plant margin, as defined in the Licence Standard, is equal to or less than (although still positive) 20%. Accordingly, the straight scaling technique is applied following application of the ranking order technique or otherwise straight away when the plant margin is already 20% or less.

The straight scaling technique, which is set out in the Licence Standard, involves the application of scaling factors ‘A’ and ‘S’. The ‘A factors’ relate to the expected availability of each generating plant type at the time of the peak. The ‘S factors’ relate to the ratio between the system demand to be met and the total generation capacity available. Under the technique, the generation output, for study purposes, of all contributory plant is calculated for the ‘planned transfer condition’ by applying 'A' and 'S' scaling factors to their capacities such that the aggregate effective generation of all contributory plant is equal to the forecast peak demand plus transmission losses less imports from external systems.

In recognition of their different characteristics and use, specific values of the ‘A factors’, which relate to expected generating plant availability, defined in the Licence Standard may be used for thermal, hydro and wind generation. The values are chosen in order that the ‘required transfer capability’ , which is simply the sum of the ‘planned transfer’ and the appropriate ‘interconnection allowance’, will represent approximately the same percentile of the actual distribution of power transfers at time of peak demand whether the background includes wind or hydro generation or not. In the power system analyses, which underlie the power flows and capabilities presented in this Statement, the following values were used: 100% for thermal; 100% for hydro; and 72% for wind.

Imports from External Systems are not subject to scaling. According to the Licence Standard definition of Plant Margin, imports from External Systems are deducted from the demand to be met and Exports to External Systems form part of the demand to be met.

Overview of Main Power Flows at Peak

Power flows on the SHETL network for each of the seven years from 2010/11 to 2016/17 are illustrated in the following series of figures: Figure C.1.1; Figure C.1.2; Figure C.1.3; Figure C.1.4; Figure C.1.5; Figure C.1.6; and Figure C.1.7.

Power flows on the SPT network for each of the seven years from 2010/11to 2016/17 are illustrated in the following series of figures: Figure C.2.1; Figure C.2.2; Figure C.2.3; Figure C.2.4; Figure C.2.5; Figure C.2.6 and Figure C.2.7.

Power flows on the NGET network for each of the seven years from 2010/11 to 2016/17 are illustrated in the following series of figures: C.3.1; Figure C.3.2; Figure C.3.3; Figure C.3.4; Figure C.3.5; Figure C.3.6 and Figure C.3.7.

While the complex power flow program used computes nodal voltage, phase angles and both real and reactive power flows on the system only the real (MW) power flows have been displayed on the figures, both for ease of presentation and for clarity.

The requirements placed on the transmission system depend on the size and geographical/ system location of generation and demand.

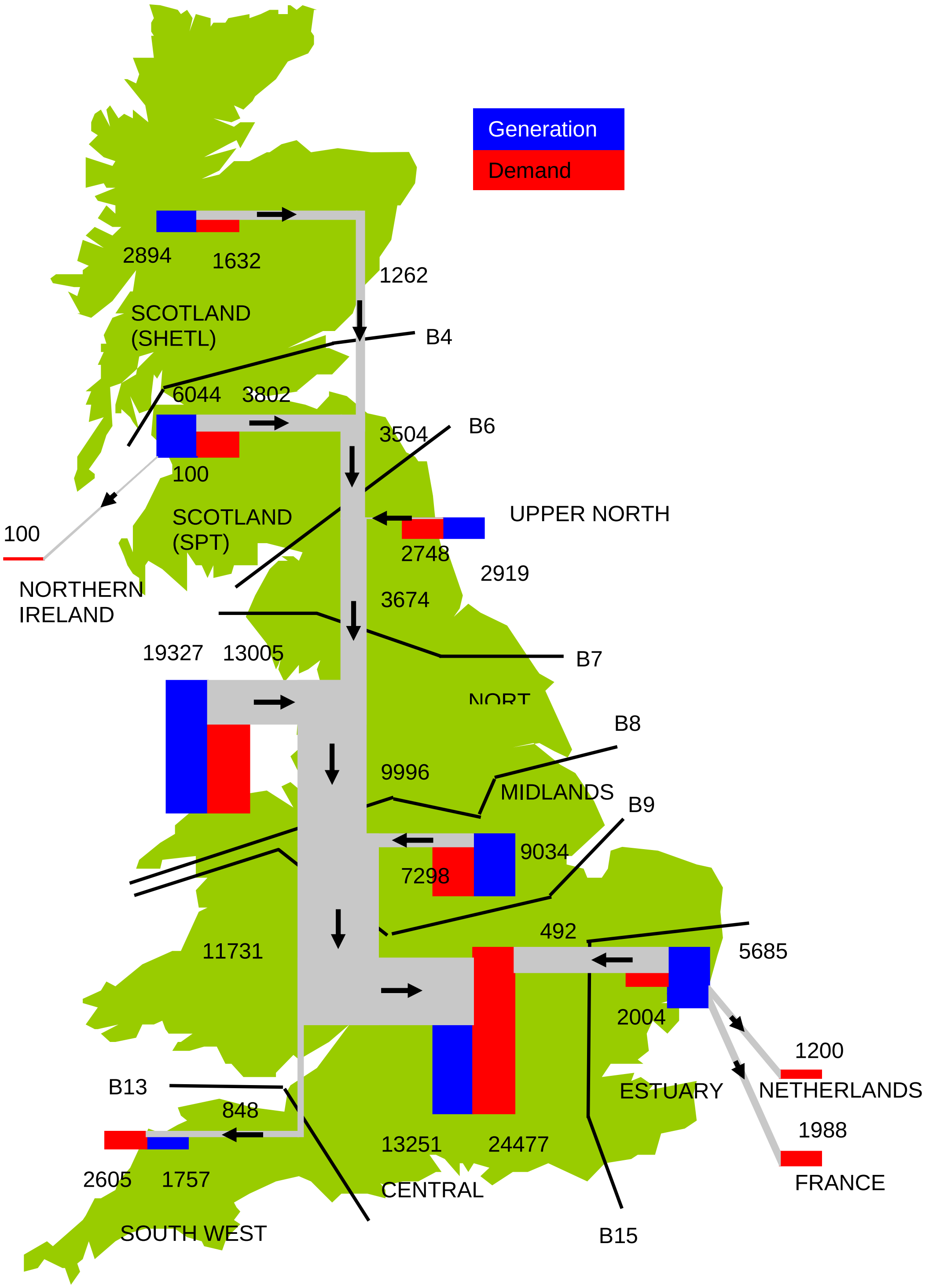
The section on "SYS Boundaries and SYS Study Zones" in Chapter 6 introduced the 17 SYS boundaries which are used for the purpose of illustrating system performance, illustrating the need or otherwise for transmission system reinforcement and for describing opportunities. These boundaries encompass the 17 SYS Study Zones.

Table 7.1 and Table 7.2 summarise the Planned Transfers, under the SYS background, for each of the 17 SYS Study Zones and across each of the 17 SYS boundaries respectively. Please note that, unlike the generation ranking order of Table F.4 which treats the exports from Scotland to Northern Ireland across the Moyle interconnector as negative generation, Table 7.1 and Table 7.2 treat such exports as demand, which is in line with Table 2.1 of Chapter 2 (Electricity Demand).

There is a slight difference in the values of summated demand, which appear towards the foot of Table 7.1 compared with the demand forecast of row 7 of Table 2.1. This is due to the fact that the system losses included in the forecasts of Table 2.1 reflect estimates made at the time of formulating the forecasts whereas Tables 7.1 and 7.2 (and the power flow analyses presented in this chapter) include calculated system losses derived from the system analyses. In general terms, the disposition of demand and generation across the national electricitytransmission system is such that much of the generation capacity is located in or towards the northern parts of the system while much of the demand is located in the southern parts of the system. As a consequence, the resultant power broadly flows from the northern parts to the southern parts of the system, particularly at times of the system peak.

The capacity of transmission contracted generation is reported to rise in over the period 2009/10 to 2016/17 (Table 3.5 refers). Amongst other things, "Generation Disposition" in Chapter 3 described the disposition of this future plant. However, these figures do not include the prospective growth of embedded generation; particularly in wind farms. This receives some consideration in Chapter 4 (Embedded and Renewable Generation).
The year on year fluctuations in planned transfer, displayed in Table 7.1 and Table 7.2, are not only a function of changes in demand and installed generation disposition, but also of the changing contributory plant disposition. The section on "Generation Disposition" in Chapter 3 reports that, the forecast disposition of contributory generation and ACS demand across the system is such that, against the SYS background, the high power transfers at times of peak demand from the, northern parts of the system to the southern parts, are expected to persist.

Figure 7.1 - ACS Power Flow Pattern for 2010/11



The Thames Estuary boundary transfer appears relatively small, however this is due to much of the local generation supplying the continental export. In the case of continental import, the local generation and import combine to give a significant export out of the Thames estuary.

Figure 7.1 and Figure 7.2 illustrate the broad power flow pattern for 2010/11 and 2016/17 respectively. The capability of the national electricity transmission system to transport these levels of power transfer across system boundaries is the subject of Chapter 8 (Transmission System Capability). Amongst other things, that chapter explains that in considering boundary transfers and capabilities and the possible need for additional reinforcement it is important to take account of the requirements of the planning criteria in the Licence Standard. In particular, planning criteria relating to the main interconnected transmission system require that a margin for security (i.e. the interconnection allowance) should be allowed for.

The outturn power flows at the peak of any year may differ from those given in Table 7.1, Table 7.2, Figure 7.1, Figure 7.2, and the series of figures included in Appendix C for a number of reasons. These include:

- the generation capacity and location may easily differ due to the decommissioning of plant, the addition of new plant, transmission contracted plant not being constructed, the non availability of particular generating units and of course a different ranking order of operation being used;

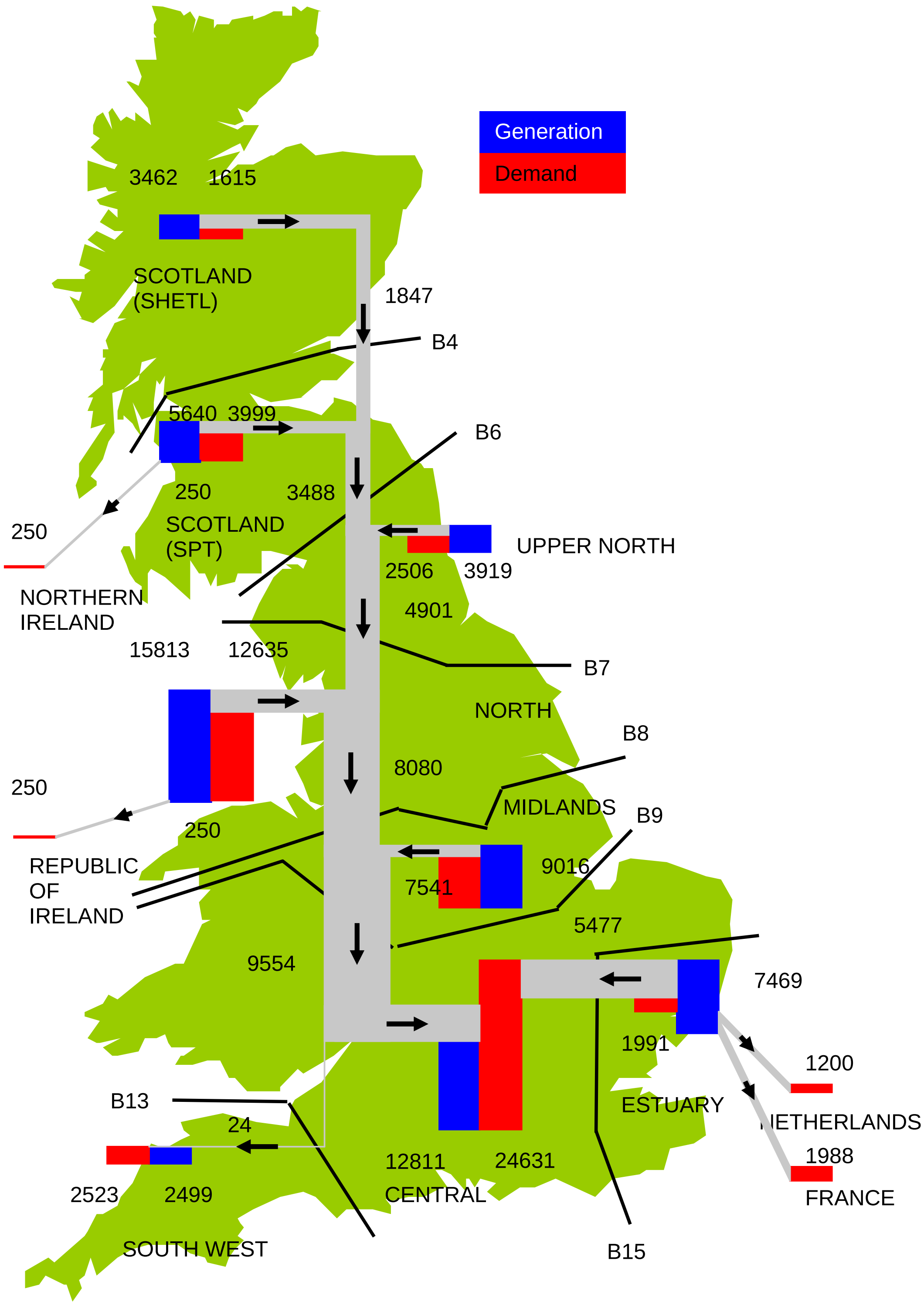
- the demand level and disposition may differ from that forecast. The level may easily differ by ± 1GW (± 2%) due to the temperature on the day of peak differing from that of Average Cold Spell;

- the unplanned (fault) outage of transmission circuits. A number of supergrid circuits may be out of service at any given time due to fault breakdown. Power flows in the neighbourhood of such circuit outages may be markedly affected; and

- the planned outage of transmission circuits for urgent maintenance, although such outages are more likely to be arranged for the summer months when demand and circuit loadings are lower.

There are clearly a great many variables, which will influence the outturn power flow. However, whilst the power flows displayed in the various tables and figures of this chapter may not be experienced in practice, they are nevertheless indicative of the flows to be expected under the SYS background. Power flows, transmission capabilities and the possible need for further transmission reinforcement based on our current view of a more likely outturn than the SYS background are discussed in Chapter 8 (National Electricity Transmission System Capability).

Figure 7.2 - ACS Power Flow Pattern for 2016/17



Off-Peak Power Flows

At off-peak times less generation capacity is needed to meet the reduced demand and only the higher plant in the ranking order is used within the limits of system constraints. Thus the power flows around the system and circuit loadings not only change as a result of the lower demand levels but also because of the changes in the contributory generation disposition.

Transmission circuit thermal ratings reduce outside the winter period and, in addition, the system may become depleted due to transmission circuits and generation units being taken out of service for planned maintenance and other reasons. Maintenance practices on our system generally results in a boundary made up of about eight circuits being continuously depleted by one or other of its circuits between the months of April and October.

The net result is that both circuit loadings and boundary capabilities will vary at off-peak times according to prevailing conditions. They may be either higher or lower relative to the peak period. In view of the many variables associated with the real-time operation of the system, it is not a worthwhile exercise to present a rigorous analysis of possible future off-peak power flows and capabilities in this Statement.

In the real time phase of operation the system is managed such that it complies with the operational criteria in our Licence Standard. In applying this standard, which is aimed at ensuring the required level of security and quality of supply, prevailing conditions are taken into account. Power transfers around the system are managed such that, amongst other things, circuit loadings would remain within their rating and boundary transfers within their capability and no unacceptable conditions will arise even with specified circuit fault outages on top of any maintenance outages.

Grid Supply Point Loading

It was explained in "Demand on the Grid Supply Points" in Chapter 2 that Grid Supply Points (GSPs) are the points of connection between the national electricity transmission system, distribution networks, Large power stations and other Non-Embedded Customers where we deliver electricity.

The loading on a GSP is the demand on the lower voltage (LV) side less the output of any Large power station connected to the LV side or embedded within the distribution system fed from that point. An allowance for the output from embedded Medium and Small power stations is already included in the users' demand estimates as explained in "Customer Demand Data" in Chapter 2.

For the SYS background, the GSP net loading is the difference between the flows into and out of that GSP. Such power flows are shown in the series of power flow figures included in Appendix C. This GSP loading is net of any generation at that point. A more direct and detailed indication of GSP loading at maximum demand is given in the series of tables presented in Appendix E.

It was also explained in "Customer Demand Data" in Chapter 2 that, for infrastructure planning, the demand at the time of the system peak is used. These forecasts of demand at the time of system peak underlie the customer based demand forecast of Table 2.1 and the series of power flow figures included in Appendix C. For GSP planning, the demand at the GSP peak is more appropriate. This demand is used, together with appropriate allowances for embedded Large power stations, in the application of the criteria for design of demand connections in the Licence Standard.

Short Circuit Currents

Engineering Recommendation G74 defines a computer based method for the calculation of short circuit currents and has been registered under the Restrictive Trade Practices Act (1976) by the Energy Networks Association (ENA), formerly the Electricity Association, and the associated Statutory Instrument has been signed to this effect.

Three phase to earth and single phase to earth short circuit current analyses have been conducted by each Transmission Licensee (SHETL, SPT and NGET), in respect of their own Transmission Areas, in accordance with ER G74. The series of tables presented in Appendix D, list the results of these analyses. To assist the reader in understanding the results, the next section of this chapter explains some of the salient points relating to the short circuit calculations including assumptions made and terminology used.

Tables B.6a to B.6c list the types of circuit breakers currently found at SHETL, SPT and NGET substations respectively together with their ratings (the NGET ratings are given for 400kV and 275kV voltage levels only). From this list it can be seen that several substations have a mixture of circuit breakers installed and this results in a range of ratings for those substations. Generally the substation infrastructure will have a similar rating to the associated circuit breaker.

The listed ratings should be regarded as indicative and therefore used as a general guide only. If customers require more detailed information relating to specific sites they may contact us as described in "Further Information" in Chapter 1.

Furthermore, although the short circuit duties at a node may at times exceed the rating of the installed switchgear, the switchgear may still not be overstressed for one or more of the following reasons:

- the topology of the substation is such that the switchgear is not subjected to the full fault current from all of the infeeds connected to that node. This is the case for feeder/transformer circuit breakers and mesh circuit breakers under normal operating conditions;

- switchgear is only subjected to excessive fault current when sections of busbar are unselected. This is the case for busbar coupler/section circuit breakers. On these occasions the substation can usually be temporarily re-switched or segregated to reduce the fault level; or

- re-certification of switchgear or modifications to its system is already in hand that will remove the overstressing.

Finally, please also note that, as explained in "Network Parameters" in Chapter 6, substation running arrangements are subject to variation. The running arrangements used for determining the short circuit currents presented in Appendix D may, in some cases, differ slightly from those presented elsewhere in this Statement.

Engineering Recommendation G74

International Standard IEC909, "Short-Circuit Current Calculation In Three Phase AC Systems" was issued in 1988 and has subsequently been published as British Standard BS7639. When IEC909 was issued the Electricity Supply Industry had no standard method or uniform methodology for fault level calculation. The hand calculation methodology detailed in IEC909 was considered conservative for the UK supply system and it was believed that its application could lead to excessive investment. In consideration of this potential excessive investment, an industry wide working group was established in 1990 to define "good industry practice" for the calculation of short circuit currents.

The resulting document, Engineering Recommendation G74 (ER G74), defines a computer based method for calculation of short circuit currents which is more accurate than the methodology detailed in IEC909 and, as a consequence, potential capital investment is more accurately identified. As previously mentioned, ER G74 has been registered under the

Restrictive Trade Practices Act (1976) by the ENA and the associated Statutory Instrument has been signed to this effect.

Short Circuit Current Calculation

Sophisticated computer programs are used for the purpose of conducting short circuit current analyses. Each analysis is based on an initial condition from an AC load flow and is carried out in accordance with ER G74. The broad calculation methodology is summarised in the following paragraphs.

When assessing the duties associated with busbars, bus section/coupler circuit breakers and elements of mesh infrastructure, it is assumed that all connected circuits contribute to the fault. When assessing the duties associated with individual feeder/transformer circuits it is assumed that the fault occurs on the circuit side of the circuit breaker with the remote ends of the circuit open. These represent the most onerous conditions.

Short-circuit currents are calculated using a full representation of the national electricity transmission network. Directly-connected and Large embedded generating units are also discretely represented with their electrical parameters based on data provided by the owner of the generating unit. Other Network Operators' networks are represented by network equivalents at the interface between the national electricity transmission system and the Network Operator's network. For example, a DNO network connected to a 132kV busbar supplied by SGTs will usually be represented by a single network equivalent in the positive phase sequence (PPS) and zero phase sequence (ZPS) networks. The use of network equivalents allows short-circuit currents in the national electricity transmission system to be calculated with acceptable accuracy and provides a good indication of the magnitude of the short-circuit currents at interface substations. Short-circuit currents quoted in Tables D.1.1 to D.3.7 for interface substations are not, however, suitable for specifying short-circuit requirements for new switchgear at the interface substations. These will need to be agreed between the relevant Transmission Licensee and the Network Operator on a site specific basis.

Short Circuit Current Terminology

The short circuit current is made up of an AC component with a relatively slow decay rate as shown in Figure 7.5 and a DC component with a faster decay rate as shown in Figure 7.6. These combine into the waveform shown in Figure 7.7. The waveform in Figure 7.7 represents worst case asymmetry and as such will be infrequently realised in practice.

Figure 7.5 - AC Component of Short Circuit Current

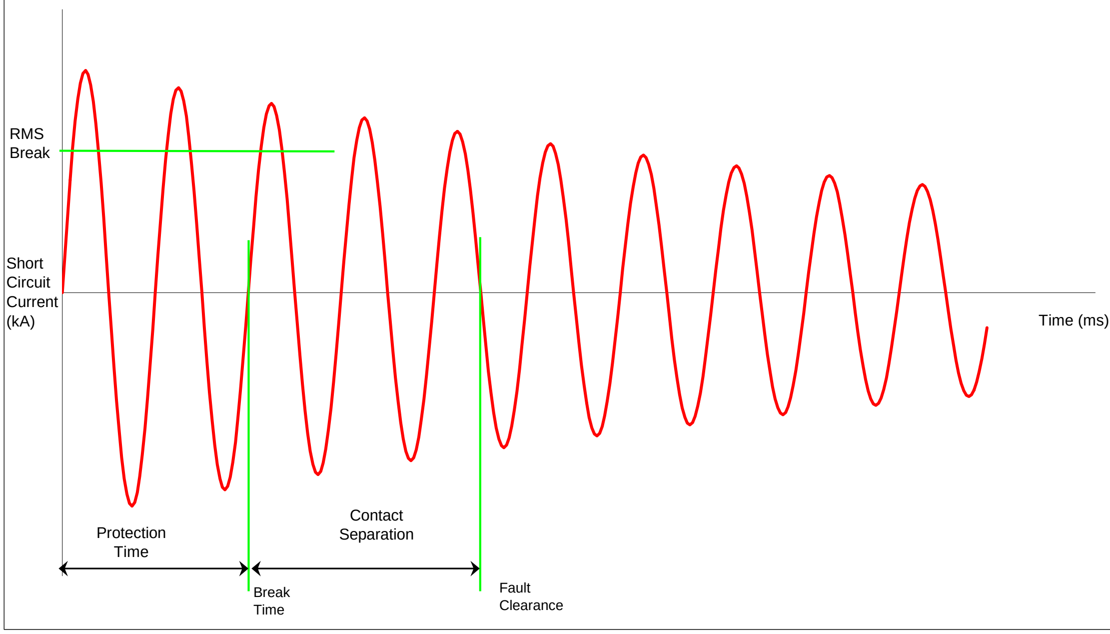
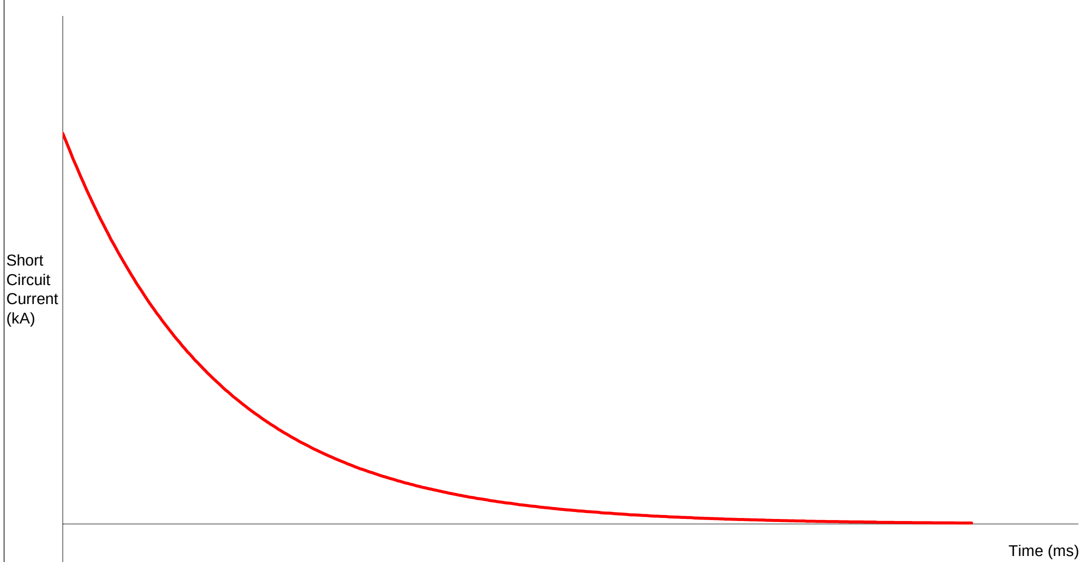


Figure 7.6 - DC Component of Short Circuit Current



X/R Ratio

The DC component decays exponentially according to a time constant which is a function of the X/R ratio. This is the ratio of reactances to resistances in the current paths feeding the fault. High X/R ratios mean that the DC component decays more slowly.

DC Component

The DC component of the peak make and peak break short-circuit currents are calculated from two equivalent system X/R ratios. An initial X/R ratio is used to calculate the peak make current, and a break X/R ratio is used to calculate the peak break current. Calculation of the initial and break X/R ratios is undertaken in accordance with IEC 60909-0 (2001-07) Method C (also known as the equivalent frequency method). We consider the equivalent frequency method to be the most appropriate general purpose method for calculating DC short-circuit currents in the national electricity transmission network.

The DC component of short-circuit current is calculated on the basis that full asymmetry occurs on the faulted phase for a single phase to earth fault or on one of the phases for a three phase to earth fault.

Making Duties

The making duty on bus section/bus coupler breakers is that imposed when they are used to energise an unselected section of busbar which is either faulted or earthed for maintenance. Substation infrastructure such as busbars, supporting structures, flexible connections, conductors, current transformers, wall bushings and disconnectors must also be capable of withstanding this duty.

The making duty on individual circuits is that imposed when they are used to energise a circuit which is either faulted or earthed for maintenance. This encompasses the persistent fault condition associated with Delayed Auto-Reclose (DAR) operation.

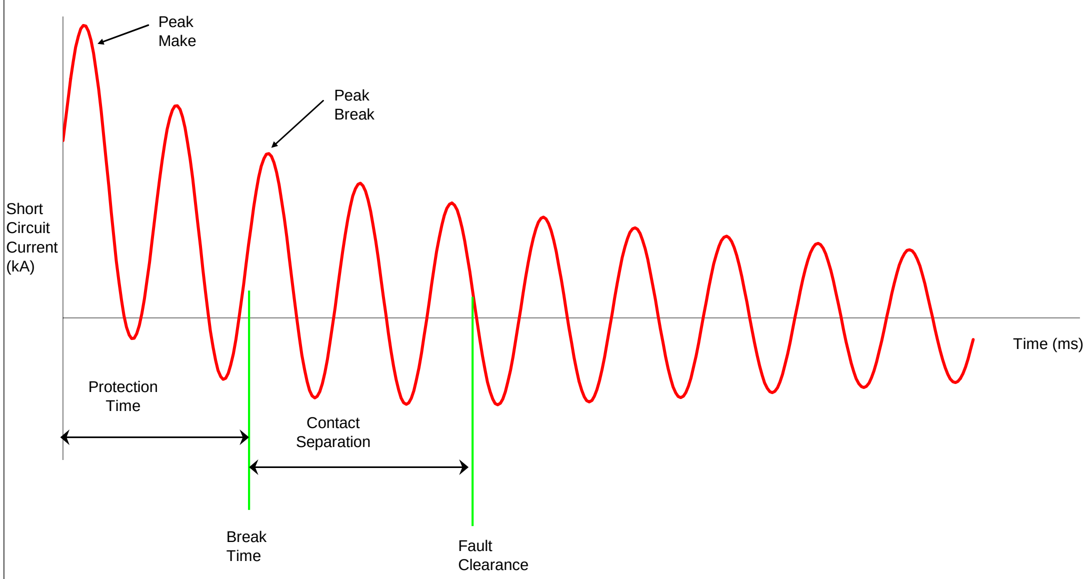
Breaking Duties

Bus section/coupler breakers are required to break the fault current associated with infeeds from all connected circuits if a fault occurs on an uncommitted section of busbar. Circuit breakers associated with a feeder/transformer or a mesh corner are required to break the fault current on the basis that the circuit breaker is the last circuit breaker to open clearing the fault. Circuit breakers associated with faulted circuits are required to interrupt fault current in order to safeguard system stability, prevent damage to plant and maintain security and quality of supply.

Initial Peak Current

In Figure 7.7, both the AC and DC components are decaying and the first peak will be the largest and occurs at about 10ms after the fault occurrence. This is the short circuit current that circuit breakers must be able to close onto in the event that they are used to energise a fault, hence this duty is known as the Peak Make. However, this name is slightly misleading because this peak also occurs during spontaneous faults. All equipment in the fault current path will be subjected to the Peak Make duty during faults and should therefore be rated to withstand this current. The Peak Make duty is an instantaneous value.

Figure 7.7 - Resultant Short Circuit Current



RMS Break Current

This is the RMS value of the AC component of the short circuit current at the time the circuit breaker contacts separate (see Figure 7.5), and does not include the effect of the DC component of the short circuit current.

DC Break Current

This is the value of the DC component of the short-circuit current at the time the circuit breaker contacts separate (see Figure 7.6).

Peak Break

As both the AC and DC components are decaying, the first peak after contact separation will be the largest during the arcing period. This is the highest instantaneous short circuit current that the circuit breaker has to extinguish, hence this duty is known as the Peak Break. This duty will be considerably higher than the RMS Break because, like the Peak Make duty, it is an instantaneous value (therefore multiplied by the square-root of 2) and also includes the DC component.

Choice of Break Time

The RMS Break and Peak Break will of course be dependent on the break time. The slower the protection, the later the break time and the more the AC and DC components will have decayed. For the purposes of this Statement a uniform break time of 50ms has been applied at all sites. For the majority of our circuit breakers, this is a fair or pessimistic assumption. In this context it should be noted that the break time of 50ms is the time to the first major peak in the arcing period, rather than the time to arc extinction.

Data Requirements

Generator Infeed Data

All generating units of directly connected Large power stations are individually modelled together with the associated generator transformers. Units are represented in terms of their Positive Phase Sequence (PPS) sub transient and transient reactances (submitted under the provision of Grid Code), as well as the DC stator resistances and Negative Phase Sequence (NPS) reactances (neither of these data items are submitted under the Grid Code but the stator resistance value is currently derived or assumed from historic records and the NPS reactance is calculated as the average of the relevant PPS sub transient reactances ($(X_d'' + X_q'')/2$). Fault level studies for planning purposes are carried out under maximum plant conditions (i.e. with all Large power stations included whether contributory or not) to simulate the most onerous possible scenario for a future generation pattern.

Auxiliary System Infeed Data

The induction motor fault infeed from the station board is modelled at the busbar associated with the station transformer connection. Where sufficient information is not available, it has been assumed that Auxiliary Gas Turbines are connected to the station boards as well as to the main generating units in order to simulate the most onerous condition. Where the X/R Ratio has not been provided, a value of 10 has been assumed.

Where the information is available, the fault infeed from the unit board, due to induction motors and auxiliary gas turbines, is modelled as an adjustment to the main genset substransient reactance. A more detailed model of the power station system may have to be used to assess fault levels when station and unit boards are interconnected.

GSP Infeed Data

Infeed data for induction motors and synchronous machines at GSPs is submitted by Users under the provision of the Grid Code. Infeeds from induction motors and synchronous machines are modelled as equivalent lumped impedances at the GSP.

Where the information is not available, 1MVA of fault infeed per MVA of substation demand, with an X/R ratio of 2.76 is assumed for all induction motors in the absence of more detailed data. This is in line with the requirements of ER G74.

Where more detailed fault level studies are required at 132kV or below, the associated system should be modelled in detail down to individual Bulk Supply Points (BSP's). Induction motor infeeds should then be modelled at these BSP busbars.

LV System Modelling

Where interconnections exist between GSP’s, these equivalents take the form of PPS impedances between those GSP’s. The ZPS networks take the form of minimum ZPS values modelled as shunts at the GSP busbars.

Where interconnections to other GSP’s do not exist, the equivalents take the form of equivalent LV susceptances modelled as shunts at the GSP busbar. The ZPS networks are modelled as shunt minimum ZPS values at the GSP busbars.

The values of PPS impedances between GSP’s shunt LV susceptances and shunt ZPS minimum impedances are as submitted by the Users under the provision of the Grid Code.

Power Losses

The following information on system power losses and zonal power losses is indicative only and is included to provide an insight into the level and type of power loss which may be expected around the system at the time of system ACS peak and against the SYS background only. At other times and/or against other backgrounds different levels of power loss may arise.

System Power Losses

An estimate of the level of system power loss occurring at the time of the ACS Peak Demand for the years 2010/11 to 2016/17 against the SYS background is given in Table 7.3. The losses shown are those incurred on the system between the power station generating unit and the grid supply points and are made up of:

- ‘Variable’ (I^2R) transmission heating losses in the overhead lines, underground cables and other equipment on our transmission system but excluding grid supply transformers at the GSPs;
- ‘Fixed’ losses made up of corona losses on outdoor transmission equipment and iron losses in transformers;
- ‘Variable’ (I^2R) heating losses (copper losses) in grid supply transformers at the GSPs; and
- ‘Variable’ (I^2R) heating losses (copper losses) in generator transformers.

It is stressed that the losses shown in Table 7.3 are indicative only. They correspond to the time of ACS Peak Demand and have been evaluated against the ‘SYS background’. The ‘fixed’ losses, like the ‘variable’ losses, can also vary to a certain extent. Accordingly, the exact losses on the day can vary for a number of reasons including:

- the outturn demand and/or in-merit generation pattern being different resulting in changed power flows and consequential changes to the variable losses which are a function of the square of the power flow (I^2R); and
- weather conditions being more or less adverse than forecast. For example if ‘heavy rain’ or ‘wet snow’ prevails across Great Britain then the so called ‘fixed’ losses (e.g. corona) could be some 100MW or more higher.

Total system power losses are shown in line 4 of Table 7.3 and these have also been expressed as a percentage (line 6) of the NGET ‘Base’ forecast ACS peak demand stream given in Table 2.1, less station demand, transmission losses and exports to external systems. The NGET ‘Base’ demand forecast given in Chapter 2 reflects the demand seen at the metering points at the power stations and accordingly includes both transmission and distribution system losses. As some metering is on the high voltage side of the generator transformers and some on the low voltage side, generator transformer copper losses are only partially taken into account.

Please note that there is a slight difference between the value of forecast ACS peak demand including losses given in Table 7.3 (i.e. row 4 plus row 5) and that given in line 7 of Table 2.1. This is due to the fact that the system losses included in the forecasts of Table 2.1 reflect estimates made at the time of formulating the forecasts whereas Table 7.3 includes calculated system losses derived from system analyses.

The transmission heating losses (line 1) are a function of the power flow pattern around the system. Fixed losses (line 2) are fairly constant over the period. Please note that values provided for fixed losses are estimated based on reasonable growth from last year’s values. Grid Supply transformer heating losses (line 3) display a modest increase over the period in step with the growth in forecast ACS Peak Demand (line 5).

Less significant perturbations, perhaps not obvious in the results displayed in the table, are caused by a number of factors including: increased transmission capacity (through reinforcement rather than reprofiling) which reduces transmission heating losses; or embedded large power stations closing, decommissioning or otherwise becoming non-contributory which can increase grid supply transformer heating losses.

The heating losses on generator transformers are also given in line 7 of Table 7.3. Although not included in the total for transmission losses, they are provided for information. It can be ssen from Table 7.3, that Generator Transformers heating losses display a modest increase over the period.

Zonal Power Losses

Amongst other things, the commissioning and operation of a new power station will have an effect on transmission losses and this will be a function of its system location and the prevailing power flows at the time.

Clearly, if a new power station were to be located in the north, and this were to displace the operation of southern generation, then the north to south power flows would increase, transmission losses would increase and some of the output of the new station would, in effect, be 'lost' to the system. However, if the new power station were to be located in the south and this displaced northern generation, the converse would be true; north to south power flows would decrease, system losses would decrease and the relative net effect would be as if a larger station had been installed.

Table 7.4 demonstrates this by showing the relative effect on transmission losses of locating 100MW of new generating plant in each zone consecutively. For this purpose, the 17 SYS Study Zones introduced in Chapter 6 under "SYS Boundaries and SYS Study Zones" have been used.

Please note, however, that the power flows presented in this Statement are based around a winter peak demand case using an average plant availability which tends to give rise to a general north to south power transfer. At other times of the year, when plant availability and market conditions may modify the generation patterns, zonal losses can change dramatically. For example, if Scotland becomes an importing area during the summer period then siting generation in Scotland is likely to have a beneficial effect on transmission losses.

The analysis was carried out against the SYS background for the 2010/11 winter peak. The installation of new generation was represented by a 100MW reduction in demand spread across the nodes within the relevant zone. The computer program used in the analysis requires that the total generation matches total demand (including losses) and scales generation capacity accordingly. The studies were arranged such that the effective 100MW of new generation was compensated for by a slight reduction in the output of all other generation in the study. That is no plant was displaced from operating. This was repeated for each of the 17 zones and the change in losses, relative to a reference case where no 100MW of new generation was introduced, was calculated.

Table 7.4 is based on the calculations conducted as described above and lists the effectiveness of placing 100MW of additional generation in each zone. The effectiveness has been expressed in percentage terms. For example, an effectiveness of 92% means that for generation increase of 100MW in the zone in question, 92MW would meet demand, while 8MW would be lost to increased losses. The effectiveness expressed in percentage terms provides an indication of the effectiveness of the installation of levels of generation greater than 100MW.

The change in losses is, of course, due to the overall increase or decrease in transfers across the national electricity transmission system rather than due to a local change in the zone in which the additional generation is located. The absolute values of effectiveness should not be relied upon, given the simplicity of the underlying studies. However, arranging the zones in order of effectiveness, as in Table 7.4, does provide a useful, and reasonably robust, indicator of the relative merits of locating generation in each of the 17 SYS Study Zones across the system on the basis of optimising (i.e. minimising) overall transmission system losses.

Table 7.4 shows that a small increase in generation in the zones north of zone 5 has an effectiveness of less than 90% in meeting demand across the system at the time of winter peak. In contrast to this, a small increase in generation in the South West (zone 17) has an effectiveness of 111% in meeting demand by virtue of reducing transmission power losses. Whilst these results are very broad brush and absolute percentages should not be relied upon, the relative order is considered reasonably robust. Please note that the generation effectiveness in zones 1 to 6 is likely to be understated due to the non-compliance of Boundary 6.

Finally, whilst the results may hold for the addition of 100MW of new generation, it does not follow that they would hold for say 1000MW of new generation. The aim of the above exercise was to provide an insight into the general effect of generation location on the overall NETS transmission losses. The capacity of 100MW of new generation was selected as, in itself, it has a relatively small system impact. The choice of a larger capacity (say 1000MW) would be more likely to incur heavy local loading of transmission circuits creating increased local transmission losses. Depending on the location, this may increase or decrease the overall NETS system losses. It is also more likely that a generator of this size would require network reinforcement to ensure compliance with the Licence Standard. Consequently, it would not be appropriate to calculate zonal losses until that reinforcement had been included in the study. The effect of a smaller generator capacity (say 1MW) would not be seen.

Table 7.1 - SYS Study Zones, Studied Zonal Generation, Demand and Transfer

Zone	Zone Name	Quantity (MW)	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Z1	North West (SHETL)	Effective Generation	870	899	887	1131	1453	1444	1388
Z1	North West (SHETL)	Demand	479	490	489	483	492	496	494
Z1	North West (SHETL)	Planned Transfer	391	409	398	648	961	948	894
Z2	North (SHETL)	Effective Generation	1250	1244	1273	1262	1453	1444	1428
Z2	North (SHETL)	Demand	572	564	566	560	571	559	554
Z2	North (SHETL)	Planned Transfer	678	680	707	702	882	885	874
Z3	Sloy	Effective Generation	306	305	301	327	323	321	182
Z3	Sloy	Demand	59	51	51	52	52	58	56
Z3	Sloy	Planned Transfer	247	254	250	275	271	263	126
Z4	South (SHETL)	Effective Generation	468	466	460	479	531	527	464
Z4	South (SHETL)	Demand	522	523	522	513	524	517	511
Z4	South (SHETL)	Planned Transfer	-54	-57	-62	-34	7	10	-47
Z5	North (SPT)	Effective Generation	2246	2343	2114	1988	2006	2010	1960
Z5	North (SPT)	Demand	1222	1221	1209	1235	1250	1262	1236
Z5	North (SPT)	Planned Transfer	1024	1122	905	753	756	748	724
Z6	South (SPT)	Effective Generation	3898	4211	4603	4583	4653	4419	3930
Z6	South (SPT)	Demand	2830	2835	2848	2864	3046	3036	3013
Z6	South (SPT)	Planned Transfer	1068	1376	1755	1719	1607	1383	917
Z7	North & NE England	Effective Generation	2919	2997	3099	3456	3785	3841	3919
Z7	North & NE England	Demand	2748	2710	2679	2697	2712	2615	2506
Z7	North & NE England	Planned Transfer	171	287	420	759	1072	1226	1413
Z8	Yorkshire	Effective Generation	11327	10770	10303	10016	9657	9273	8938
Z8	Yorkshire	Demand	5786	5655	5538	5652	5760	5767	5749
Z8	Yorkshire	Planned Transfer	5541	5115	4765	4364	3897	3506	3189
Z9	NW England & N Wales	Effective Generation	8000	7656	7376	7393	7356	7222	7126
Z9	NW England & N Wales	Demand	7219	7258	7314	7258	7195	7182	7136
Z9	NW England & N Wales	Planned Transfer	781	398	61	136	161	40	-10
Z10	Trent	Effective Generation	5637	5924	6258	5970	5640	5585	5559
Z10	Trent	Demand	704	717	731	717	702	693	680
Z10	Trent	Planned Transfer	4933	5207	5526	5253	4938	4892	4879
Z11	Midlands	Effective Generation	3397	3685	4002	3785	3541	3490	3457

Table 7.1 - SYS Study Zones, Studied Zonal Generation, Demand and Transfer

Zone	Zone Name	Quantity (MW)	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Z11	Midlands	Demand	6594	6738	6899	6884	6864	6878	6862
Z11	Midlands	Planned Transfer	-3197	-3053	-2897	-3099	-3323	-3389	-3405
Z12	Anglia & Bucks	Effective Generation	4054	4143	4266	4446	4594	4685	4804
Z12	Anglia & Bucks	Demand	5628	5551	5489	5484	5475	5479	5458
Z12	Anglia & Bucks	Planned Transfer	-1574	-1408	-1223	-1038	-882	-793	-654
Z13	S Wales & Central England	Effective Generation	6235	6169	6154	5920	5644	5546	5478
Z13	S Wales & Central England	Demand	4814	4795	4787	4785	4779	4789	4777
Z13	S Wales & Central England	Planned Transfer	1421	1375	1367	1135	865	757	701
Z14	London	Effective Generation	1723	1700	1691	1863	2021	1846	1679
Z14	London	Demand	9824	9902	10005	10089	10165	10252	10294
Z14	London	Planned Transfer	-8101	-8202	-8314	-8226	-8143	-8406	-8615
Z15	Thames Estuary	Effective Generation	2497	2457	2438	2316	2178	3217	4281
Z15	Thames Estuary	Demand	2004	2013	2028	2022	2016	2008	1992
Z15	Thames Estuary	Planned Transfer	493	444	410	294	163	1209	2289
Z16	Central S Coast	Effective Generation	1239	1056	882	876	863	855	851
Z16	Central S Coast	Demand	4211	4170	4140	4127	4110	4116	4103
Z16	Central S Coast	Planned Transfer	-2972	-3115	-3258	-3251	-3247	-3261	-3252
Z17	South West England	Effective Generation	1757	1734	1725	2140	2537	2511	2500
Z17	South West England	Demand	2605	2567	2535	2529	2522	2528	2524
Z17	South West England	Planned Transfer	-848	-833	-811	-390	15	-17	-24
All	Total	Effective Generation	57823	57760	57831	57951	58236	58236	57944
All	Total	Demand	57823	57760	57831	57951	58236	58236	57944
All	Total	Planned Transfer	0	0	0	0	0	0	0

Table 7.2 - Studied Boundary Generation, Demand and Transfer (MW)

Boundary	Boundary Name	Quantity (MW)	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
B1	SHETL North West	Effective Generation	870	899	887	1131	1453	1444	1388
B1	SHETL North West	Demand	479	490	489	483	492	496	494
B1	SHETL North West	Planned Transfer	391	409	398	648	961	948	894
B2	SHETL North - South	Effective Generation	2120	2143	2160	2393	2906	2888	2816
B2	SHETL North - South	Demand	1051	1054	1055	1043	1063	1055	1048
B2	SHETL North - South	Planned Transfer	1069	1089	1105	1350	1843	1833	1768
B3	Sloy	Effective Generation	306	305	301	327	323	321	182
B3	Sloy	Demand	59	51	51	52	52	58	56
B3	Sloy	Planned Transfer	247	254	250	275	271	263	126
B4	SHETL - SPT	Effective Generation	2894	2914	2921	3199	3760	3736	3462
B4	SHETL - SPT	Demand	1632	1628	1628	1608	1639	1630	1615
B4	SHETL - SPT	Planned Transfer	1262	1286	1293	1591	2121	2106	1847
B5	SPT North - South	Effective Generation	5140	5257	5035	5187	5766	5746	5422
B5	SPT North - South	Demand	2854	2849	2837	2843	2889	2892	2851
B5	SPT North - South	Planned Transfer	2286	2408	2198	2344	2877	2854	2571
B6	SPT - NGET	Effective Generation	9038	9468	9638	9770	10419	10165	9352
B6	SPT - NGET	Demand	5684	5684	5685	5707	5935	5928	5864
B6	SPT - NGET	Planned Transfer	3354	3784	3953	4063	4484	4237	3488
B7	Upper North	Effective Generation	11957	12465	12737	13226	14204	14006	13271
B7	Upper North	Demand	8432	8394	8364	8404	8647	8543	8370
B7	Upper North	Planned Transfer	3525	4071	4373	4822	5556	5463	4901
B8	North - Midlands	Effective Generation	31284	30891	30416	30635	31217	30501	29335
B8	North - Midlands	Demand	21438	21306	21216	21313	21603	21493	21255
B8	North - Midlands	Planned Transfer	9846	9584	9200	9322	9615	9008	8080
B9E	Midlands - South (Export)	Effective Generation	40318	40500	40676	40389	40399	39575	38352
B9E	Midlands - South (Export)	Demand	28736	28761	28846	28914	29169	29064	28797
B9E	Midlands - South (Export)	Planned Transfer	11582	11739	11829	11475	11230	10512	9555
B9I	Midlands - South (Import)	Effective Generation	17505	17323	17147	17434	17424	18248	19471
B9I	Midlands - South (Import)	Demand	29087	29062	28977	28909	28654	28759	29026
B9I	Midlands - South (Import)	Planned Transfer	-11582	-11739	-11829	-11475	-11230	-10512	-9555
B10	South Coast	Effective Generation	2996	2789	2607	3016	3400	3366	3351

Table 7.2 - Studied Boundary Generation, Demand and Transfer (MW)									
Boundary	**Boundary Name**	**Quantity (MW)**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
B10	South Coast	Demand	6816	6737	6676	6656	6632	6644	6627
B10	South Coast	Planned Transfer	-3820	-3948	-4069	-3641	-3232	-3278	-3276
B11	North East & Yorkshire	Effective Generation	23284	23235	23040	23242	23861	23279	22209
B11	North East & Yorkshire	Demand	14218	14049	13902	14055	14407	14311	14119
B11	North East & Yorkshire	Planned Transfer	9066	9186	9139	9186	9454	8969	8090
B12	South & South West	Effective Generation	9231	8959	8761	8936	9044	8912	8829
B12	South & South West	Demand	11631	11532	11463	11441	11411	11433	11404
B12	South & South West	Planned Transfer	-2400	-2573	-2702	-2506	-2367	-2521	-2576
B13	South West	Effective Generation	1757	1734	1725	2140	2537	2511	2500
B13	South West	Demand	2605	2567	2535	2529	2522	2528	2524
B13	South West	Planned Transfer	-848	-833	-811	-390	15	-17	-24
B14	London	Effective Generation	1723	1700	1691	1863	2021	1846	1679
B14	London	Demand	9824	9902	10005	10089	10165	10252	10294
B14	London	Planned Transfer	-8101	-8202	-8314	-8226	-8143	-8406	-8615
B15	Thames Estuary	Effective Generation	2497	2457	2438	2316	2178	3217	4281
B15	Thames Estuary	Demand	2004	2013	2028	2022	2016	2008	1992
B15	Thames Estuary	Planned Transfer	493	444	410	294	163	1209	2289
B16	North East, Trent & Yorkshire	Effective Generation	28921	29159	29298	29212	29501	28864	27769
B16	North East, Trent & Yorkshire	Demand	14923	14765	14633	14772	15109	15003	14799
B16	North East, Trent & Yorkshire	Planned Transfer	13998	14394	14665	14439	14392	13861	12970
B17	West Midlands	Effective Generation	3397	3685	4002	3785	3541	3490	3457
B17	West Midlands	Demand	6594	6738	6899	6884	6864	6878	6862
B17	West Midlands	Planned Transfer	-3197	-3053	-2897	-3099	-3323	-3389	-3405

Table 7.3 - System Power Losses at Peak							
Category	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Transmission Heating Losses excluding GSP Transformers (MW)	1053	1106	1123	1184	1235	1124	984
Fixed Losses (MW)	276	276	276	282	284	288	288
GSP Transformer Heating Losses (MW)	108	109	111	116	111	121	116
Total Transmission Losses	1437	1491	1511	1582	1631	1533	1387
ACS Peak Demand (MW) excluding Losses and Station Demand	56386	56269	56320	56369	56605	56703	56557
Total Transmission Losses as percentage of Demand	2.55%	2.65%	2.68%	2.81%	2.88%	2.70%	2.45%
Generator Transformer Heating Losses (MW)	119	120	114	146	125	135	128

Table 7.4 - Effectiveness of Marginal Generation due to Transmission Losses			
Zone Number	**Zone Name**	**Licensee**	**Effectiveness (%)**
Z1	North West (SHETL)	SHETL	<90
Z2	North (SHETL)	SHETL	<90
Z3	South (SHETL)	SHETL	<90
Z4	Sloy (SHETL)	SHETL	<90
Z5	North (SPT)	SPT	90
Z6	South (SPT)	SPT	92
Z7	North & NE England	NGET	97
Z8	Yorkshire	NGET	100
Z9	NW England & N Wales	NGET	100
Z10	Trent	NGET	100
Z11	Midlands	NGET	101
Z12	Anglia & Bucks	NGET	107
Z13	S Wales & Central England	NGET	108
Z14	London	NGET	109
Z15	Thames Estuary	NGET	112
Z16	Central S Coast	NGET	112
Z17	South West England	NGET	111

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Chapter 8

Transmission System Capability

Introduction

This chapter describes the capability of the national electricity transmission system to transport power at the time of the system ACS peak. The power system analyses underlying many of the results discussed in this chapter have been conducted on the basis of the deterministic SYS background. The deterministic SYS background comprises the customer based demand forecasts of Chapter 2 (Electricity Demand), the existing and future transmission contracted generation of Chapter 3 (Generation) and the existing and planned transmission network described in Chapter 6 (The Transmission System).

It should be noted that calculated system capabilities are a function of the generation, demand and transmission background against which they are assessed. Accordingly, the computed capabilities reported in this chapter are those which would arise should the SYS background be realised at the time of system peak. At other times and/or against other backgrounds different transmission capabilities may arise.

As explained in previous chapters, there is uncertainty associated with the demand forecasts and with future generation developments. Thus, it should be recognised that the SYS background does not necessarily represent the most likely outcome, nor should it be regarded as a 'forecast' of the outcome. Uncertainties in demand and generation developments 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, the transfers and capabilities arising from the deterministic SYS background have been presented against the backdrop of a range of probabilistic transfers. These probabilistic transfers reflect, in part, our current views on a range of criteria, which influence the likely future outcome given 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 the system and enable the reader to make more informed judgements on the opportunities for making new or further use of the transmission system.

The chapter also identifies those reinforcements which could be required, in addition to the planned reinforcements presented in Chapter 6 (The Transmission System), to achieve compliance with the Licence Standard on the basis of the SYS background. These additional reinforcements are subject to variation and should be regarded as indicative only.

In addition, a new section has been incorporated that refers to the work undertaken by the ENSG (Electricity Networks Strategy Group) in analysing what reinforcements would be required to meet the UK environmental targets, but in particular the electricity share of the renewable 2020 target.

The probabilistic range of transfers, which are presented in this chapter, have been derived using a National Grid program called the Generation Uncertainty Model (GUM). To provide a greater understanding of the probabilistic results presented and how they should be interpreted, the chapter includes a high level description of GUM.

System Boundaries

An understanding of the capability of the national electricity transmission system to transport power leads to an understanding of the ability of the national electricity transmission system to accommodate further generation and demand in different zones across the system. When considering the capability of the system, it is useful to consider the limits on the bulk transfer of power across certain system boundaries.

Accordingly, this chapter reports on a number of key boundary capabilities and, for this purpose, the 17 SYS boundaries described in "SYS Boundaries and SYS Study Zones" in Chapter 6 and shown graphically in Figure A.1.6. These boundaries are also shown in Figure A.2.3 for SHETL, Figure A.3.3 for SPT and Figure A.4.3 for NGET. These 17 boundaries have historically reflected some of the main weaknesses on the interconnected system. Such weaknesses can lead to the need to restrict power flows across the system; possibly through the potentially uneconomic constrained operation of generating plant. Alternatively, weaknesses in transmission may be removed by transmission reinforcement. Although the most critical boundaries may not be precisely the same as those studied, the 17 boundaries which have been used remain relevant for illustrating system trends and limitations.

Consideration of the range of possible future transfers across each of the 17 boundaries enables us to describe the type of reinforcement schemes, which may be required in order to ensure continued compliance with the Licence Standard.

Boundary Capabilities and Required Capabilities

Two types of system limitation, relating to the transfer of power across a boundary, have been considered. The first relates to thermal capability and the second to voltage capability. The boundary capabilities have been evaluated for the time of the system winter peak demand of 2010/11, 2012/13, 2014/15 and 2016/17 and are on the basis of the SYS background. These capabilities will, of course, potentially change at off-peak times but, as explained in "Off-Peak Power Flows" in Chapter 7, in the ‘real time’ operational time-phase, the system is managed such that it complies at all times with operational criteria of the Licence Standard.

As mentioned above, the Licence Standard defines certain unacceptable conditions, which shall not occur as a result of specific secured events. The unacceptable conditions referred to include:

- loss of supply capacity (except as permitted by specific demand connection criteria);
- unacceptable overloading of any primary transmission equipment;
- unacceptable voltage conditions or insufficient voltage performance margins; and
- system instability.

For example, in the case of planning the development of the Main Interconnected Transmission System, a boundary in which a single circuit is out of service due to a fault, must be capable of transferring the Planned Transfer (as defined in the Licence Standard) plus an allowance (also specified in the Licence Standard) to take account of non-average conditions (e.g. relating to power station availability, weather and demand) without any of the above unacceptable conditions arising. The allowance, referred to, is calculated by an empirical method described in the Licence Standard and is called the "Interconnection Allowance".

Similarly, the Licence Standard also requires that a boundary, in which two circuits are out of service (i.e. N-2 or N-D as appropriate), must be able to transfer the Planned Transfer plus half the calculated Interconnection Allowance without any unacceptable conditions arising.

Accordingly, the boundary thermal capability is the power flow that can be transferred across the boundary without causing any unacceptable conditions following the outage of two circuits (i.e. N-2 or N-D) as defined in the Licence Standard. The overall boundary capability is the lower of the thermal (MW) and voltage capabilities. Known stability limitations are also reported in the Boundary Commentary section which is presented later in this chapter. The required capability is simply the Planned Transfer plus half the Interconnection Allowance.

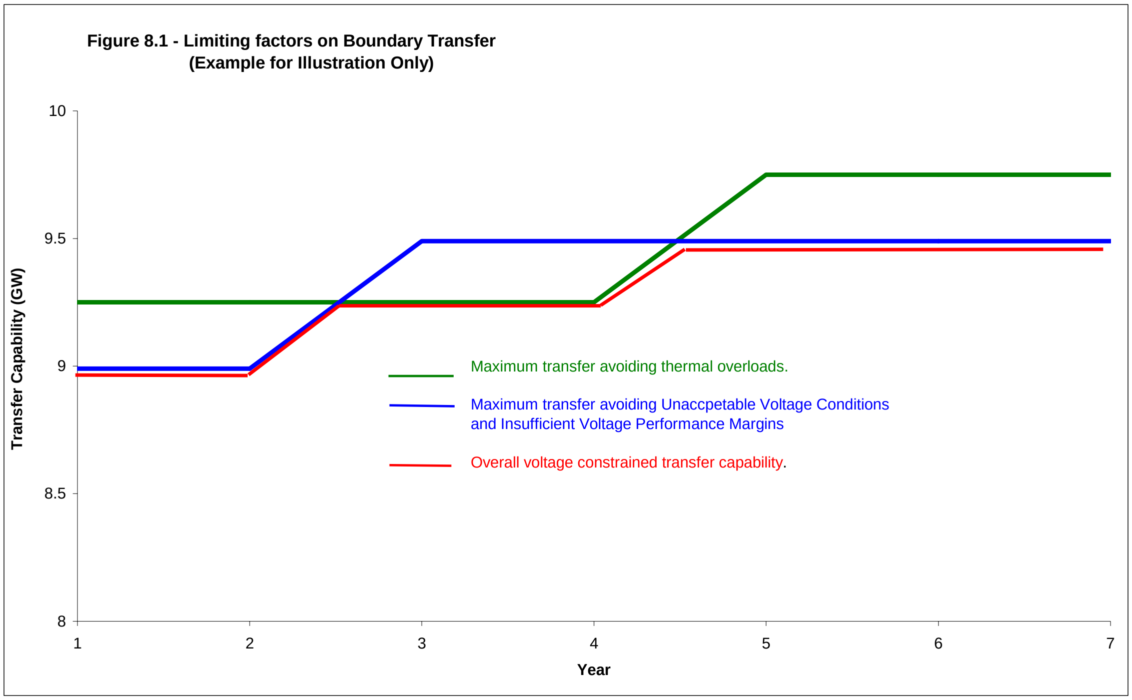
Please note, however, that application of the Interconnection Allowance (or part thereof) relates only to those boundaries, which divide the system into two contiguous parts, the smaller of which contains more than 1500MW of demand. In the case of the boundaries, which have been defined for the NGET and SPT systems, this is always the case. However, for a number of boundaries in the SHETL system (namely: boundaries B1, B2 and B3), this is not the case and, in these instances, the required capability quoted is simply the Planned Transfer.

The boundary capabilities reported in this chapter give an indication of the maximum boundary transfer that can be supported without contravening any of the above unacceptable conditions following a secured event. A boundary capability that is less than the required capability indicates a need for transmission reinforcement. A boundary capability that is greater than the required capability shows only that the security criteria are satisfied for the particular transfer conditions and background studied.

While not identical (particularly for voltage control and fault levels), in terms of flows on the system, the withdrawal of generation will have a broadly similar effect to the addition of demand and vice versa. The amount by which a boundary capability exceeds the required capability gives an indication of the approximate extent of 'spare' transfer capability on that boundary. However, this does not necessarily mean that an equivalent volume of additional generation on the exporting side of the boundary (or an equivalent volume of additional demand on the importing side) can be readily accommodated. This can be due to a number of reasons including:

- there may be a need for 'local' reinforcements not directly related to the boundary;
- as additional generation or demand is connected to the system, the background against which both the required capability and boundary capability are assessed changes; and
- the security criteria must be satisfied for all system boundaries indicated by the Licence Standard, i.e. while a particular connection may satisfy conditions for one boundary, it may fail to do so for another.

The nature of a boundary capability can be illustrated by separately establishing the voltage capability and the thermal capability. The way in which voltage or thermal considerations might be the limiting factor in different years is illustrated in Figure 8.1. The voltage capability is shown as a blue line (this may arise either because of unacceptable voltage conditions or insufficient voltage performance margin, whichever limit arises first), and the thermal capability as a green line. The net boundary capability is shown by the red line.

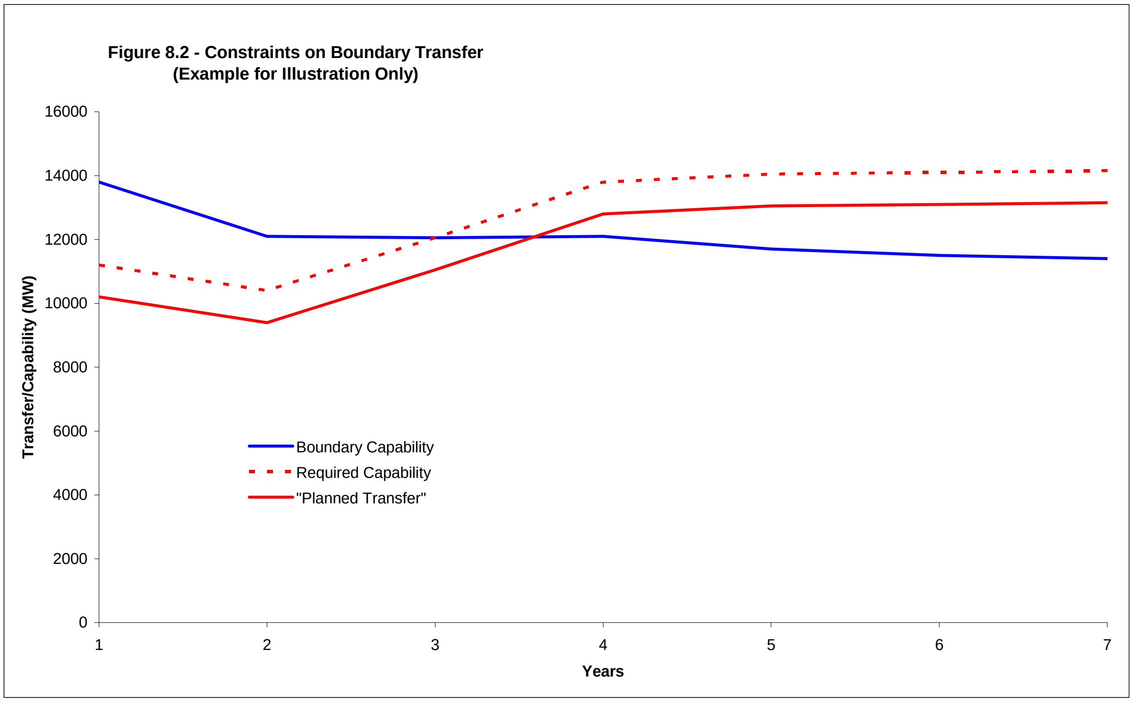


Deterministic Transfers

The power flows presented in this chapter are based on the deterministic SYS background. There is inherent uncertainty associated with the assumptions underlying any deterministic background. For example demand and generation may, in the event, deviate from any of the deterministic assumptions underlying the background. Uncertainty must also therefore be attributed to both the resultant deterministic power flows and any consequent perceived need for transmission reinforcement. The SYS background is no exception and, while it has been selected as the most reasonable deterministic background for the purposes of Chapter 7, it should not be assumed that it represents the most likely future outcome.

For ease of explanation, the boundary commentaries presented later in this chapter include a series of figures (Figure 8.B1, Figure 8.B2, Figure 8.B3, Figure 8.B4, Figure 8.B5, Figure 8.B6, Figure 8.B7, Figure 8.B8, Figure 8.B9, Figure 8.B10, Figure 8.B11, Figure 8.B12, Figure 8.B13, Figure 8.B14, Figure 8.B15, Figure 8.B16 and Figure 8.B17). Amongst other things, each of these figures shows the planned transfer, the required capability and the actual calculated capability for the relevant boundary. These values are all calculated on the basis of the deterministic SYS background and, in view of this, they are often referred to as the "SYS Transfer", the "SYS Required Transfer" and the "SYS Capability" respectively.

As specified by the Licence Standard, for a particular generation and demand background, the required capability is simply the planned transfer enhanced by the appropriate Interconnection Allowance for the boundary in question. Where the required capability is less than the actual boundary capability, there is no need for further reinforcement in respect of that particular boundary. An example of this is given in Figure 8.2, which illustrates that the required capability exceeds the actual capability from around year 3 onwards indicating a potential need for further reinforcement on the basis of the SYS background.



The boundary capabilities quoted in this chapter relate to planning the medium to long term future development of the system and are not necessarily appropriate to the real time operation of the system. Operational boundary capabilities are a function of the real time transfer, which can be achieved within operational timescales for a given pattern of system outages, demand and generation availability. In operational timescales each of these factors is known with a relatively high degree of certainty, which is unlike in the planning time phase where there is a need to consider a great many more uncertainties.

The boundary capabilities reported in this chapter do, nevertheless, provide a good broad appreciation of the overall capability of the national electricity transmission system to transport power. An apparent surplus of boundary capability over the required capability generally shows the exporting side to have at least some potential for additional generation and the importing side to have some potential for additional demand. A deficit of boundary capability against the required capability provides an indication that, were the SYS background to be realised, either investment to reinforce the system and thereby enhance the capability may be appropriate, or alternatively constrained operation of generation is required in order to limit the boundary transfers to within acceptable levels.

The possible need, or otherwise, for transmission reinforcement is discussed under "Boundary Commentary" later in this chapter.

Finally, for the purpose of providing the power flow information reported in this chapter and in Chapter 7, it is first necessary to be able to obtain a converged AC power flow study at least for the intact system and for the Planned Transfer Condition. Under the SYS background there are a number of boundaries for which the boundary capability is substantially lower than the planned transfer in a number of years. In those cases where such deficits are large, convergence of the AC power flow program may be inhibited. In such cases it may be necessary to add a minimum number of indicative system reinforcements solely for the purpose of obtaining convergence of the Planned Transfer Condition. These ‘indicative convergence works’ (e.g. reactive compensation to achieve acceptable voltage conditions) are not necessarily sufficient for compliance with the Licence Standard, and the boundary capabilities have been quoted with them included.

Probabilistic Transfers

The Generation Uncertainty Model (GUM)

Deterministically derived boundary transfers are useful but have limited value since they do not consider the uncertainties associated with projected future demand and generation developments. It is important to take account of the potential impact of these uncertainties on power transfers across key transmission boundaries when considering the merits of transmission reinforcements.

For a given set of assumptions relating to demand and generation, the Generation Uncertainty Model (GUM) provides a probabilistic representation of the electricity market. GUM employs a Monte Carlo model in which openings of new generating stations and closures of existing stations are randomly selected (subject to the influence of the input assumptions) against a background of uncertain demand growth. The resultant probabilistic transfers reflect our current view of how the planned transfers across each of the 17 boundaries at the time of system peak are likely to develop over the next seven years.

Factors which have been taken into account in compiling the input data for GUM include but are not limited to the possible:

- variations in demand growth;
- variations in Plant Margin;
- generation closure and placing in reserve (station CEC=TEC=0 or TEC < station CEC). Within GUM these are referred to as "closures";
- return to service of plant currently held in reserve. Within GUM these are referred to as "re-openings";
- new power stations, which have received approval, proceeding to completion. Within GUM these are referred to as "openings";
- additional proposed new power stations receiving approval and proceeding to completion. Within GUM these are again referred to as "openings";
- termination or modification to current generation connection agreements; and
- variations (including exports) in transfers over the External Interconnections with External Utilities.

It is not possible to provide the detail of the input assumptions we have made since this would breach our obligations on commercial confidentiality. The probabilistic transfer information is provided without prejudice and reflects our current view of future uncertainty. Clearly, this view may change as developments in the electricity market in Great Britain unfold, but nevertheless it should prove a useful complement to the simple deterministic SYS background approach.

The purpose of presenting this additional information is to:

- provide a more meaningful view of the possible range of future boundary transfers given an unconstrained transmission system;
- place the deterministic SYS background based boundary transfers and capabilities in the context of what we currently believe to be the likely range of future transfers;

- promote an appreciation of the future uncertainty in relation to planning the development of the transmission system; and

- enable the reader to make more informed judgements on the opportunities for making new or further use of the transmission system without incurring the need for major inter-zonal transmission reinforcement.

Overview of GUM Analyses

For each year within the period of study, GUM models the system at the time of peak demand on the national electricity transmission system. This is consistent with the deterministic boundary transfer and capability analyses. The program does not simulate the system year-round; its purpose is to model the generating capacity that might be available to meet the likely peak demand.

The input information provided to GUM reflects our current views on the various generation and demand uncertainties. Our market intelligence in this area is largely based on material in the public domain. In compiling the input assumptions we have tried to avoid introducing any bias. Clearly, our views may change as developments in the electricity market in Great Britain unfold. Nevertheless, the results obtained from GUM analyses should prove more stable than a simple deterministic approach.

There are currently more generation projects proposed than are essential to meet forecast demand. From experience, we consider it unlikely that all of these projects will be completed as planned. Some may slip from their planned commissioning dates while others will be terminated. At the same time, some existing plant can be expected to close down due to age alone while some may close due to competitive pressure from more efficient new market entrants or due to increasing pressure due to environmental constraints. We are not attempting to predict specific generation openings and closures, yet we need to know their probable effects on the power flows on the transmission system. GUM can be used to provide us with this information.

To estimate the probable ranges of power transfer, GUM randomly selects generator openings and closures, balancing the probable generation capacity against probable peak demand and probable Plant Margin. The random selections are weighted according to a range of input information and criteria, which influence the likelihood of the station opening or closing. Weightings for station openings consider, but are not limited to, the stage of development activity for the stations (which includes issues such as consents status), environmental impact, thermal efficiency, fuel type, and availability of fuel, water, and transmission. Weightings for station closure include, but are not limited to, age, thermal efficiency, fuel delivery, fuel type, availability and environmental impact.

By making random selections of demand and generation according to the given probability functions and weightings, GUM generates up to 10,000 demand/generation permutations or backgrounds. Each single background represents a time sequence of demand growth, plant openings and plant closures running from 2009/10 to 2016/17.

However, a typical GUM analysis does not model every possible future; rather it represents a possible range of variations around the overall demand growth forecast and range of possibilities within the current list of generation projects. Changing the underlying assumptions (for example, a major change in relative fuel costs, or changes in the location and timing of new generation projects) would have some effect on the power transfer ranges.

GUM Boundaries and Zones

For each of the 10,000 backgrounds, GUM calculates the net generation capacity surplus or deficit for each specified GUM zone or group of GUM zones. This surplus or deficit then permits the calculation of the range of possible transfers out of or into each specified zone or group of zones for each sampled generation background. By calculating the net transfer for each of the 10,000 backgrounds within each year of the study period, it is possible to show probabilistic ranges of net transfers into or out of each specified zone, or group of zones, year by year. The program only considers net transfers. Since GUM does not incorporate a network model, it does not in itself calculate power flows across individual circuits.

As with the deterministic analyses, it is useful to consider probabilistic power transfers across certain critical boundaries. The GUM analyses presented in this chapter are based around the SYS Boundaries and SYS Study Zones introduced in Chapter 6 under "SYS Boundaries and SYS Study Zones"). Since GUM calculates net imports and exports for zones and groups of zones, all GUM boundaries are defined in terms of the complete boundary surrounding specified single zones or groups of zones.

Accordingly, each boundary under study is defined in terms of the zones on one side of that boundary. Table 8.1 lists the defining zones on one side of each of the main SYS boundaries. For boundaries B10 & B12 the defining zones are south of the boundary. For boundaries B1, B3, B13, B14, B15 & B17 the defining zones are those encompassed by the boundary. For all other boundaries, the defining zones are north of the boundary.

Presentation of Results

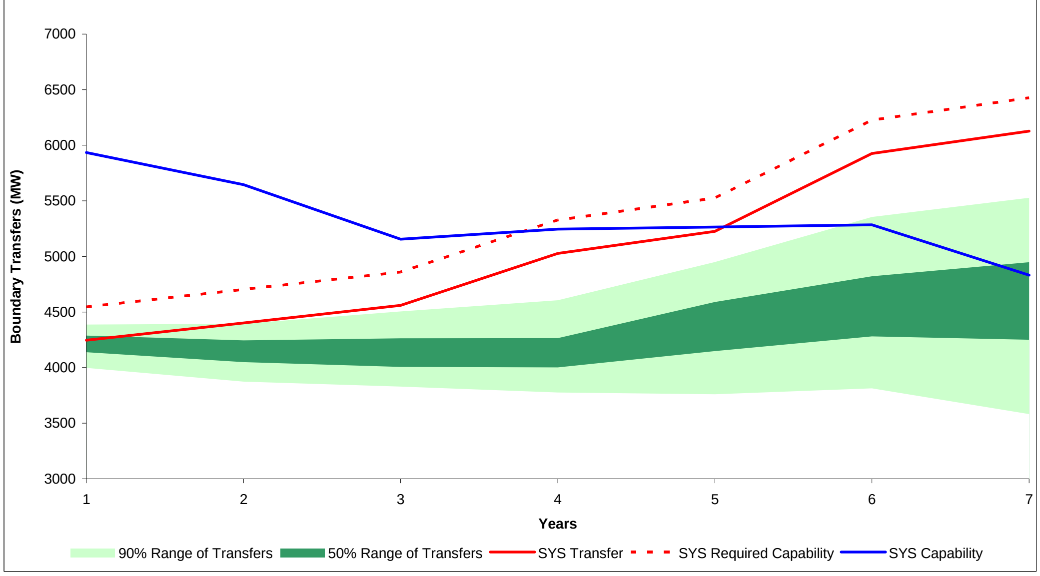
The Fan Diagram

A key output of GUM is the probabilistic range of transfers over a given period for each defined boundary. For each year of the study, GUM calculates probabilistic distributions of power transfers for each boundary under peak load conditions. These distributions could be plotted as separate charts for each boundary for each year. However, a concise and convenient method of presenting the results is to plot percentiles of the distributions to show how the range of probable transfers varies year by year for each boundary.

The resultant plots typically display a narrower range of transfers in the earlier years than in the later years, since there is greater certainty associated with the earlier years. The characteristic shape is therefore generally in the form of a fan and, in view of this, the diagrams are often referred to as "fan diagrams".

An illustrative example is given in Figure 8.3. The green shaded area shows the range of probabilistically derived transfers arising out of the GUM analyses. The deterministic SYS planned transfer, the deterministic SYS required capability and the deterministic SYS capability have been superimposed on top of the "fan" of probabilistic transfers for comparison.

Figure 8.3 Boundary Transfers and Capability (Illustrative Example)



In the illustrative example of Figure 8.3, 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 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.

GUM takes as its starting point the existing pattern of zonal demand and generation at the time of the 2009/10 winter peak. Conditions in the following year should be fairly predictable, nevertheless there are uncertainties that are represented in GUM's probabilistic analysis. For example, a power station may be scheduled to commission by the 2010/11 winter peak, but construction may slip such that it is unable to contribute to the system peak demand until 2011/12. Variations and uncertainties relating to transfers across the External Interconnections with External Systems are included in the probabilistic analyses. This can account for a significant part of the range of uncertainty displayed in the fan diagrams.

Interpretation

In the arbitrary example given in Figure 8.3 the deterministic SYS required capability exceeds the SYS boundary capability by year four, which implies that there are no opportunities for additional generation on the exporting side of the boundary from that year without reinforcement. The probabilistic transfers, indicated by the fan, imply that the need for reinforcement is unlikely until the later years, if at all. Any reinforcement can therefore be delayed until the later years when the need becomes more certain.

However, as noted previously, these kinds of conclusions must be qualified by recognition that the boundary capability is dependent on the exact disposition of generation and demand in the background against which it is assessed. For example, interactions of generation openings and closures and changes in demand all on the same side of a boundary, or on opposite sides, can lead to little or no change in the ‘Planned’ boundary transfer but, nevertheless could give rise to a need for significant reinforcements in order to maintain system security. Nor would two backgrounds, which, result in similar transfers across a particular boundary necessarily, give rise to the need for the same transmission reinforcement across that boundary since the boundary capability is a function of how the boundary transfer is shared between the boundary circuits, which is in turn a function of the particular background under consideration.

An important message is that the requirement for transmission system reinforcement does not simply correspond to a given boundary transfer. The need for system reinforcement can still arise at transfers below the ‘SYS capability’ levels displayed in the series of figures (i.e. Figure 8.B1 to Figure 8.B17) included in the next section of this chapter.

Boundary Commentary

Background

For a better understanding of the results presented in this section the reader is advised to first read the previous sections of this chapter. In particular the format of the figures used is as presented in Figure 8.3. The SYS background transfers presented are consistent with the power flow studies discussed in Chapter 7 (Transmission System Performance) which were also based on the generation ranking order of operation given in Table 7.1.

Please note that the transfers displayed in the series of figures which follow (i.e. Figure 8.B1 to Figure 8.B17) relate to the time of system peak demand. The capabilities shown are the transfer levels beyond which either thermal or voltage limitations become apparent on the Main Interconnected Transmission System. These SYS capabilities have been evaluated for the spot years 2010/11, 2012/13, 2014/15 and 2016/17 only. It is stressed that the SYS capabilities are appropriate for the SYS background and do not necessarily correspond to any of the many backgrounds appropriate to the probabilistic transfer range. The SYS capability does nevertheless provide a useful reference and initial indicator of overall capability.

The probabilistic transfer ranges shown are considered to be a more realistic representation of the likely transfer range than the single deterministic SYS background transfers and naturally receive attention in the commentary that follows. However, apart from a high level comparison, it is not possible to provide a detailed commentary on the probabilistic ranges since to do so could breach our obligations to our customers on commercial confidentiality. For the single deterministic SYS background transfers this is not a concern and accordingly greater detail has been included in the commentary.

In considering each of the following boundary commentaries it is useful to cross reference a number of tables presented elsewhere which are relevant to the SYS background transfers. Table 7.3 presents the SYS background studied generation, demand and transfer for each boundary. For ease of reference, each of the following boundary commentaries includes the relevant extract of Table 7.3. Please refer to Table 3.8 for details of generation capacity changes under the SYS background over the period from 2010/11 to 2016/17 inclusive, Table 3.10 for generation disconnections from 2010/11 to 2016/17 inclusive, and to Table 3.11 for generating units declared unavailable.

Overview

As explained in Chapter 3, access to the national electricity transmission system is provided through arrangements with National Grid, acting as NETSO, under the Connection and Use of System Code (CUSC). The CUSC sets out the contractual framework for connection to, and use of, the national electricity transmission system. The CUSC has applied across the whole of Great Britain since BETTA "go-live" (1 April 2005).

The removal, under BETTA, of the previous commercial arrangements for the use of the circuits connecting Scotland and England has given wider rights of GB system access than previously was the case. However, the volume of requirements for connection to and use the national electricity transmission system has meant that:

- there is a potential shortage of transmission system capacity, and
- transmission reinforcement is required to maintain compliance with the Licence Standard.

The results, reported in this chapter, demonstrate this potential transmission capacity shortage under the SYS background. As a consequence, there is a potential need for significant reinforcement of the system in addition to those identified in Table 6.2.

After the introduction of BETTA , which brought about the removal of the administered Interconnection arrangements between England and Scotland, an extensive reinforcement programme is required to accommodate the required capabilities determined by the SYS background for boundaries in the border area. These reinforcements include planned Beauly/Denny transmission reinforcement and strategic reinforcements as planned through ENSG. The Beauly/Denny reinforcements is included as part of the SYS background for commissioning by 2013/14. In addition the first stages of the strategic ENSG reinforcements are also included.

Examination of the boundary transfer levels over the seven year period for the 'SYS background' indicates that:

- The major Northern 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) all show steady growth in power transfers over the SYS period due primarily to contracted renewable energy developments throughout Scotland. A sudden drop in power flow South happens in 2016 when some LCPD closures are expected. Further increase in new renewable generation in the North will push the boundary transfers higher.

- Boundaries B8 (North to Midlands) and B9 (Midlands to South), B11 (Northeast & Yorkshire), (B12) South & Southwest import, B16 (Northeast, Trent & Yorkshire) and West Midlands import (B17) show mostly constant power flows with some fluctuation due to new generation connections and older generation closures.

- Central London import (B14) show a trend of a steady increase in transfers reflecting gradually increasing demands and the lack of new generation projects within this zone;

- There is a general trend with reducing transfers across the South Coast import (B10), 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.

Comparison of the SYS Planned Transfers with the probabilistic ranges reveals that for most all boundaries the SYS transfers lay very close the probabilistic range with only limited deviation which can be explained by the effect of some large individual generators pushing the transfer points.

Examination of Figures 8.B1 to Figure 8.B17 reveals a wide range in the width of the probabilistic transfer envelope across the various boundaries. For boundaries cutting large importing or exporting areas such as Boundary 8 (North to Midlands) and Boundary 9 (Midlands to South), the width of the probabilistic transfer envelope reflects, inter alia, the higher uncertainty associated with the larger tranche of generating plant on the exporting side. For other boundaries, such as Boundary 14 (London) which is an importing boundary dominated by a large demand with little generation, the width of the probabilistic transfer envelope is relatively narrow reflecting a higher degree of certainty.

The planned contracted and strategic reinforcements listed in Table 6.2 provide the transmission capability to cover the majority of the system boundary requirements. Some non-compliance for the major northern boundaries may be experienced for the early years until the necessary reinforcements are constructed or the power flow decreases enough to lie within capability.

Commentary

Boundary 1: SHETL North West

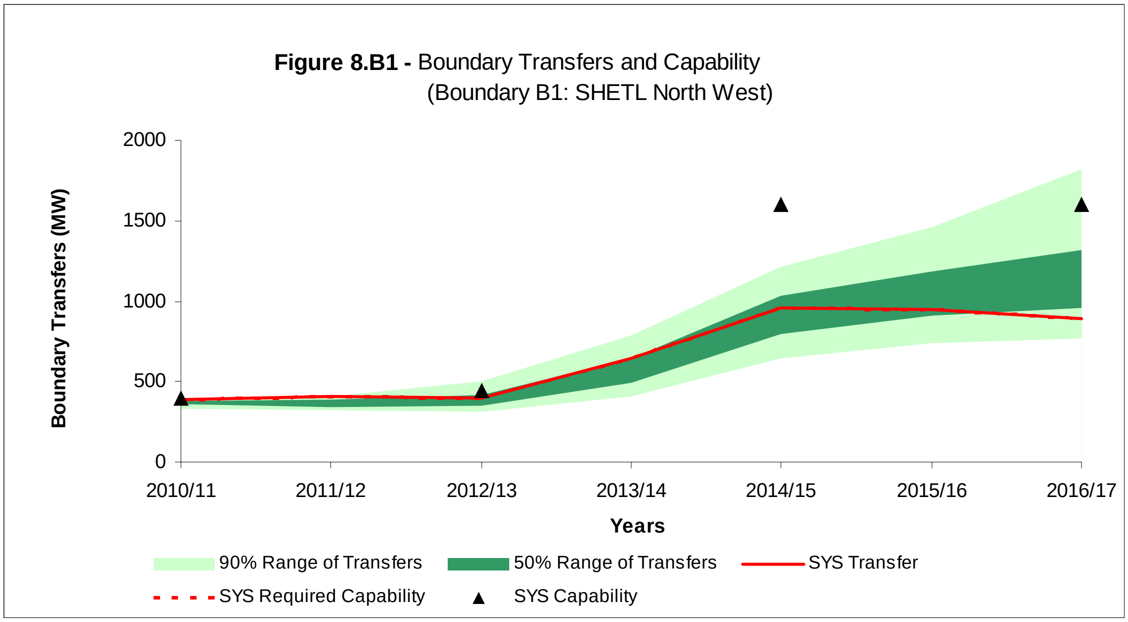


Table 8-T1 - Boundary B1 SHETL North West							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
B1E - EXPORT							
Effective Generation	870	899	887	1131	1453	1444	1388
Demand	479	490	489	483	492	496	494
Planned Transfer	391	409	398	648	961	948	894
B1I - IMPORT							
Effective Generation	56953	56924	56936	56692	56370	56379	56435
Demand	57344	57333	57334	57340	57331	57327	57329
Planned Transfer	-391	-409	-398	-648	-961	-948	-894

Generation to the north of this boundary is increasing at a significant rate due to the high volume of new wind based generation seeking connection in the area. Consequently, the boundary transfers are also increasing at a similar rate.

Please note that application of the Interconnection Allowance (or part thereof) relates only to those boundaries, which divide the system into two contiguous parts, the smaller of which contains more than 1500MW of demand. For this boundary (as with boundaries B2 and B3), this is not the case and accordingly the required transfer capability is equal to the Planned Transfer.

The first of the proposed reinforcements for this boundary is scheduled for completion by spring 2011 and comprises the creation of a new 275/132kV substation at Knocknagael. This is located to the south of Inverness at the existing Foyers connection tee point on the Beauly-Blackhillock line. It is proposed to move the existing Inverness demand onto this new substation using new 132kV cable circuits, thus reducing the load on the Beauly-Keith 132kV circuits and thereby increasing the B1 capacity to around 450MW.

The second proposed reinforcement is the Beauly-Denny project comprising the replacement of the existing 132kV double circuit tower line between Beauly, Fort Augustus, Errochty and Bonnybridge, by a new 400kV double circuit tower line terminating at Denny near Bonnybridge. The Beauly-Denny project was the subject of an extensive Public Inquiry which started in January 2007 and concluded successfully in January 2010 with consent from the Scottish

Government to build the line. Currently, the project completion date is predicted to be 2013. The completion of Beauly-Denny will increase this boundary capability from 450MW to around 1300MW.

The additional generation connecting to the north of this boundary means that further reinforcement of this boundary will be required. The next proposed reinforcement is strengthening of the transmission infrastructure between Beauly (near Inverness), Keith/Blackhillock and Kintore. The boundary capability can be raised to around 1600MW by replacing the conductor on the existing 275kV transmission line between Beauly, Blackhillock and Kintore with a new technology conductor of higher capacity. SHETL obtained regulatory approval to proceed to the construction phase of this reinforcement in March 2010.

If the generation volumes warrant it then the transmission capacity can be increased further by completion of a 400kV ring from Denny to Kincardine (via Errochty, Fort Augustus, Beauly, Keith, Kintore and Tealing). The 400kV ring can be achieved by making use of the proposed new Beauly-Denny, a new build transmission line between Beauly and Keith/Blackhillock and using existing infrastructure from Keith down the east coast to Kincardine which is already 400kV construction.

Within the North West boundary, additional transmission reinforcements will be required to connect the proposed new generation. For example, to the north of Beauly, additional works between Beauly and Dounreay (near Thurso) will be required. This will comprise installing a new conductor the spare side of the existing 275kV double circuit line between Beauly and Dounreay, installation of a 275kV busbar and a second 275/132kV transformer at Dounreay. Phase shifting transformers will also be required on the 132kV lines between Beauly and Shin. SHETL obtained regulatory approval to proceed to the construction phase of this reinforcement in March 2010.

Further reinforcement north of Beauly may be required depending on the location and volume of generation connections.

The significant interest from generation developers on the large Island groups of the Western Isles, Orkney and Shetland means that infrastructure will be required to connect these to the mainland transmission network. Current proposals are for the Western Isles to be connected using an HVDC transmission link to Beauly 400kV substation (already proposed as part of the Beauly-Denny infrastructure). It is also proposed to use an HVDC transmission link to connect Shetland to the mainland at a new 400kV busbar at Blackhillock Substation. The growth of renewable generation on mainland Orkney is more gradual, however the development of significant offshore wind and marine generation around Orkney and the Pentland Firth seems likely following the announcement by the Crown Estate to grant exclusive development rights to companies in these areas. Consequently, the extent to which reinforcement is required is under consideration.

The routes for new transmission infrastructures will undergo detailed environmental impact assessment and will be subject to consents and planning approval.

Boundary 2: SHETL North - South

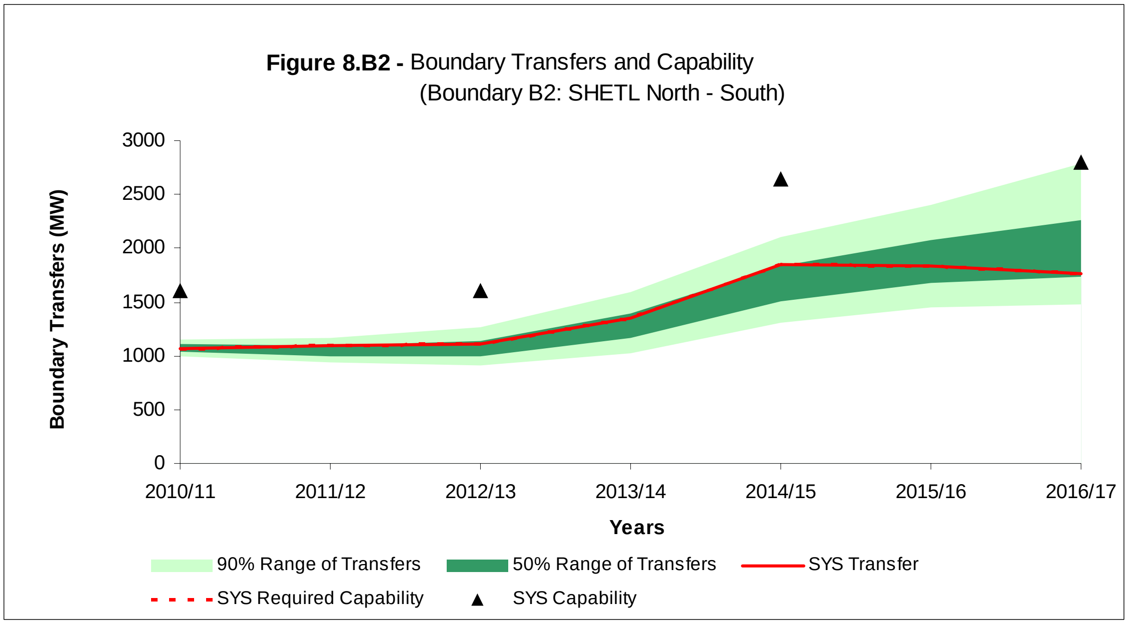


Table 8-T2 - Boundary B2 SHETL North- South							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
B2E - EXPORT							
Effective Generation	2120	2143	2160	2393	2906	2888	2816
Demand	1051	1054	1055	1043	1063	1055	1048
Planned Transfer	1069	1089	1105	1350	1843	1833	1768
B2I - IMPORT							
Effective Generation	55703	55680	55663	55430	54917	54935	55007
Demand	56772	56769	56768	56780	56760	56768	56775
Planned Transfer	-1069	-1089	-1105	-1350	-1843	-1833	-1768

Generation to the north of this boundary is increasing at a significant rate due to the high volume of new renewable generation seeking connection to the north of this boundary. Consequently, the boundary transfers are also increasing at a similar rate.

Please note that application of the Interconnection Allowance (or part thereof) relates only to those boundaries, which divide the system into two contiguous parts, the smaller of which contains more than 1500MW of demand. For this boundary (as with boundaries B1 and B3), this is not the case and accordingly the required transfer capability is equal to the Planned Transfer.

The increase in required transfer capability of this boundary over the seven year period indicates the need to reinforce the transmission system in this location. The proposed Beauly to Denny reinforcement required for the North West boundary also provides the necessary increased capacity for this boundary. The reinforcement comprises the replacement of the existing 132kV double circuit tower line between Beauly, Fort Augustus, Errochty and Bonnybridge, by a new 400kV double circuit tower line terminating at Denny near Bonnybridge. The Beauly-Denny reinforcement is due to be completed in 2013 and will increase the North South boundary capability from 1600MW in 2012/13 to 2650MW in 2013/14. Depending on the volume of future renewable generation applications, additional reinforcement of this boundary may be required. This could include a 400kV east coast upgrade from Blackhillock to Kincardine using existing infrastructure that is currently operated at 275kV but which is 400kV construction. Currently SHETL are undertaking pre-construction design and engineering of the 400kV east coast project with a view to completion in 2015 subject to an appropriate need case and regulatory approval.

Boundary 3: SHETL Sloy

Figure 8.B3 - Boundary Transfers and Capability (Boundary B3: Sloy)

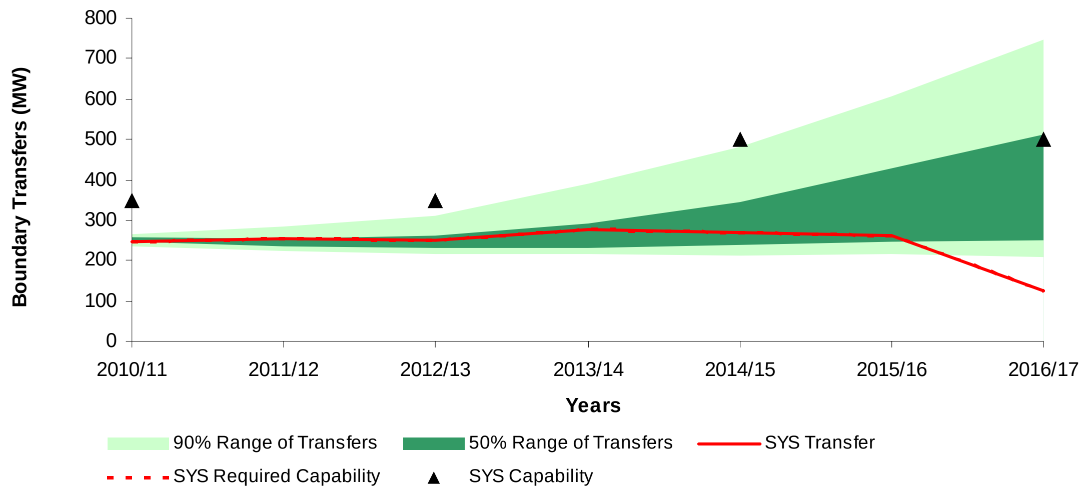


Table 8-T3 - Boundary B3 SHETL Sloy							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
B3E - EXPORT							
Effective Generation	306	305	301	327	323	321	182
Demand	59	51	51	52	52	58	56
Planned Transfer	247	254	250	275	271	263	126
B3I - IMPORT							
Effective Generation	57517	57518	57522	57496	57500	57502	57641
Demand	57764	57772	57772	57771	57771	57765	57767
Planned Transfer	-247	-254	-250	-275	-271	-263	-126

The application of the Interconnection Allowance (or part thereof) relates only to those boundaries, which divide the system into two contiguous parts, the smaller of which contains more than 1500MW of demand. For this boundary (as with boundaries B1 and B2), this is not the case and accordingly the required transfer capability is equal to the Planned Transfer.

A new 275/132kV substation will be completed in summer 2010 to link the existing Killin to Sloy 132kV line with the existing 275kV line which runs from Windyhill to Dalmally. The substation, called Inverarnan and located at a point near to where the lines cross at the north end of Loch Lomond, will increase the South West boundary capacity to around 350MW.

New renewable generation continues to increase in the Kintyre and Argyll area and further reinforcement will be required to address both the Zonal boundary capacity and the internal network capacity, particularly between Carradale and Inveraray. The proposed reinforcement for this area is the installation of two subsea cable links from Crossaig, north of Carradale, to Hunterston in Ayrshire. Currently SHETL are undertaking pre-construction design and engineering of the subsea link with a view to completion in 2013 subject to regulatory approval.

Boundary 4: SHETL - SPT

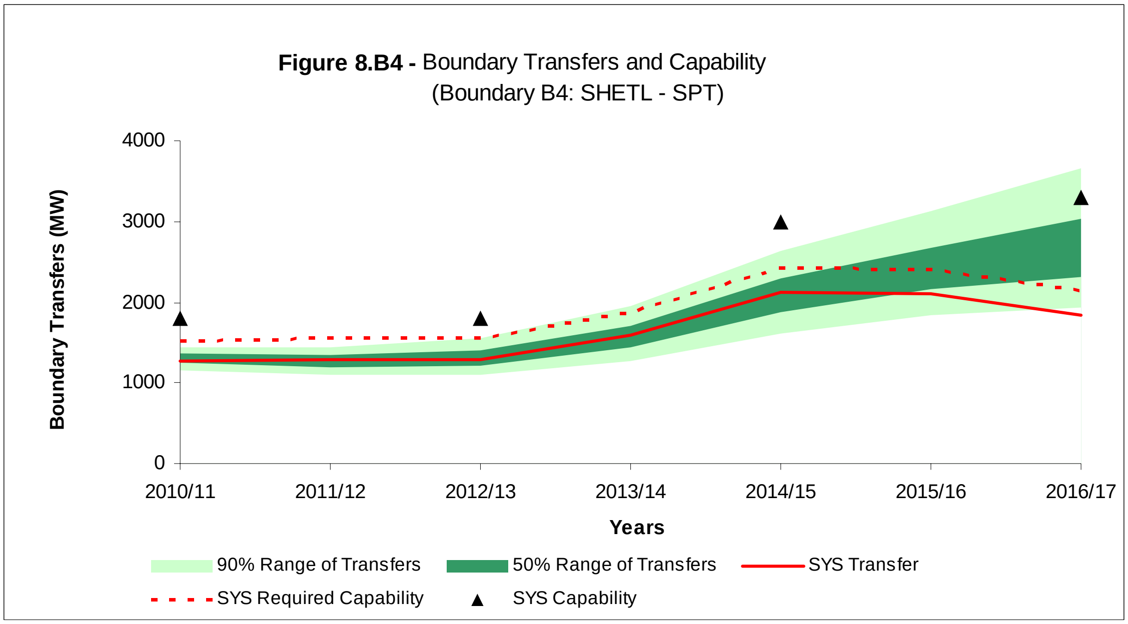


Table 8-T4 - Boundary B4 SHETL – SPT							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
B4E - EXPORT							
Effective Generation	2894	2914	2921	3199	3760	3736	3462
Demand	1632	1628	1628	1608	1639	1630	1615
Planned Transfer	1262	1286	1293	1591	2121	2106	1847
B4I - IMPORT							
Effective Generation	54929	54909	54902	54624	54063	54087	54361
Demand	56191	56195	56195	56215	56184	56193	56208
Planned Transfer	-1262	-1286	-1293	-1591	-2121	-2106	-1847

The SHETL to SPT boundary defines the asset ownership boundary between SHETL and SPT and runs from the firth of Tay in the east to near the head of Loch Long in the west. This boundary encompasses all the generation and demand (except for Dunoon and Strathleven) in the SHETL area and is normally an exporting boundary.

Generation to the north of this boundary is increasing over time due to the high volume of new renewable generation seeking connection in the SHETL area. Consequently, the boundary transfers are also increasing with time.

The application of the Interconnection Allowance (or part thereof) relates only to those boundaries which divide the system into two contiguous parts, the smaller of which contains more than 1500MW of demand. For this boundary, Interconnection allowance is applicable and is added to the Planned Transfer to give the required transfer capability for the boundary.

The increase in the required transfer capability over the seven year period clearly indicates the need to reinforce the transmission system across Boundary 4. The new Inverarnan substation, described under Boundary B3, due for completion in 2010, provides some incremental capacity for Boundary B4 giving a boundary capacity of around 1800MW in 2010/11. The proposed Beauly to Denny reinforcement outlined for the North West boundary, due to be completed in 2013, will increase the capacity of this boundary significantly from 1800MW to around 3000MW by the end of 2013. The Beauly to Denny reinforcement comprises the replacement of the existing 132kV double circuit tower line between Beauly, Fort Augustus, Errochty and Bonnybridge, by a new 400kV double circuit tower line terminating at Denny near Bonnybridge.

It is likely that the increasing volume of renewable generation in the SHETL area will require further reinforcement of this boundary. The next potential reinforcement for this boundary is the 400kV east coast upgrade from Blackhillock to Kincardine using existing infrastructure that is currently operated at 275kV but which is 400kV construction. Currently SHETL are undertaking pre-construction design and engineering of the 400kV east coast project with a view to completion in 2015 subject to an appropriate need case and regulatory approval.

Beyond this, taking account of the potential generation in the period up to and beyond 2020, SHETL and NGET are carrying out pre-construction design and engineering of an offshore HVDC link between Peterhead and the north of England. An estimated completion date for this scheme is 2018 subject to an appropriate need case and regulatory approval.

The undertaking of pre-construction design and engineering work positions the delivery of a project such that construction can commence at the appropriate time when there is confidence that the reinforcement will be required.

Boundary 5: SPT North - South

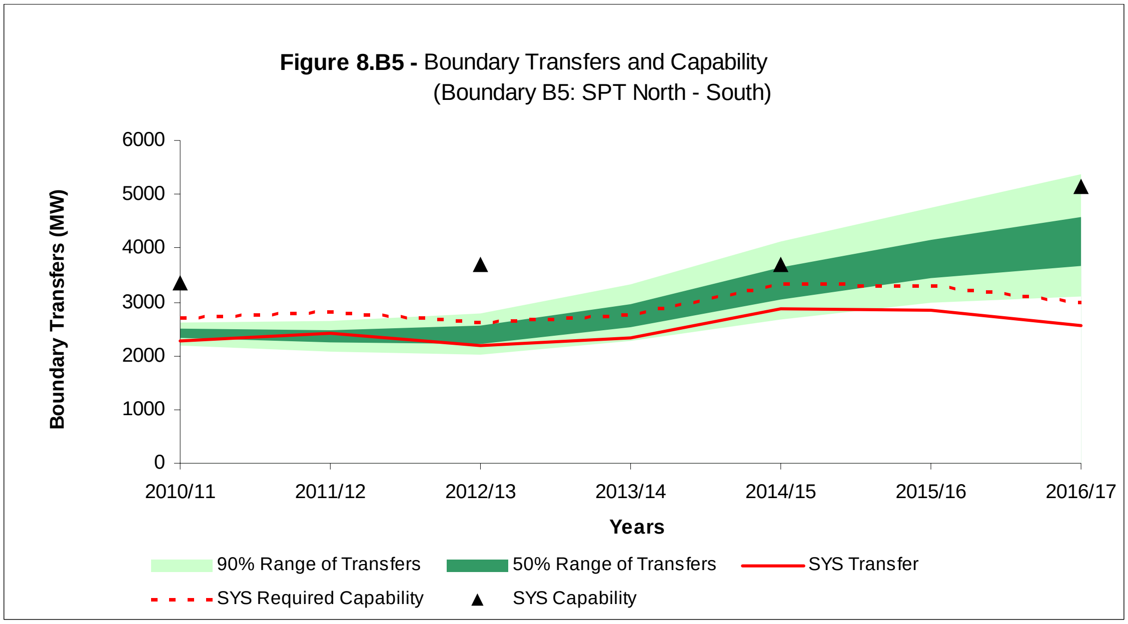


Table 8-T5 - Boundary B5 SPT North – South							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
B5E - EXPORT							
Effective Generation	5140	5257	5035	5187	5766	5746	5422
Demand	2854	2849	2837	2843	2889	2892	2851
Planned Transfer	2286	2408	2198	2344	2877	2854	2571
B5I - IMPORT							
Effective Generation	52683	52566	52788	52636	52057	52077	52401
Demand	54969	54974	54986	54980	54934	54931	54972
Planned Transfer	-2286	-2408	-2198	-2344	-2877	-2854	-2571

The north to south transfer across this boundary in the central belt of Scotland rises through the years of this statement due to contracted renewable energy developments in the north of Scotland. The extent of this rise is reduced in later years however, as some existing generation becomes non-contributory in the SYS background.

Works to reinforce this boundary are in the construction phase. These works will enhance the thermal capability of the Longannet to Clydes Mill and Esterhouse to Clydes Mill 275kV circuits via switchgear replacement at Clydes Mill 275kV substation. A series reactor is being installed at Windyhill 275kV Substation on the Neilston 275kV circuit. These works will deliver a boundary capability of 3400MW by winter 2011/12.

The installation of a second 400/275kV transformer at Strathaven, together with reactive compensation equipment in the SPT area, which form part of a planned upgrade to the SPT-NGET interconnection, will further enhance B5 capability to 3700MW by winter 2012/13.

Taking into account the significant changes anticipated in the generation mix in the period to 2020, SPT is undertaking pre-construction design and engineering work on further upgrades to Boundary B5. Indicative reinforcement, included in SYS Year 7, delivers a boundary capability approaching 5100MW. Undertaking pre-construction engineering work positions the delivery of any project such that construction can commence when there is sufficient confidence that the reinforcement will be required.

Boundary 6: SPT – NGET

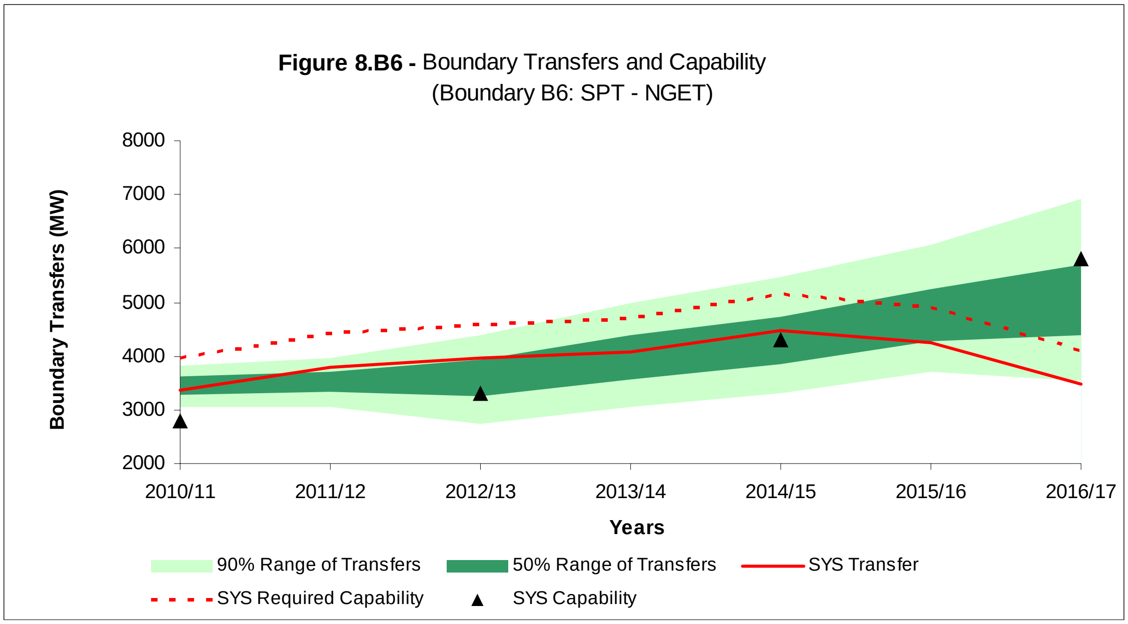


Table 8-T6 - Boundary B6 SPT - NGET							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
B6E - EXPORT							
Effective Generation	9038	9468	9638	9770	10419	10165	9352
Demand	5684	5684	5685	5707	5935	5928	5864
Planned Transfer	3354	3784	3953	4063	4484	4237	3488
B6I - IMPORT							
Effective Generation	48785	48355	48185	48053	47404	47658	48471
Demand	52139	52139	52138	52116	51888	51895	51959
Planned Transfer	-3354	-3784	-3953	-4063	-4484	-4237	-3488

The north to south transfer across the boundary between SPT and NGET rises through the years of this statement, due to contracted renewable energy developments throughout Scotland. As a consequence, the required capability is significantly in excess of the current capability, indicating a strong need for reinforcement. The extent of this rise in later years is reduced as some existing generation becomes non-contributory in the SYS background.

Due to the fact that the required capability currently exceeds the actual capability, SPT and NGET have been granted relief from Licence Condition D3 in respect of the circuits connecting the SPT system to that of NGET.

To achieve a capability of approximately 2,800MW by 2010/11 and 3,300MW by 2012/13, SPT and NGET are undertaking an extensive reinforcement programme. The uprating of the Strathaven to Harker transmission route to double circuit 400kV operation is complete. The overhead line conductor on the Eccles to Stella West 400kV circuits is being replaced during 2010 with a conductor bundle that gives a higher continuous rating and lower impedance, enhancing boundary thermal and stability performance. New transformers will be installed at Blyth connecting into the Eccles to Stella West circuits. Strathaven will be reconfigured and reactive compensation will be installed at a number of strategic locations on the SPT network.

Upon completion of the works above, this boundary continues to show insufficient transfer capability for the given SYS Background, indicating further reinforcement is required.

Taking into account the significant changes anticipated in the generation mix in the period to 2020, SPT and NGET are undertaking pre-construction design and engineering work on further upgrades to Boundary B6. These include series compensation and offshore HVDC schemes, which have been incorporated into the SYS background and together deliver a capability approaching 5800MW by 2015/16. Undertaking pre-construction engineering work positions the delivery of any project such that construction can commence when there is sufficient confidence that the reinforcement will be required.

Boundary 7: NGET Upper North

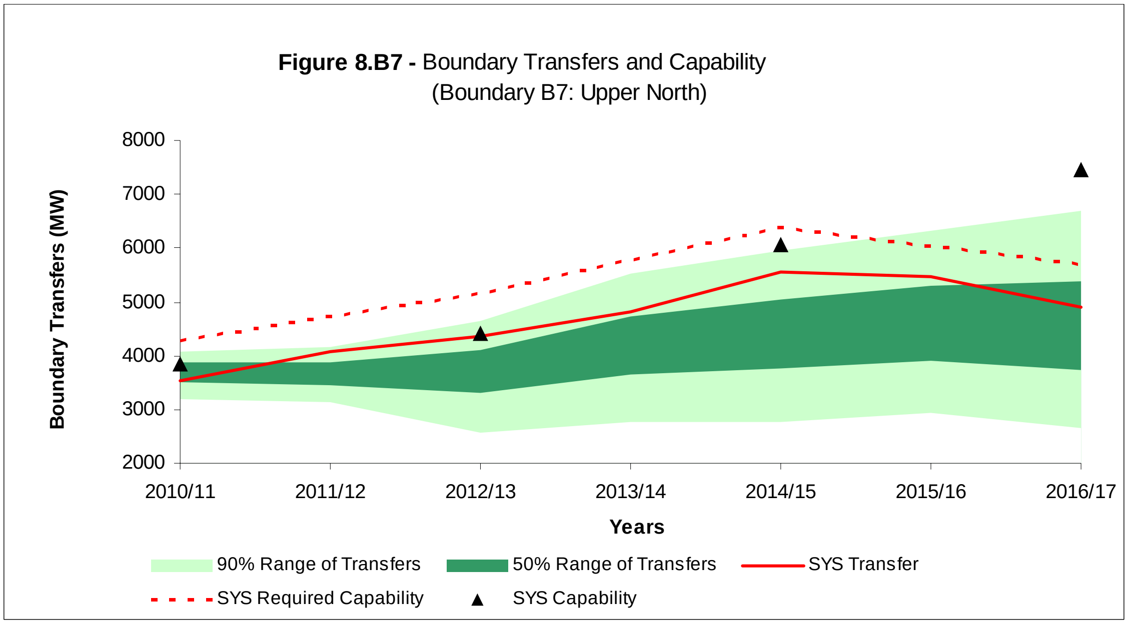


Table 8-T7 - Boundary B7 NGET Upper North							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
B7E - EXPORT							
Effective Generation	11957	12465	12737	13226	14204	14006	13271
Demand	8432	8394	8364	8404	8647	8543	8370
Planned Transfer	3525	4071	4373	4822	5556	5463	4901
B7I - IMPORT							
Effective Generation	45866	45358	45086	44597	43619	43817	44552
Demand	49391	49429	49459	49419	49176	49280	49453
Planned Transfer	-3525	-4071	-4373	-4822	-5556	-5463	-4901

The boundary transfer in the upper north region tends to increase over the years from new northern renewable generation, but then decreases in 2016/17 due to the expected closure of Cockenzie coal fired power plant. The required capability continues to grow up to 2014/15 and reinforcements are being progressed in response to this. This is indicated by an increase in SYS capability in this period that lie on the high percentile of probabilistic transfers. In 2016/17, the installation of the HVDC link from Deeside to Hunterston in 2015 provides additional capability sufficient to meet the requirements.

In subsequent years beyond the SYS period, required capabilities continue to grow with the increase of generation north of the boundary.

Boundary 8: NGET North to Midlands

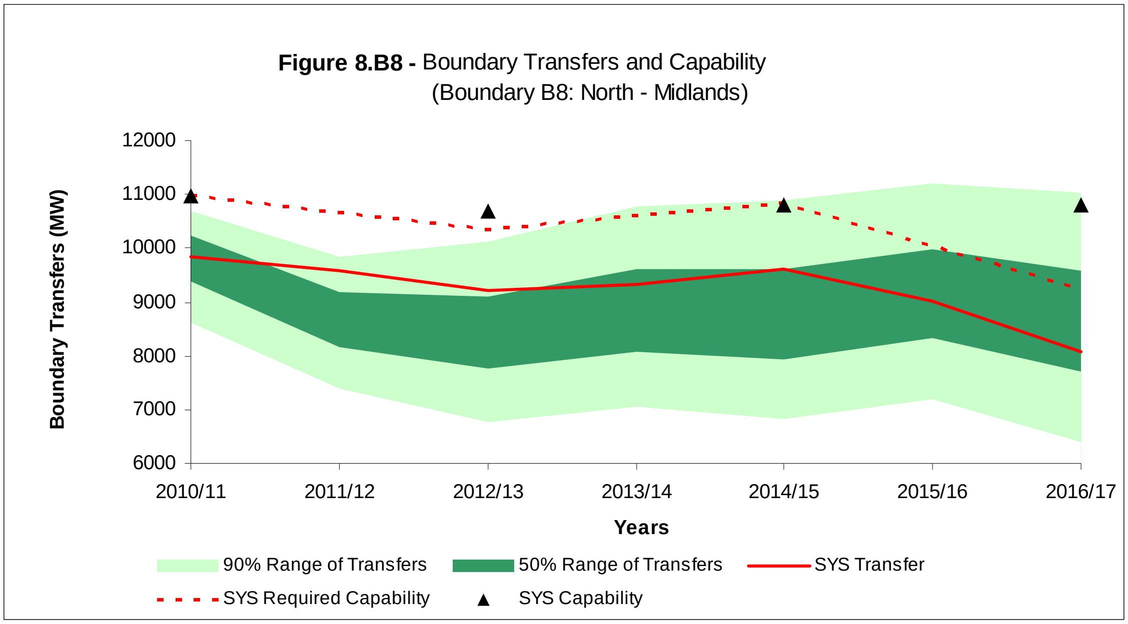


Table 8-T8 - Boundary B8 NGET North – Midlands							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
B8E - EXPORT							
Effective Generation	31284	30891	30416	30635	31217	30501	29335
Demand	21438	21306	21216	21313	21603	21493	21255
Planned Transfer	9846	9584	9200	9322	9615	9008	8080
B8I - IMPORT							
Effective Generation	26539	26932	27407	27188	26606	27322	28488
Demand	36385	36517	36607	36510	36220	36330	36568
Planned Transfer	-9846	-9584	-9200	-9322	-9615	-9008	-8080

The North to Midlands boundary transfers fluctuate around 10GW as generation changes output north and south of the boundary. A more pronounced drop is seen in the year 2016/2017 which can be explained by the LCPD closure of northern generating units and other thermal generators falling out of merit.

SYS boundary capability stays fairly constant throughout the period with no significant reinforcements planned. However, it is worth noting that fluctuations in the boundary capability can be seen with changes in generation conditions.

Boundary 9: NGET Midlands to South

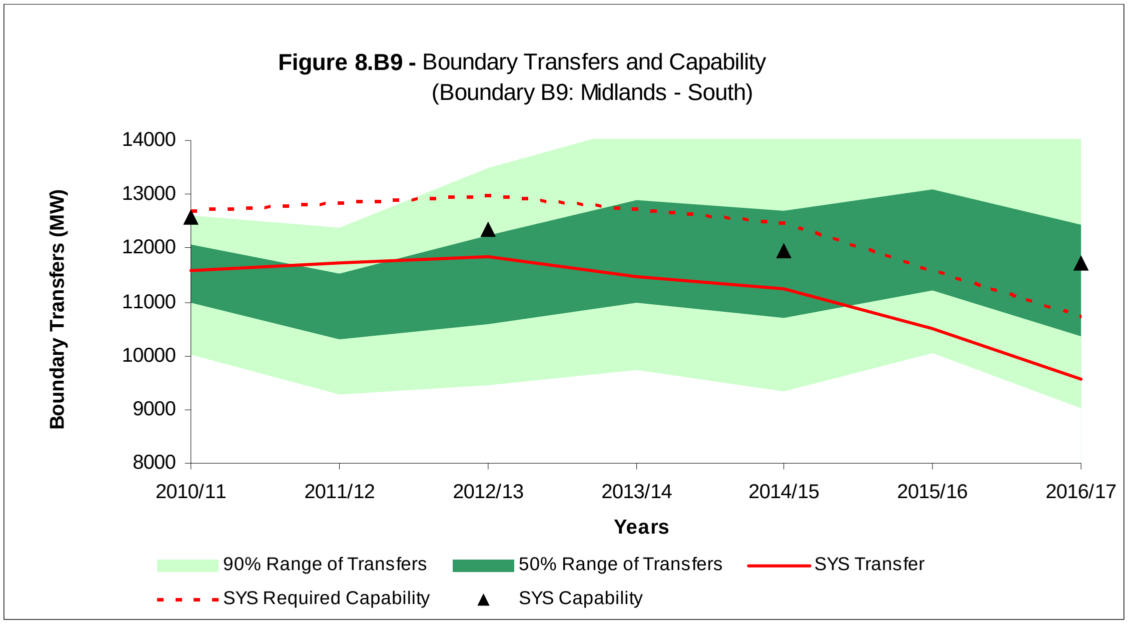


Table 8-T9 - Boundary B9 Midlands – South							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
B9E - EXPORT							
Effective Generation	40318	40500	40676	40389	40399	39575	38352
Demand	28736	28761	28846	28914	29169	29064	28797
Planned Transfer	11582	11739	11829	11475	11230	10512	9555
B9I - IMPORT							
Effective Generation	17505	17323	17147	17434	17424	18248	19471
Demand	29087	29062	28977	28909	28654	28759	29026
Planned Transfer	-11582	-11739	-11829	-11475	-11230	-10512	-9555

The Midlands to South boundary transfers remain fairly constant until 2016 when there is a significant reduction in transfer; this reduction can be attributed to LCPD closures similar to other boundaries.

The boundary capability is slightly below the required transfers in 2010 and 2012 but the probabilisitic ranges indicate that the required capabilities are sitting on the high percentile of the probabilistic range. Some indicative reinforcements have been identified but this will be reviewed and progressed in due course. It is also worth noting that as a result of the southern connecting generation in 2014 and 2016 the required transfers reduce and boundary capability becomes complaint .

Boundary 10: NGET South Coast

Figure 8.B10 - Boundary Transfers and Capability (Boundary B10: South Coast)

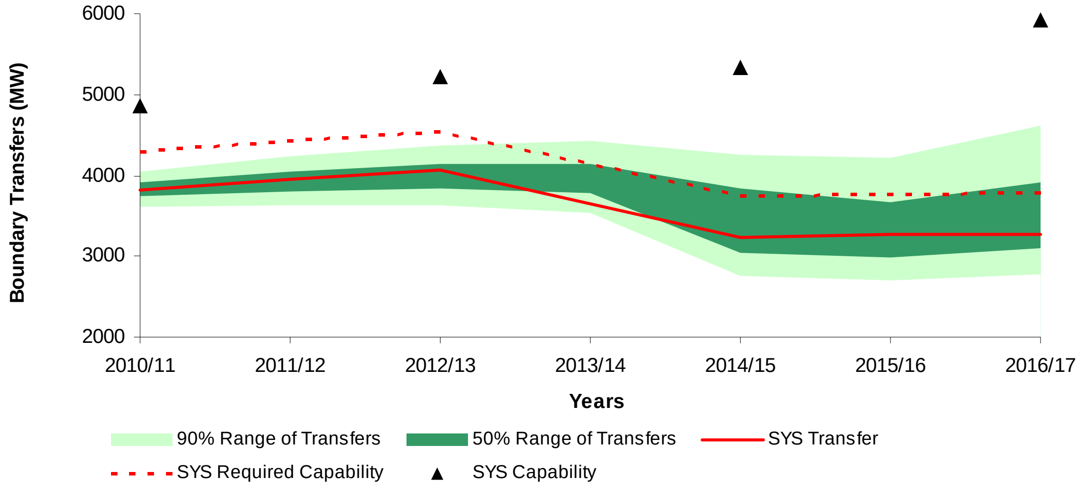


Table 8-T10 - Boundary B10 NGET South Coast							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
B10E - EXPORT							
Effective Generation	2996	2789	2607	3016	3400	3366	3351
Demand	6816	6737	6676	6656	6632	6644	6627
Planned Transfer	-3820	-3948	-4069	-3641	-3232	-3278	-3276
B10I - IMPORT							
Effective Generation	54827	55034	55216	54807	54423	54457	54472
Demand	51007	51086	51147	51167	51191	51179	51196
Planned Transfer	3820	3948	4069	3641	3232	3278	3276

The South Coast boundary imports power from North - South feeding the high demands along the South Coast. The SYS transfer remains fairly constant from 2010/11with a marginal increase in 2012/13, mainly due to steady demand growth in the area.

The system transfer begins to reduce from 2012/13 onwards due to new generation openings in the south coast area. The probabilistic range of transfers sits below planned and required transfers in the early years due to an assumed output from normally non-contributory generation.

Boundary 11: NGET North East and Yorkshire

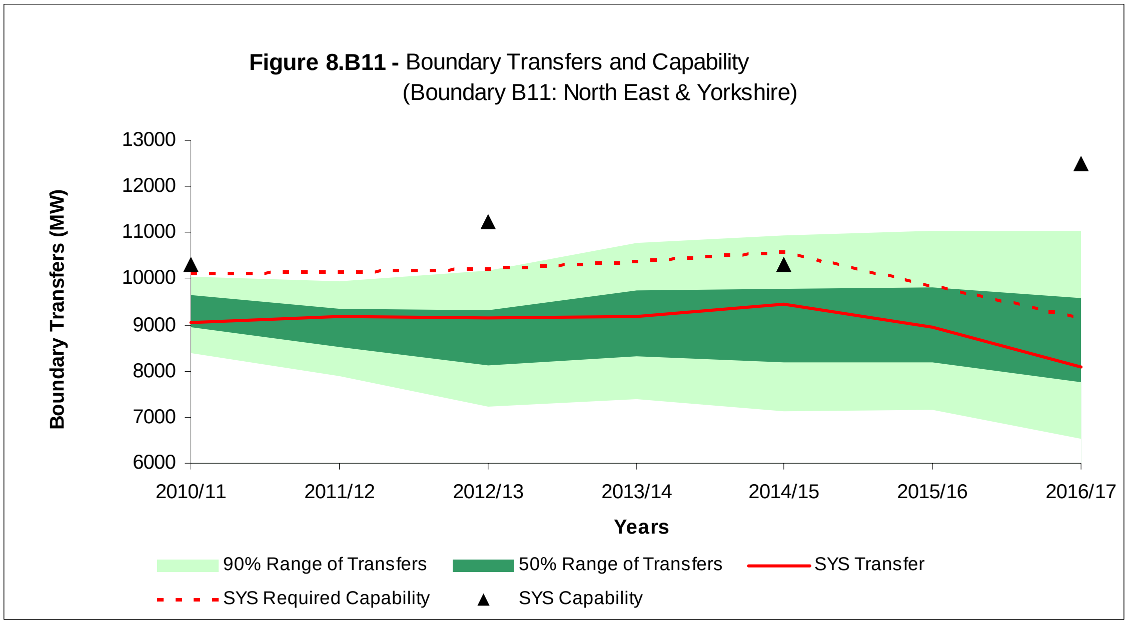


Table 8-T11 - Boundary B11 NGET North East & Yorkshire							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
B11E - EXPORT							
Effective Generation	23284	23235	23040	23242	23861	23279	22209
Demand	14218	14049	13902	14055	14407	14311	14119
Planned Transfer	9066	9186	9139	9186	9454	8969	8090
B11I - IMPORT							
Effective Generation	34539	34588	34783	34581	33962	34544	35614
Demand	43605	43774	43921	43768	43416	43512	43704
Planned Transfer	-9066	-9186	-9139	-9186	-9454	-8969	-8090

The Northeast and Yorkshire boundary remains fairly constant until a significant drop in the year 2016/2017 which can be explained by LCPD closures and some older generating units coming out of merit, north of the boundary.

SYS capability is higher than the required capability in 2010 and 2012 but slightly lower in 2014/15. There is an increase in SYS capability in 2016/2017, due to planned reinforcements for the B6 boundary, such as the West coast HVDC link.

In subsequent years beyond the SYS period, required capabilities continue to grow with the increase of generation north of the boundary.

Boundary 12: NGET South & South West

Figure 8.B12 - Boundary Transfers and Capability (Boundary B12: South & South West)

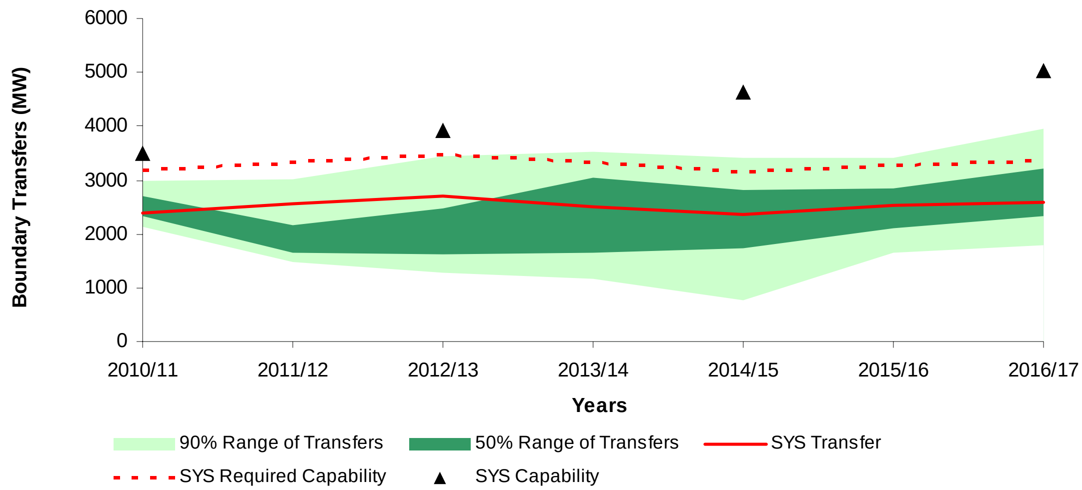


Table 8-T12 - Boundary B12 NGET South & South West							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
B12E - EXPORT							
Effective Generation	9231	8959	8761	8936	9044	8912	8829
Demand	11631	11532	11463	11441	11411	11433	11404
Planned Transfer	-2400	-2573	-2702	-2506	-2367	-2521	-2576
B12I - IMPORT							
Effective Generation	48592	48864	49062	48887	48779	48911	48994
Demand	46192	46291	46360	46382	46412	46390	46419
Planned Transfer	2400	2573	2702	2506	2367	2521	2576

This is an importing boundary with the SYS capability remaining firmly above the SYS required capability. The boundary is already strong with many parallel circuit routes and sufficient local generation support. A number of new CCGT generators south of the boundary together with their local connection works increases the boundary capability throughout the SYS period. The transfer across the boundary is not expected to change much as the generation and demand balance remains fairly constant.

Boundary 13: NGET South West

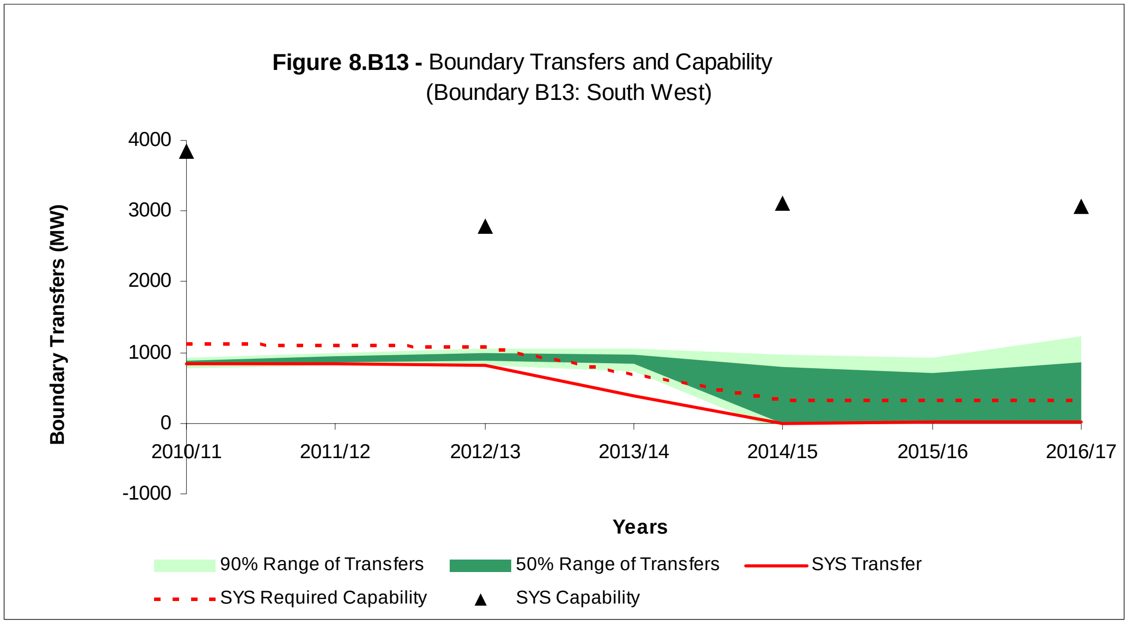


Table 8-T13 - Boundary B13 NGET South West							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
B13E - EXPORT							
Effective Generation	1757	1734	1725	2140	2537	2511	2500
Demand	2605	2567	2535	2529	2522	2528	2524
Planned Transfer	-848	-833	-811	-390	15	-17	-24
B13I - IMPORT							
Effective Generation	56066	56089	56098	55683	55286	55312	55323
Demand	55218	55256	55288	55294	55301	55295	55299
Planned Transfer	848	833	811	390	-15	17	24

SYS transfer remains relatively unchanged close to neutral due to a close balance of local generation and demand. The connection of a new offshore windfarm drops the boundary flow very close to neutral in 2014. The North – South capability of the boundary significantly exceeds the SYS requirements.

The position shown in the Seven Year Statement is one year in advance of the connection of Hinkley Point C. This power station shall have a capacity of 3.3GW and shall represent a significant increase in capacity in the area, giving rise to a change in the export condition this change shall be reflected in future years statements. It should also be noted along the Offshore Development Information Statement has identified further offshore wind capacity hoping to connect in the region.

Boundary 14: NGET London

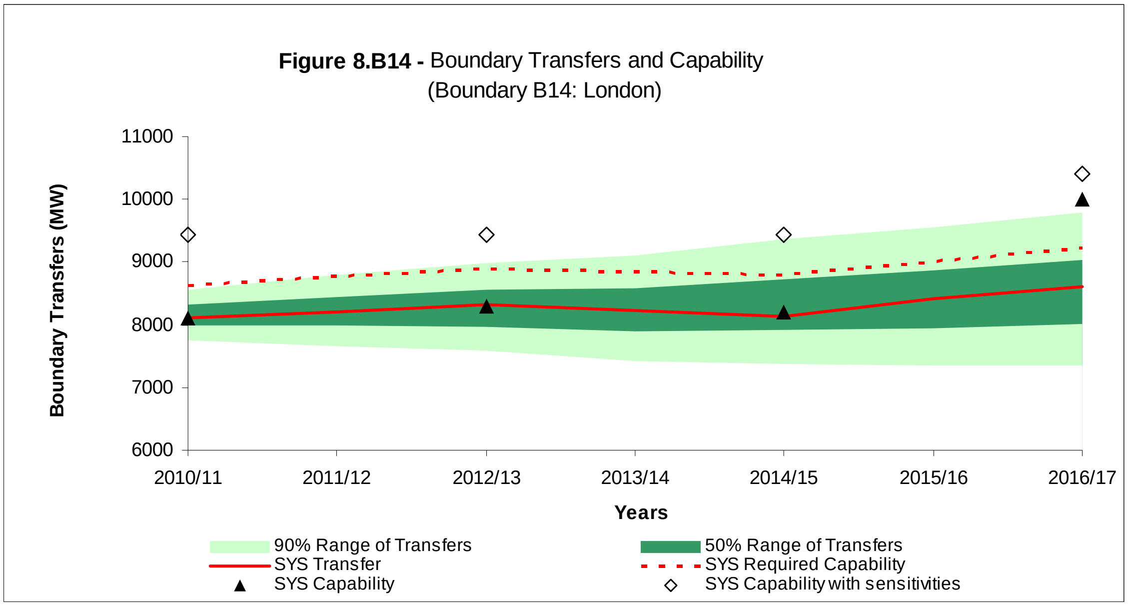


Table 8-T14 - Boundary B14 NGET London							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
B14E - EXPORT							
Effective Generation	1723	1700	1691	1863	2021	1846	1679
Demand	9824	9902	10005	10089	10165	10252	10294
Planned Transfer	-8101	-8202	-8314	-8226	-8143	-8406	-8615
B14I - IMPORT							
Effective Generation	56100	56123	56132	55960	55802	55977	56144
Demand	47999	47921	47818	47734	47658	47571	47529
Planned Transfer	8101	8202	8314	8226	8143	8406	8615

London is characterised as a low generation and high demand boundary. It therefore relies on importing power across a number of critical circuits. The capabilities for London are extremely sensitive to both the French interconnectors (importing and exporting) and generation in a given region. In the SYS background there is no southern power support for London due to both European interconnectors exporting to the continent, and this is characterised by low SYS capabilities. The SYS capabilities with sensitivities is therefore also quoted in the graph above to better reflect the interconnector and generation sensitivities.

In 2016/17 the SYS capability increases, due to the following reinforcements:

- Waltham Cross to Tottenham 400 kV upgrade
- Re-conductoring of the Barking - Northfleet East 400kV double circuit route

For a detailed summary of reinforcements, please refer to Table B.7c.

Boundary 15: NGET Thames Estuary

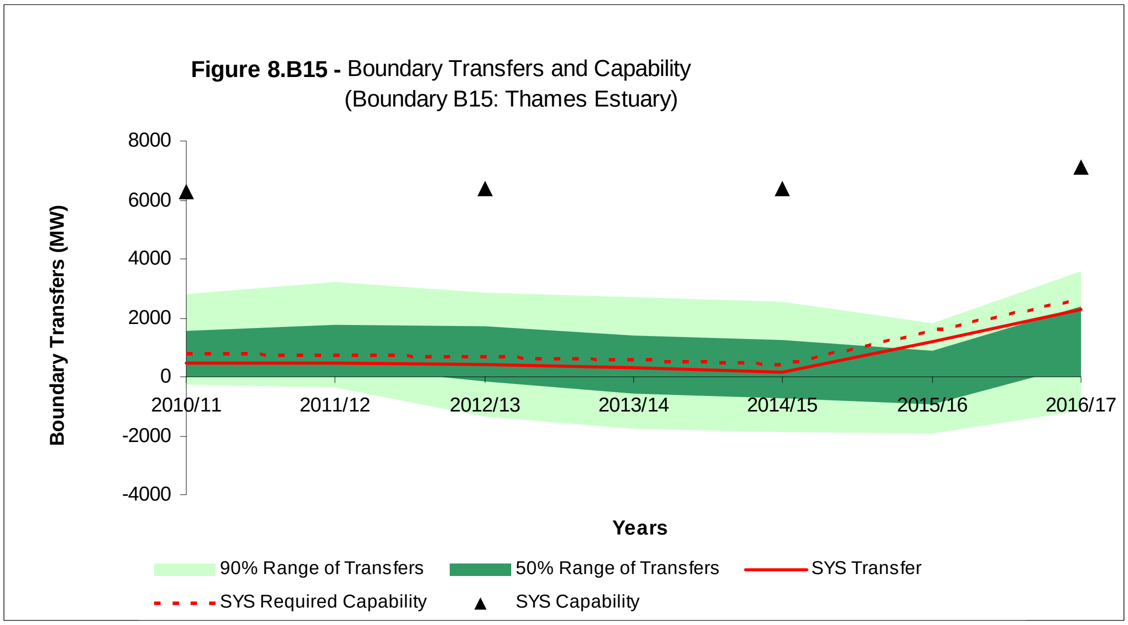


Table 8-T15 - Boundary B15 NGET Thames Estuary							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
B15E - EXPORT							
Effective Generation	2497	2457	2438	2316	2178	3217	4281
Demand	2004	2013	2028	2022	2016	2008	1992
Planned Transfer	493	444	410	294	163	1209	2289
B15I - IMPORT							
Effective Generation	55326	55366	55385	55507	55645	54606	53542
Demand	55819	55810	55795	55801	55807	55815	55831
Planned Transfer	-493	-444	-410	-294	-163	-1209	-2289

The Thames Estuary transfers are heavily dependant on the assumed flows on the continental interconnectors. With the high plant margin in the SYS background the interconnectors are expected to mostly export to the continent which massively reduces the exports from the Thames Estuary towards London. This is shown by the low required capabilities between 2010/11 and 2014/15. The boundary also has to manage flows when the interconnectors are importing from the continent. In these cases, the boundary transfer can increase to more than 6GW.

A number of coal fired generating plants within the boundary are expected to either close or drop out of merit during the SYS period. New renewable and CCGT generators are expected to connect within the SYS period and in the last year of SYS couple of significant clean coal generators are planned to come online, thus increasing export transfers. Beyond the SYS period large new nuclear generators are expected to connect close to the boundary which will require significant reinforcement works.

Boundary 16: NGET North East, Trent & Yorkshire

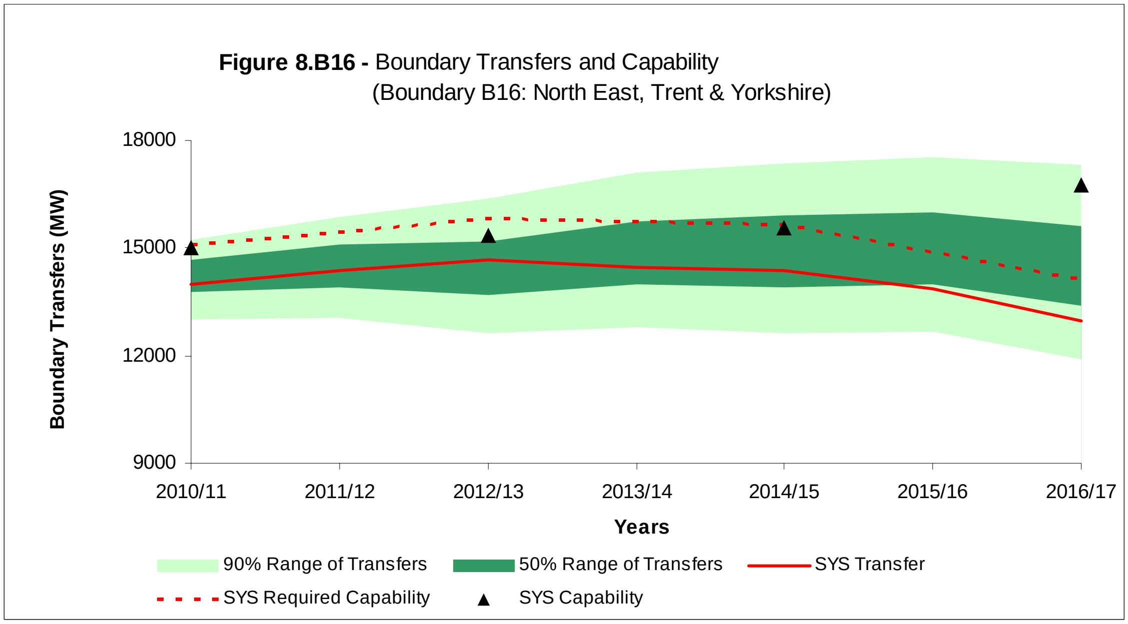


Table 8-T16 - Boundary B16 NGET North East, Trent & Yorkshire							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
B16E - EXPORT							
Effective Generation	28921	29159	29298	29212	29501	28864	27769
Demand	14923	14765	14633	14772	15109	15003	14799
Planned Transfer	13998	14394	14665	14439	14392	13861	12970
B16I - IMPORT							
Effective Generation	28902	28664	28525	28611	28322	28959	30054
Demand	42900	43058	43190	43051	42714	42820	43024
Planned Transfer	-13998	-14394	-14665	-14439	-14392	-13861	-12970

The transfers across boundary 16 (North East, Trent & Yorkshire) do not vary tremendously, remaining consistent throughout 2010-2014 with a gradual increase due to contracted renewable energy development in 2016. The transmission capability is slightly lower than the required transfer in 2012, which is due to a thermal overload on boundary crossing circuits.

The significant drop in transfers in 2016/17 can be explained by the LCPD closure of generating units and other thermal generators falling out of merit from north of the boundary. The SYS capability increases in 2016/17 due to a number of reinforcements being implemented i.e. the West Coast HVDC link.

Boundary 17: NGET West Midlands

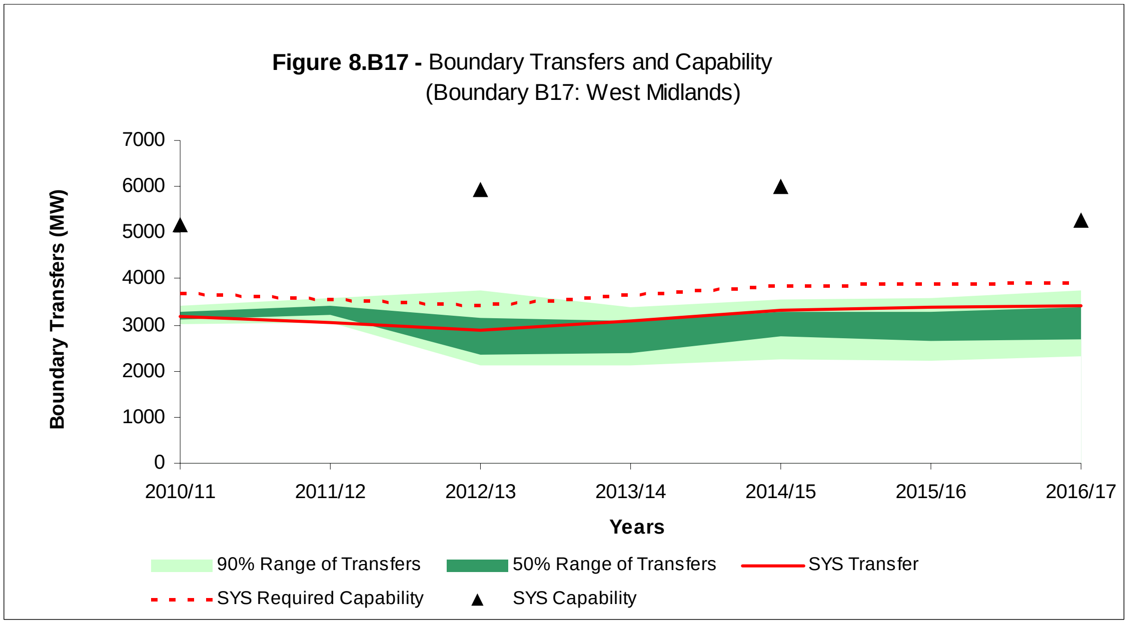


Table 8-T17 - Boundary B17 NGET West Midlands							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
B17E - EXPORT							
Effective Generation	3397	3685	4002	3785	3541	3490	3457
Demand	6594	6738	6899	6884	6864	6878	6862
Planned Transfer	-3197	-3053	-2897	-3099	-3323	-3389	-3405
B17I - IMPORT							
Effective Generation	54426	54138	53821	54038	54282	54333	54366
Demand	51229	51085	50924	50939	50959	50945	50961
Planned Transfer	3197	3053	2897	3099	3323	3389	3405

The West Midlands has a lack of local generation requiring power imports to meet demand and supports the bulk North to South power flows on the transmission system. The transfer drops a little in 2012/13 from new generation connections in this importing area. The transfer then increases gradually until 2016/17, largely because of the increasing North to South power flows.

The boundary capability is higher than the requirement determined by the SYS background throughout the whole period.

Indicative Reinforcements for licence compliance

The list of reinforcement schemes presented in Table 8.2 provides an indication of those reinforcements that may be required to ensure continued compliance with the Licence Standard across the 17 major SYS boundaries at the time of peak for the given SYS background, i.e. to remedy capability deficits.

These indicative schemes would be additional to the currently planned transmission reinforcements listed in Tables B.7a, B.7b and B.7c, and which already form part of the SYS background.
The additional schemes would be required, not only for compliance across the 17 SYS boundaries ('inter-zonal' reinforcements), but also for compliance across a number of boundaries internal to the zones delineated by the 17 SYS boundaries ('intra-zonal' reinforcements). The developments listed are those required for the specific SYS background. The additional indicative schemes would be varied to meet the changing needs of the system as it evolves.

Once the need for a particular reinforcement is established the detailed specification will be considered. By way of example, for reactive compensation plant, the optimal location, size and desired performance will be the subject of detailed analyses nearer the time when there is a need to commit to the work.

Some of the works listed in Table 8.2 will have been made a condition of particular 'GB Agreements' for connection to and use of the national electricity transmission system. That is, a condition will have been included in certain agreements stipulating that the works would have to be completed before connection to or use of the national electricity transmission system is permitted. This is in order to ensure continued compliance of the system with the Licence Standard and to safeguard the interests of all Users of the national electricity transmission system in respect of security of supply.

Indicative Reinforcements required to meet Environmental Targets

In June 2008, the Government published its consultation on a UK Renewable Energy Strategy. Following on from this, the Electricity Networks Strategy Group (ENSG), a cross industry group jointly chaired by the Department of Energy and Climate Change and Ofgem, asked the three electricity GB Transmission Licensees, National Grid, Scottish Hydro Electric Transmission and Scottish Power Transmission with the support of an Industry Working Group to take forward a study to:

1. Develop electricity generation and demand scenarios consistent with the EU target for 15% of the UK's energy to be produced from renewable sources by 2020 (this scenario was developed in the second half of 2008 and has subsequently been updated, as shown above, however, the small changes to the progress of wind, predominately offshore, will have no material affect on the results of the ENSG work).

2. Identify and evaluate a range of potential electricity transmission network solutions that would be required to accommodate these scenarios.

In July 2009, ENSG published a report 'Our Electricity Transmission Network: A Vision For 2020':

http://www.ensg.gov.uk/assets/ensg_transmission_pwg_full_report_final_issue_1.pdf

which discharged the action placed on the Transmission Licensees. The reinforcements identified in this report are based on a range of scenarios that take account of the significant changes anticipated in the generation mix between now and 2020. In particular, the scenarios examined the potential transmission investments with the connection of large volumes of onshore and offshore wind generation required to meet the 2020 renewables target, whilst, at the same time, facilitating the connection of other essential new generation, such as new nuclear that will be needed to reduce carbon emissions and maintain continued security of supply.

The study concluded that, provided the identified reinforcements are taken forward in a timely manner, they can be delivered to required timescales. It should also be noted that the reinforcements identified in this report are designed to facilitate connection of a large volume of different types of generation in a given area, not dependent on a single generation project proceeding, and where the lead time for the combined transmission reinforcements in a given area would exceed the time taken to construct the generation, i.e. lack of transmission capacity would have a potential negative impact in meeting renewable targets and/or accommodating generation required to maintain continued security of supply.

The development of the potential reinforcements are phased to achieve a 2020 delivery date with the initial phase being delivered in 2015 based on the prospective growth of renewables in each region. It is recognised that there will continue to be a degree of uncertainty about the volume and timing of generation growth in any given area. It is therefore proposed to continue to monitor the development of the market and update the scenarios accordingly. The proposed transmission reinforcements will be developed in such a manner as to ensure that the options are maintained at minimum costs. By undertaking pre-construction engineering work, the delivery of each project can be positioned such that construction can be commenced when there is sufficient confidence that the proposed reinforcements will be required. This is the least regrets solution, i.e. the minimum commitment to secure the ability to deliver to required timescales.

Ofgem have initiated a further consultation with regards to funding which will facilitate taking forward the reinforcements identified in the report. In their initial proposals, Ofgem reiterated their commitment to ensuring adequate funds are made available to ensure timely investment is undertaken. Earlier in 2010, funds were made available to take forwards for all the pre-construction works identified in the report. A further submission to Ofgem will be made in late summer 2010 seeking funding for projects commencing construction in 2011/12 and 2012/13.

Table 8.1 - GUM Boundaries Defined by SYS Study Zone		
Boundary Number	**Boundary Name**	**SYS Study Zone/s (one side of boundary)**
B1	North West Export	Z1
B2	North-South	Z1, Z2
B3	Sloy Export	Z3
B4	SHETL-SPT Boundary	Z1, Z2, Z3, Z4
B5	North-South	Z1, Z2, Z3, Z4, Z5
B6	SPT-NGET Boundary	Z1, Z2, Z3, Z4, Z5, Z6
B7	Upper North-North	Z1, Z2, Z3, Z4, Z5, Z6, Z7
B8	North to Midlands	Z1, Z2, Z3, Z4, Z5, Z6, Z7, Z8, Z9
B9	Midlands to South	Z1, Z2, Z3, Z4, Z5, Z6, Z7, Z8, Z9, Z10, Z11
B10	South Coast	Z16, Z17
B11	North East & Yorkshire	Z1, Z2, Z3, Z4, Z5, Z6, Z7,Z8
B12	South & South West	Z13, Z16, Z17
B13	South West	Z17
B14	London	Z14
B15	Thames Estuary	Z15
B16	North East, Trent & Yorkshire	Z1, Z2, Z3, Z4, Z5, Z6, Z7, Z8, Z10
B17	West Midlands	Z11

Table 8.2 Indicative Developments		
Location	**Works**	**Affected Boundaries/Licensee**
Higm Marnham - Ratcliffe	Increase the rating on the High Marnham to Ratcliffe circuits	NGET
Ratcliffe - Staythorpe	Increase the rating of the Ratcliffe to Staythorpe circuit	NGET
Grendon – West Burton	Increase the rating of the Grendon to West Burton circuit	NGET
Cottam	Install reactive compensation, 1 MSC	NGET
Staythorpe	Install reactive compensation, 1 MSC	NGET
Ratcliffe on Soar	Install reactive compensation, 1 MSC	NGET
Pelham	Install reactive compensation, 1 MSC	NGET

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Chapter 9

Opportunities

Introduction

This chapter provides a commentary on those parts of the national electricity transmission system most suited to new connections and to the transport of further quantities of electricity. The information presented draws on that contained in the previous chapters, in particular Chapter 8 (Transmission System Capability).

Readers are reminded that anyone considering a development at a specific site and requiring additional technical information relating to that site may contact us for assistance as explained in "Further Information" in Chapter 1.

Notwithstanding the opportunities set out in this chapter, the three Transmission Licensees will continue to comply with Transmission Licence obligations and make offers to any User or potential new User wishing to use the national electricity transmission system in respect of new generation and/or demand. The timescales, required by each Transmission Licensee to complete any necessary transmission work, associated with a new development, is, amongst other things, a function of the size and location of the development. In some instances no infrastructure reinforcement work at all will be required and no delay will be incurred. That is, if the required transmission reinforcement is localised and not environmentally contentious, the necessary work can normally be completed in similar timescales to that of the customer's project. However, where the development requires extensive and/or contentious transmission work (with the associated need for Planning Consent and possible Public Inquiries), it may not always be possible for the relevant Transmission Licensee to fully meet the customer's wishes with respect to timescales. Nevertheless, all three Transmission Licensees will always endeavour to meet their customer's requirements.

Finally, the provision of voltage support services is discussed towards the end of this chapter. Amongst other things this section presents information on possible future opportunities for Users to provide voltage support services under contract to ourselves and outline information on performance requirements for such services to help Users decide whether to approach us with an offer of service.

Use of External Interconnections

Introduction

The section on "Interconnections with External Systems" in Chapter 3 explained that our transmission system is directly interconnected with those of France, Northern Ireland and the Netherlands by the end of 2010. Parties that have acquired rights to use these External Interconnections are, subject to the relevant market arrangements and agreements, able to trade between the electricity market in Great Britain and those of the External Systems.

France Link

Under NETA, new arrangements for obtaining access to the link were introduced and these continue under BETTA. The arrangements allow for capacity to be allocated in either direction via a system of auctions. These are jointly administered by National Grid and the French Transmission System Operator (RTE). Details of the access arrangements including the auction process can be found on the RTE and National Grid Website, namely: http://www.nationalgrid.com/uk

Northern Ireland Link

This link is owned by Moyle Interconnector Limited and operated by System Operator Northern Ireland (SONI), who also administer the sale of capacity on the interconnector on behalf of Moyle. The relevant Website address is: http://www.soni.ltd.uk

Netherlands Link

National Grid and NLink, a subsidiary of TenneT, the transmission system operator in the Netherlands, are developing a project for an interconnector between Britain and the Netherlands. Access is open to all market participants through explicit and implicit auctions.

Eire Link

Eirgrid is developing an 500MW HVDC interconnecter to join Eire to the NGET network at Deeside. The interconnector is proposed for connection in 2011.

New Demand

The majority of single new demands are less than 50MW in size (e.g. a large new car production plant). However, the demand from a new steelworks could be in the region of 150MW. In any event, a step-change of say 150MW of demand is usually too small a value to affect any single zone significantly. In general terms, there is likely to be sufficient spare capability over a whole zone of the supergrid to be able to accommodate any single new demand of this size without requiring major reinforcement into the whole zone. Reinforcements at and into a particular Grid Supply Point may be required for a new demand, and in some cases additional reactive compensation may also be required, and a prospective new entrant should contact us for a detailed discussion of an individual site.

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 system peak demand. The London boundary is close to its thermal limit although planned work, some in Table B.7c and some in Table 8.2, will ensure continued compliance. A large step-change in demand might, dependent on exact location, require major reinforcement.

It should also be remembered that, whilst a 150MW demand increase may not have an appreciable effect upon the particular zone in which it is located, it could have a more global effect on the overall system. For instance additional demand in the south could, under certain circumstances, advance the need for major inter zonal transmission reinforcement between the north and the south. Each case needs to be considered on its own merits.

New Generation

Overview

In general terms, the disposition of demand and generation across the national electricity transmission system is such that much of the generation capacity is located in or towards the northern parts while much of the demand is located in the southern parts of the system. In consequence, the resultant power flows are broadly from the northern parts to the southern parts of the system, particularly at times of the system peak demand.

The disposition of the reported increase in generating capacity from 2009/10 to 2016/17 is described in ”Generation Disposition” in Chapter 3. In particular, Table 3.11 details the capacity changes on a zonal basis.

It should be remembered that the figures shown in tables such as Table 3.11 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.

It should also be noted that capacities in Table 3.11 and other tables in Chapter 3 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 Chapter 4 (Embedded and Renewable Generation).

A key message arising from the analyses of boundary power transfers is that, with the increase in new generation planned over the next seven years, the resultant power flows through the Scottish and English grid systems to the Midlands would require significant reinforcement. The future is uncertain and it may be that not all projects may proceed to completion. In addition some existing fossil fuel stations may close due to technical or commercial reasons, or due to environmental legislation, e.g. following the introduction of the Large Combustion Plant Directive in 2008.

Generation Opportunities

The diagram in Figure 9.1 is intended to provide an indication of the opportunities for the connection of new generation to a compliant network, across the 17 SYS Study Zones. These 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.

In Figure 9.1, the 17 SYS Study Zones have been grouped into five opportunity groups, namely: VERY LOW, LOW, MEDIUM, HIGH and VERY HIGH. These categorisations are intended to provide a broad indication of the relative level of possible opportunities for connection within individual zones, or groups of zones, without the need for further major inter-zonal transmission reinforcement, which would be likely to incur significant delays in the proposed project.

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 (zone 14), 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. The red areas in Figure 9.1 would imply limited opportunity for connection in those zones given the level of transmission reinforcement required.

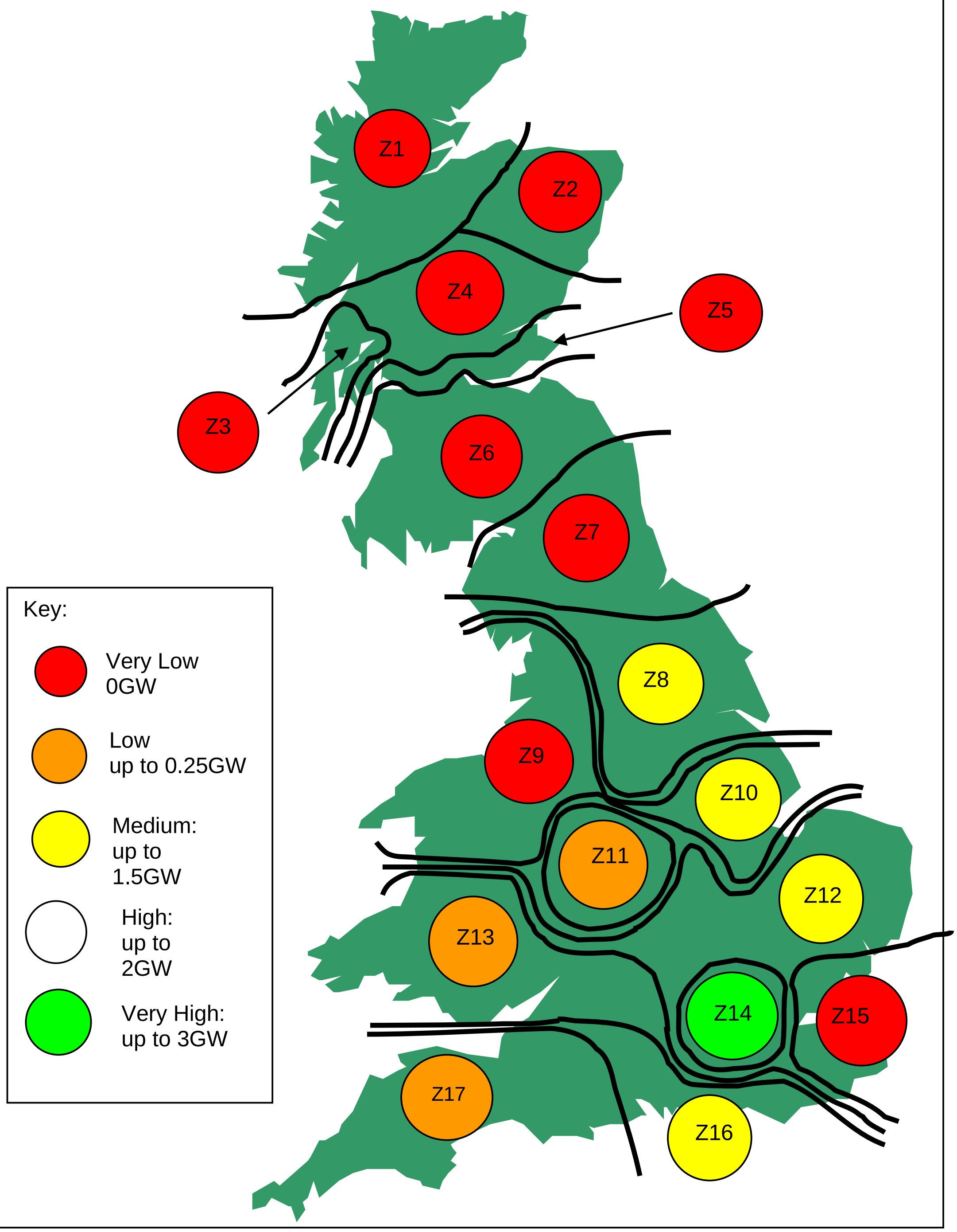
Whilst Figure 9.1 correctly represents the opportunity for connection to a compliant network, it should be noted that Ofgem’s open letter dated 8th May 2009 provides the opportunity for new generation projects to connect under a derogation in advance of the wider system reinforcements being delivered. 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.

Until recently, GB generation agreements have been conditional on the completion of any necessary reinforcements to maintain compliance with the Licence Standard. Under the new arrangements it is now possible to connect new generation projects without all the necessary works in place, subject to appropriate derogations being received. The sections on “Transmission Access Review” and “Interim Connect and Manage” later in this chapter provide more details of the current arrangements.

The proposed connection of a significant volume of new transmission contracted generation in the SHETL area, substantially made up of wind farms, has caused the SYS background power flows across major boundaries within Scotland to increase over the period of the SYS. This has resulted in a number of transmission reinforcements being planned to achieve the necessary boundary capacities. These schemes include the planned Beauly/Denny transmission reinforcement. The Beauly/Denny reinforcement is included as part of the SYS background for commissioning by 2013/14 following the successful completion of a Public Inquiry in January 2010.

There are also a number of reinforcements planned for the SPT-NGET boundary (Boundary B6), where there would appear to be insufficient transmission capacity to accommodate the level of contracted generation in Scotland.

Figure 9.1 - GB Generation Connection Opportunities



A consequence of the connection of 'contracted' generation in Scotland is that there is insufficient capacity on some boundaries within England, in particular the B7 Upper North-North Boundary (which includes zone Z7), the B11 North East and Yorkshire Boundary (which includes zones Z7 and Z8) and the B16 North East, Trent and Yorkshire Boundary (which includes zones Z7, Z8 and Z10), until currently planned reinforcements are developed. These boundaries are currently non-compliant for the SYS background. Furthermore, the probabilistic assessment in the previous chapter indicates a rather high likelihood of insufficient capacity for the B8 North-Midlands Boundary (which includes zones Z7, Z8 and Z9).

These circumstances could lead to significant operational constraints and, depending on location, connection dates may be subject to delays until major system reinforcements are completed. The system reinforcements concerned are mainly within Scotland, around the SPT-NGET boundary and in the North East of England. A number of strategic reinforcements are being developed in anticipation of increases in northern generation capacity which will increase the northern transmission capability. On this basis some opportunities may become available for new applicants to connect generation to the north towards the latter part of the seven year period covered by this Statement. The proposed new transmission access rules (see below) are also expected to help provide an opportunity for earlier transmission access for new generation projects.

It is worth stressing that the deterministic rules within the SQSS and the SYS background have been used as the basis of the studies for determining the transmission capacity required to accommodate the current generation ‘contracted’ position and for determining when further generation can be accommodated onto the national electricity transmission system. However, in view of the level of uncertainty associated with the future outturn, it would be misleading and inappropriate to attempt to provide precise numerical guidance with regard to opportunities. More usefully, we are able to provide an overview based on the information presented in other chapters of this Statement; in particular the boundary transfers, Figure 8.B1, Figure 8.B2, Figure 8.B3, Figure 8.B4, Figure 8.B5, Figure 8.B6, Figure 8.B7, Figure 8.B8, Figure 8.B9, Figure 8.B10, Figure 8.B11, Figure 8.B12, Figure 8.B13, Figure 8.B14, Figure 8.B15, Figure 8.B16 and Figure 8.B17, see Chapter 8 (Transmission System Capability). Additional information on zonal generation opportunities is given in "Zonal Commentary" later in this chapter.

The above guidance is necessarily general and emphasises the need to consider individual prospective generation developments on their merits at the time of application. The zonal commentary section presented later in this chapter considers opportunities under both the ‘SYS background’ and the probabilistic backgrounds.

As mentioned in the introduction to this chapter, notwithstanding the above opportunity messages, we will continue to comply with our licence obligations to make offers and we will endeavour to meet our customers' requirements including those relating to timescales.

Transmission Access Review

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

This review was announced in the Government’s Energy White Paper 2007 and was initiated by Ofgem and the Department for Energy and Climate Change (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 national electricity transmission system is provided through arrangements with National Grid, acting as NETSO, under the Connection and Use of System Code (CUSC). The CUSC sets out the contractual framework for connection to, and use of, the national electricity 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.

Interim Connect & Manage

In May 2009, Ofgem announced its intention to grant derogations from the requirements for the transmission infrastructure to comply with SQSS Planning Standards (mainly Section 4). This relaxation from the industry standards was introduced to facilitate generation projects connecting to the grid by accelerating their grid access dates. This was based on an interim 'connect and manage approach, under which any additional constraint costs incurred by the NETSO are socialised across all users. It should be noted that there will be no relaxation of the Operational Standards (Section 5 of the SQSS).

To date 3.8GW of existing projects have had their connection dates advanced, with an additional 2.4GW of generation projects in the process of advancing their connection dates. In addition, this approach has allowed a further 6.4GW of new applications to be offered earlier connection dates than would have been the case under previous arrangements.

For further information on the status of individual projects, please refer to our publication "Transmission Network Quarterly Connections Update – April 2010", available at:

www.nationalgrid.com/uk/Electricity/GettingConnected/gb_agreements/

Enduring Arrangements

The Department of Energy and Climate Change (DECC) is currently progressing with formalising revised arrangements to the grid access regime. The preferred model would introduce Connect and Manage on an enduring basis. All constraint costs, including those arising from the advanced connection, would be socialised equally among all generators and suppliers on a per-MWh basis as they are at present under the Interim Connect and Manage arrangements.

Under Connect and Manage, new generators will able to access the network and start generating as soon as the enabling works needed to connect them to the network are complete, without having to wait for all wider network reinforcement to be completed. NGET (acting in its role of NETSO) will take any necessary action to manage the resulting constraints on the network.

The second DECC consultation on Improving Grid Access closed on 14th April 2010. The final determination on the enduring arrangements will be announced by DECC in due course.

Strategic Investment

The information contained in this year's SYS reflects the recent work undertaken for the Energy Networks Strategy Group (ENSG) – Our Electricity Network – A Vision for 2020. 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. A small proportion of the strategic reinforcements will be completed within the following seven years but most will complete beyond the seven year period to align with the predicted growth in renewable generation. Development and design of the reinforcements is proceeding however regulatory funding for delivery is still to be agreed.

Zonal Power Losses

It was explained in "Zonal Power Losses" in Chapter 7 that the effectiveness, in system terms of any new generating station is related, in part, to the effect it has on system losses. Clearly, if a new power station were to be located in the north, and this were to displace the operation of southern generation, then the north to south power flows would increase, transmission losses would increase and some of the output of the new station would, in effect, be ‘lost’ to the system. However, if the new power station were to be located in the south and this displaced northern generation, the converse would be true. That is, north to south power flows would decrease, system losses would decrease and the relative net effect would be as if a larger station had been installed.

Table 7.4 illustrates the effectiveness, in terms of optimising (i.e. minimising) overall transmission system losses, of locating additional generation in each of the 17 SYS Study Zones in turn. That table presents the 17 zones in order of effectiveness and thereby provides a useful and reasonably robust indicator of relative merits. The resultant order is consistent with the relative order of generation opportunities, discussed in the previous section, and the relative order of generation TNUoS charges across the system.

For comparison, the main tables from Schedule 1 of our 2010/11 ‘Statement of Use of System Charges’, are available on the “Charging” web pages on the National Grid website:

http://www.nationalgrid.com/uk/Electricity/Charges/chargingstatementsapproval/

However, please note that, whilst similar, the 17 SYS Study Zones used for the purpose of displaying zonal power losses differ from the 20 generation and 14 demand TNUoS tariff zones.

Generators are also subject to local circuit and substation tariffs. Details of these can be found at:

http://www.nationalgrid.com/uk/Electricity/Charges/usefulinfo/

Zonal Commentary

This section complements the previous sections of this chapter by providing additional information on opportunities for new generation capacity presented on the basis of individual zones or groups of zones. The following zonal commentary considers the opportunities for new generation on the probabilistic background as well as the SYS background.

The section "Boundary Commentary" in Chapter 8 describes the wide range of probabilistic transfers across the 17 SYS boundaries over the next seven-year period. The reader is guided to the description of the probabilistic transfers for each boundary shown in Figure 8.B1, Figure 8.B2, Figure 8.B3, Figure 8.B4, Figure 8.B5, Figure 8.B6, Figure 8.B7, Figure 8.B8, Figure 8.B9, Figure 8.B10, Figure 8.B11, Figure 8.B12, Figure 8.B13, Figure 8.B14, Figure 8.B15, Figure 8.B16 and Figure 8.B17 within this section. The adoption of a probabilistic view of future boundary transfer levels recognises the fact that there is uncertainty in the future generation and demand background. Clearly, this has an impact on the likely opportunities for the connection of new generation onto the transmission network. The commentary below seeks to address the opportunities for new generation given this level of uncertainty.

Clearly, generation and demand backgrounds, which increase North to South transfers, tend to precipitate the need for major inter-zonal transmission reinforcement and thereby reduce northern opportunities. Such backgrounds would include further northern planting and/or the export of power to France at times of peak. Conversely backgrounds which reduce north to south transfers tend to increase northern opportunities and/or relax the need for major inter-zonal transmission reinforcement. Such backgrounds would include new generation in the South.

In considering the following zonal commentary it is useful to cross reference Table 7.1, which presents the studied generation, demand and transfer for each zone and the boundary commentary section "Boundary Commentary" in Chapter 8. Please note, however, that Table 7.1 is on the basis of the ‘SYS background’ and that the generation capacities given are the ‘studied’ or contributory capacities (based on Table F.4) rather than installed capacities.

For ease of reference, each zonal commentary includes the relevant extract of Table 7.1, repeated in Table 9.Z1 to Table 9.Z17 for each of the SYS Study Zones. Please refer to Table F.4 for the effect of generation capacity changes in terms of other plant displaced from being contributory under the SYS background. The changes in generation capacity from 2009/10 to 2016/17 inclusive are also summarised for each zone in Table 3.13. For further information, Table 3.7 in Chapter 3 gives details of each new generation project together with its SYS Study Zone.

Zone 1: North West (SHETL)

Table 9.Z1 - SYS Study Zone Z1, North West (SHETL)

Quantity (MW)	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Effective Generation	870	899	887	1131	1453	1444	1388
Demand	479	490	489	483	492	496	494
Planned Transfer	391	409	398	648	961	948	894

The SHETL North West zone encompasses the area to the north and west of Fort Augustus, Beauly (near Inverness) and Keith. This area includes a significant amount of existing hydro generation, new renewable generation and the Foyers pumped storage scheme. Demand in this zone is significantly lower than the installed generation; consequently this zone is normally an exporting zone.

Generation in this zone is increasing at a significant rate due to the high volume of new renewable generation seeking connection in the area. Consequently, opportunities for connection of new generation to an SQSS compliant transmission network are very low in this zone. However, due to the changes in access rules described earlier in the chapter, opportunities to connect generation still exist subject to SHETL securing appropriate derogations from the SQSS Planning Standard.

Zone 2: North (SHETL)

Table 9.Z2 - SYS Study Zone Z2, North (SHETL)

Quantity (MW)	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Effective Generation	1250	1244	1273	1262	1453	1444	1428
Demand	572	564	566	560	571	559	554
Planned Transfer	678	680	707	702	882	885	874

The SHETL North zone comprises the area to the north of Errochty and Tealing, and to the east of a line drawn between Keith and Errochty. This area includes the thermal power station at Peterhead and some new renewable generation. Demand in this zone is significantly lower than the installed generation and with a north to south flow from Zone 1, this zone is normally an exporting zone.

Generation in this zone is increasing gradually due to the connection of new renewable generation in the area. Consequently, opportunities for connection of new generation to an SQSS compliant transmission network are very low in this zone. . However, due to the changes in access rules described earlier in the chapter, opportunities to connect generation still exist subject to SHETL securing appropriate derogations from the SQSS Planning Standard.

Zone 3: Sloy (SHETL)

Table 9.Z3 - SYS Study Zone Z3, Sloy (SHETL)

Quantity (MW)	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Effective Generation	306	305	301	327	323	321	182
Demand	59	51	51	52	52	58	56
Planned Transfer	247	254	250	275	271	263	126

The Sloy zone in the south west of the SHETL system encompasses the flows to the north and south of the Sloy busbar. In comparison to the 132kV infrastructure in the area, this boundary includes a significant amount of existing hydro generation and new renewable generation in Kintyre and Argyll. Demand in the area is centred around Oban and Mull, Lochgilphead and Islay and Campbeltown and Arran. The power flows are normally into this zone from Killin in the north and out of the zone to the south towards Windyhill (near Glasgow).

New renewable generation in Kintyre and Argyll is increasing over time and reinforcement is required both to the B3 boundary and the internal Kintyre/Argyll network. The proposed reinforcement for this area is the installation of two subsea cable links from Crossaig, north of Carradale, to Hunterston in Ayrshire.. Consequently, prior to reinforcement, opportunities for connection of new generation to an SQSS compliant transmission network are very low in this zone. However, due to the changes in access rules described earlier in the chapter, opportunities to connect generation still exist subject to SHETL securing appropriate derogations from the SQSS Planning Standard.

Zone 4: South (SHETL)

Table 9.Z4 - SYS Study Zone Z4, South (SHETL)							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Effective Generation	468	466	460	479	531	527	464
Demand	522	523	522	513	524	517	511
Planned Transfer	-54	-57	-62	-34	7	10	-47

Zone 4 comprises the southern part of the SHETL system excluding the Sloy zone. In view of the system limitations to the south of this zone, opportunities for connection of new generation to an SQSS compliant transmission network are very low in this zone. However, due to the changes in access rules described earlier in the chapter, opportunities to connect generation still exist subject to SHETL securing appropriate derogations from the SQSS Planning Standard.

Zone 5: North (SPT)

Table 9.Z5 - SYS Study Zone Z5, North (SPT)							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Effective Generation	2246	2343	2114	1988	2006	2010	1960
Demand	1222	1221	1209	1235	1250	1262	1236
Planned Transfer	1024	1122	905	753	756	748	724

In view of the system limitations within and to the south of this zone, opportunities for connection of new generation are very low.

Zone 6: South (SPT)

Table 9.Z6 - SYS Study Zone Z6, South (SPT)							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Effective Generation	3898	4211	4603	4583	4653	4419	3930
Demand	2830	2835	2848	2864	3046	3036	3013
Planned Transfer	1068	1376	1755	1719	1607	1383	917

Zone 6 comprises the southern part of the SPT system. In view of the system limitations to the south of this zone, opportunities for connection of new generation to an SQSS compliant transmission network are low in this zone. However, due to the changes in access rules described earlier in the chapter, opportunities to connect generation still exist subject to SPT and NGET securing appropriate derogation from the Transmission Licence.

Zone 7: North & North-East England

Table 9.Z7 - SYS Study Zone Z7, North & North East England (NGET)							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Effective Generation	2919	2997	3099	3456	3785	3841	3919
Demand	2748	2710	2679	2697	2712	2615	2506
Planned Transfer	171	287	420	759	1072	1226	1413

Zone 7 lies south of SPT and contains a significant amount of thermal generators connected to 275KV transmission network on the North East coast. The 275KV network will not support significant new connections without major upgrading to 400KV. The zone contains main transmission circuits carrying through flow from Scotland with a scarcity of 400KV connection substations. Given the high through flows and limited transmission capacity there is little opportunity for further connections.

Zone 8: Yorkshire

Table 9.Z8 - SYS Study Zone Z8, Yorkshire (NGET)							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Effective Generation	11327	10770	10303	10016	9657	9273	8938
Demand	5786	5655	5538	5652	5760	5767	5749
Planned Transfer	5541	5115	4765	4364	3897	3506	3189

The zone includes the large concentration of CCGT generation on Humberside and also a significant share of coal fuelled generation. Contracted renewable and non renewable generation is expected in Zone 8 as from 2011/12 and throughout the SYS period although overall decrease in generation within the boundary is expected up to 2016/17 due to some LCPD closures and generators coming off as a result of being out of merit. Zone 8 however still has a large surplus of generation over demand in addition to providing a path for northern exports towards southern regions.

The reducing concentration of existing generation on Humberside means that there is some opportunity for additional generation in Zone 8. Significant developments would probably require further local reinforcements in order to connect. The opportunity for new generation connection projects within this zone is therefore considered medium.

Zone 9: North West England & North Wales

Table 9.Z9 - SYS Study Zone Z9, North West England & North Wales (NGET)							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Effective Generation	8000	7656	7376	7393	7356	7222	7126
Demand	7219	7258	7314	7258	7195	7182	7136
Planned Transfer	781	398	61	136	161	40	-10

This zone is enclosed by the North East & Yorkshire boundary among others towards the East and the North to Midlands boundary in the South. Currently the generation and demand within the zone is close to equal; nonetheless, the main circuits out of the zone support a general North to South transport of power through the zone.

Since Zone 8 has considerably higher generation than demand, under some fault or outage conditions a spill of power occurs westwards and then south through Zone 9 therefore limiting opportunities in Zone 9. Additional reinforcements expected in 2015/16 on the major circuits within Zone 9 (Harker-Hutton reconductor and West coast HVDC link) increase the flow through the North of the zone but not the export capability through the South. Additional connections within the zone would required further reinforcements to the South. Thus, the opportunity for new generation projects within this zone is considered very low.

Zone 10: Trent

Table 9.Z10 - SYS Study Zone Z10, Trent (NGET)							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Effective Generation	5637	5924	6258	5970	5640	5585	5559
Demand	704	717	731	717	702	693	680
Planned Transfer	4933	5207	5526	5253	4938	4892	4879

This zone is enclosed by the North to Midlands boundary towards the North and the North East, the Trent & Yorkshire boundary towards the South, and has a large surplus of generation. The boundary capability assessment indicated no spare capacity for the North East, Trent & Yorkshire boundary for the earlier years. A combination of new generation and closures towards the end of the SYS period gives rise to uncertainty on the exact reinforcements required in this zone. Opportunities for new generation within Zone 10 generally are Medium.

Zone 11: Midlands

Table 9.Z11 - SYS Study Zone Z11, Midlands (NGET)							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Effective Generation	3397	3685	4002	3785	3541	3490	3457
Demand	6594	6738	6899	6884	6864	6878	6862
Planned Transfer	-3197	-3053	-2897	-3099	-3323	-3389	-3405

Zone 11 covers much of the West Midlands. This zone lies between the critical 'North to Midlands' and 'Midlands to South' boundaries and carries a high level of north to south power transfer. The local transmission system comprises of a 400kV outer ring to which a number of large coal fired generating stations are connected and a local 275kV system which serves the West Midlands conurbation. Some of the existing coal generation is expected to close due to the LCPD.

There are two underlying system characteristics, which dominate development within the West Midlands. First there is a large power transfer through the zone from north to south. Secondly, most of the demand within Zone 11 is supplied from the local 275kV system, which has little generation support. The 275kV system has historically been supported by medium and small coal fired generating plant connected at 275kV and also at 132kV. All of this has now closed and the loss of generation support has resulted in increased power transfers from 400kV into the 275kV system.

Given the high boundary through flows and limited local 275KV transmission capacity, further opportunities within the zone are considered as Medium provided a 400KV connection is used.

Zone 12: Anglia & Bucks

Table 9.Z12 - SYS Study Zone Z12, Anglia & Bucks (NGET)							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Effective Generation	4054	4143	4266	4446	4594	4685	4804
Demand	5628	5551	5489	5484	5475	5479	5458
Planned Transfer	-1574	-1408	-1223	-1038	-882	-793	-654

This zone is enclosed by the Midlands to South, South and South West, London and Thames Estuary boundaries. Traditionally the zone has had a significant deficit of generation and strongly contributes to the transport of power from the North towards the South. New generation is now contracted to connect along the east coast which will help balance the demand and generation within the zone. New generation within this zone would serve to reduce the power flow from the North but could lead to a requirement to reinforce the transmission network across the north of London. The opportunity for new projects within the zone is considered as Medium.

Zone 13: South Wales & Central England

Table 9.Z13 - SYS Study Zone Z13, South Wales & Central England (NGET)							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Effective Generation	6235	6169	6154	5920	5644	5546	5478
Demand	4814	4795	4787	4785	4779	4789	4777
Planned Transfer	1421	1375	1367	1135	865	757	701

This zone contains the main interconnected transmission network in South Wales and a large part of the transmission network in Central England. The zone has a large generation base and modest demand so mostly exports to the East. A substantial amount of new generation is scheduled to connect in the SYS background together with some LCPD closures. Generally, the internal transmission is strong but planned generation connections and local restrictions are likely to apply. Hence, the opportunity for new generation projects within the zone is considered to be Low.

Zone 14: London

Table 9.Z14 - SYS Study Zone Z14, London (NGET)							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Effective Generation	1723	1700	1691	1863	2021	1846	1679
Demand	9824	9902	10005	10089	10165	10252	10294
Planned Transfer	-8101	-8202	-8314	-8226	-8143	-8406	-8615

Zone 14 covers the entire Central London region which is a high demand district. The power flow analysis has shown that zone 14 is heavily reliant on zones 12, 13 and 15 for importing its power needs. Given the lack of local generation to London and the large demand new generation would help reduce overall system power flows by reducing reliance on northern generation.

While there is a significant opportunity for generation in this area; the transmission infrastructure within this zone is such that new generation would necessarily need to be sufficiently well spread (allocated with precise locations), if major transmission reinforcements were to be avoided. If suitable sites could be found; opportunities for new generation in this zone would be very high (up to 3 GW). An appreciation has been taken into account, regarding the associated difficulties with access to the existing transmission infrastructure. However there would be a great benefit to the system if new online generators were connected within the Central London zone.

Zone 15: Thames Estuary

Table 9.Z15 - SYS Study Zone Z15, Thames Estuary (NGET)							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Effective Generation	2497	2457	2438	2316	2178	3217	4281
Demand	2004	2013	2028	2022	2016	2008	1992
Planned Transfer	493	444	410	294	163	1209	2289

This zone is encircled by the Thames Estuary boundary and contains significant generation along the Thames Estuary and the Essex and Kent coasts. From Sellindge there is a HVDC cross-channel link joining to the French RTE system and a new link (BritNed) from the Isle of Grain to the Netherlands. Towards the latter end of the SYS period it is expected to see the replanting of the existing Grain generation and the connection of a combination of renewables, CCGT and clean coal generators. Some of the existing coal generation within the boundary is expected to close or drop out of merit.

Future opportunities for new generation are 'very low' given the above generation already contracted to connect within this zone, and nuclear generation connecting beyond the SYS period.

Zone 16: Central South Coast

Table 9.Z16 - SYS Study Zone Z16, Central South Coast (NGET)							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Effective Generation	1239	1056	882	876	863	855	851
Demand	4211	4170	4140	4127	4110	4116	4103
Planned Transfer	-2972	-3115	-3258	-3251	-3247	-3261	-3252

This is an importing zone covering the area from Hastings to Southampton on the South Coast and connected to the adjacent zones by five double circuit 400kV lines. Over the SYS period there is very little change in generation and demand within this zone other than the Oil fuelled generation at Fawley dropping out of merit. The opportunity for new generation development can be regarded as medium, however, reinforcement of the local transmission infrastructure could be required on order for new generation to be accepted.

Zone 17 : South West England

Table 9.Z17 - SYS Study Zone Z17, South West England (NGET)							
Quantity (MW)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Effective Generation	1757	1734	1725	2140	2537	2511	2500
Demand	2605	2567	2535	2529	2522	2528	2524
Planned Transfer	-848	-833	-811	-390	15	-17	-24

This zone is enclosed by the Boundary 13 - South West boundary, and is normally an importing zone with high demand and the only large generation being the nuclear plant at Hinkley Point B and a new CCGT at Langage. New wind generation is expected to be connected within the zone from 2014/15 causing overall local generation coming close to matching the local demand reducing the overall boundary import to close to neutral.

Beyond the seven year period new nuclear generation is contracted to connect at Hinkley Point which will push the zone into exporting power. The future nuclear connection requires new additional circuits to reinforce the existing boundary circuit to provide the required transmission capability.

The opportunity for further generation development can be regarded as ‘low’, given the fact that Z17 is connected to the adjacent zones by a small number of double circuit 400kV lines which are only adequate at the moment due to low boundary transfers. Careful consideration would need to be given for reinforcements should any large development take place at the far western end of the Peninsula.

Voltage Support Services

Introduction

This section provides information on possible future opportunities for the provision of voltage support services to the national electricity transmission system.

Generating units providing a Mandatory Reactive Power Service (i.e. under and in accordance with the requirements of the Grid Code) receive system Ancillary Service Payments according to arrangements set out in Schedule 3 of the Connection and Use of System Code, CUSC. This provides for a Default Payment Mechanism (DPM) and for alternative, bilateral, Market Agreements.

The Schedule also provides for Market Agreements for Enhanced Reactive Power Services from pre-qualified providers (for example, generating units able to provide reactive power capability in excess of the Grid Code requirements).

The terms ‘Reactive Power Default Mechanism’, ‘Obligatory Reactive Power Service’, ‘Enhanced Reactive Power Service’ and ‘Market Agreement’ are defined in Schedule 3 of the CUSC. The CUSC Schedule 3 also sets out payment rules and qualifications and evaluation criteria. The payment rate under the Reactive Power Default Mechanism is now indexed against RPI and Power Prices, and has varied between £2.15/Mvarh and £2.75/Mvarh during 2009/10.

Table 8.2 lists indicative network reinforcements that may be required in future to ensure that the system meets Licence Standards for the given SYS background. Amongst these reinforcements are schemes for the support and control of voltages in different parts of the network. As an alternative to purchasing the relevant assets, we would be willing to contract with service providers for voltage support services when this would be economic. As discussed in "Indicative Reinforcements for Licence Compliance" in Chapter 8 the voltage support schemes detailed in Table 8.2 are those required for the specific 'SYS background'. However, as a general guidance it is broadly true that voltage support requirements increase at high levels of power transfer across the system. Thus further reactive compensation schemes over and above those detailed in Table 8.2 could be expected with backgrounds which result in higher transfer levels.

The voltage support schemes included in Table 8.2 are identified in terms of specific types of plant, i.e. mechanically switched capacitors (MSCs) and static var compensators (SVCs), and in terms of defined ratings at identified supergrid substations. However, these schemes must be regarded as indicative only, and the opportunities will, as previously explained, depend on the outturn generation and demand background. We would consider offers of service in the region of the identified sites, different ratings or different performance characteristics. The offered services would be evaluated on a case by case basis, and contracts awarded where they would be economic and enable system needs to be met by the required dates. The types of voltage support service that might be offered and the types of performance that we would seek are discussed later in this section.

One means by which we address the uncertainty in future transmission requirements, is to delay commitment to asset construction to the latest possible date, while at the same time, ensuring 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 Licence. Similar considerations apply when placing contracts for voltage support services. A contract would be let when we are sufficiently confident that the offer represents an economic, practical and robust means of meeting the system requirements in the context of overall transmission system cost and performance and the surrounding uncertainties. A contract may be valid for one or more years.

The types of services that we believe might be offered include:

(i) generating plant able to offer a greater reactive power range than that specified in the Grid Code and paid for under System Ancillary Service Contracts; and

(ii) synchronous compensation plant, de-clutchable gas turbines or static compensation plant.

However, the above list is illustrative only and any offered service would be considered on its merits.

Contracts would be assessed by comparing the total costs and the performance of alternative options that match the system requirement. Performance factors considered would include rating, speed of response, availability of the service relative to the system requirement and control issues. In the case of additional capability from generating units, the predicted merit order position and running regime of the units would be a critical factor.

Where a contract would involve a new connection to our transmission system (e.g. a service offered under item (ii) above) the cost of the connection would have to be factored into the offered contract price. Before contract terms could be finalised, therefore, a formal application for a connection would need to be submitted in order that we could offer connection terms.

We currently buy equipment of the mechanically switched capacitor (MSC) or static Var compensator (SVC) type specifically for voltage support and these are discussed in the following paragraphs.

Mechanically Switched Capacitors (MSCs)

These provide switchable blocks of susceptance and are used where it is necessary to offset the reactive requirements of the intact system (which change slowly through the day) or to provide a response (after some 30 seconds) following a system contingency such as an outage of transmission equipment or generating unit. MSCs have high year-round availability and reliable performance. They may be operated either by remote control or by automatic control with remote setting of switching criteria.

MSCs would provide the initial basis for contract comparison where the system requirement is to offset slowly varying reactive demands or to provide a slow, infrequent response to system contingencies.

Static Var Compensators (SVCs)

Whilst continuously rated for reactive current within their operating range, these devices are able to adjust their reactive current very quickly (within 100ms) in response to system voltage changes. They are thus used when it is necessary to cope with minute-to-minute changes in reactive requirement, and also rapid changes due, for example, to faults on the system. SVCs have high year-round availability and perform reliably. They operate under automatic control with remote adjustment of control parameters by ourselves.

SVCs would provide the initial basis for contract comparison where the system requirement is to cope with minute-to-minute changes in reactive requirement or to respond rapidly to system contingencies.

All reactive compensation equipment bought by ourselves is specified to be re-locatable to permit redeployment if system needs change in future. Any contract for a reactive service would need to reflect this flexibility through contract duration or re-locatability.

We would welcome offers of voltage support services, subject to provisos that any new equipment connected to the transmission system, including the connection between the equipment and the transmission system, would need to meet (and any existing equipment would need to continue to meet) the relevant commercial and technical standards.

Interested parties considering offering a service are invited to contact the Contracts & Trading Manager, Network Operations, who will provide details of the reactive power market mechanisms and will be happy to discuss possible tenders and contract arrangements, service requirements, locations and performance factors in further detail.

Reactive Energy

Table 9.1 shows the reactive energy generated by Large Power Stations. This has formed the basis upon which ‘reactive energy’ payments are made. Data is provided for the period from April 2005 to March 2010 and is the latest information available at the time of writing. Data for Scotland has only been available since 1 April 2005. Prior to that time information was restricted to the three geographical areas in England and Wales, namely: North, Midlands and South.

Modified versions of the main system boundaries in England and Wales have been used to define the above three geographical areas (see Figure A.4.4). 'North' is defined as the area north of a boundary, which follows boundary 8 in the west but reverts to boundary 9 east of Ratcliffe on Soar. 'South' is defined as the area south of a boundary which follows boundary 9 in the west but reverts to the section of boundary 14 just south of East Claydon, Sundon and Wymondley and then boundary 15 south of Braintree and north of Rayleigh Main. 'Midlands' is the area bounded by the above two modified boundaries.

Table 9.1 - Reactive Utilisation (metered output) April 2005 to March 2010 (TVArh)											
Start Date	**End Date**	**Scotland Lead**	**Scotland Lag**	**North Lead**	**North Lag**	**Midlands Lead**	**Midlands Lag**	**South Lead**	**South Lag**	**Total Lead**	**Total Lag**
Apr-2005	Mar-2006	2.38	1.19	4.17	7.84	1.59	2.95	3.95	2.51	12.09	14.49
Apr-2006	Mar-2007	1.83	1.52	4.78	7.27	1.31	1.84	3.58	2.05	11.5	12.68
Apr-2007	Mar-2008	2.21	0.84	4.58	6.61	1.28	1.43	3.12	1.82	11.19	10.72
Apr-2008	Mar-2009	2.9	0.86	3.69	4.04	1.19	1.08	2.42	1.4	10.21	7.36
Apr-2009	Mar-2010	3.89	0.56	5.28	3.35	1.39	1.14	3.07	1.32	13.63	6.38

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Chapter 10

Market Overview

Introduction

The Energy Act (2004) received Royal Ascent in July 2004. Under powers granted by this legislation the Secretary of State directed changes to licences and designated changes to codes that together provided for the introduction of the British Electricity Trading and Transmission Arrangements (BETTA), which were subsequently introduced on 1 April 2005 They replaced the previous New Electricity Trading Arrangements (NETA) in England and Wales, and the separate arrangements that existed in Scotland and the British Grid System Agreement (BGSA). This chapter 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.

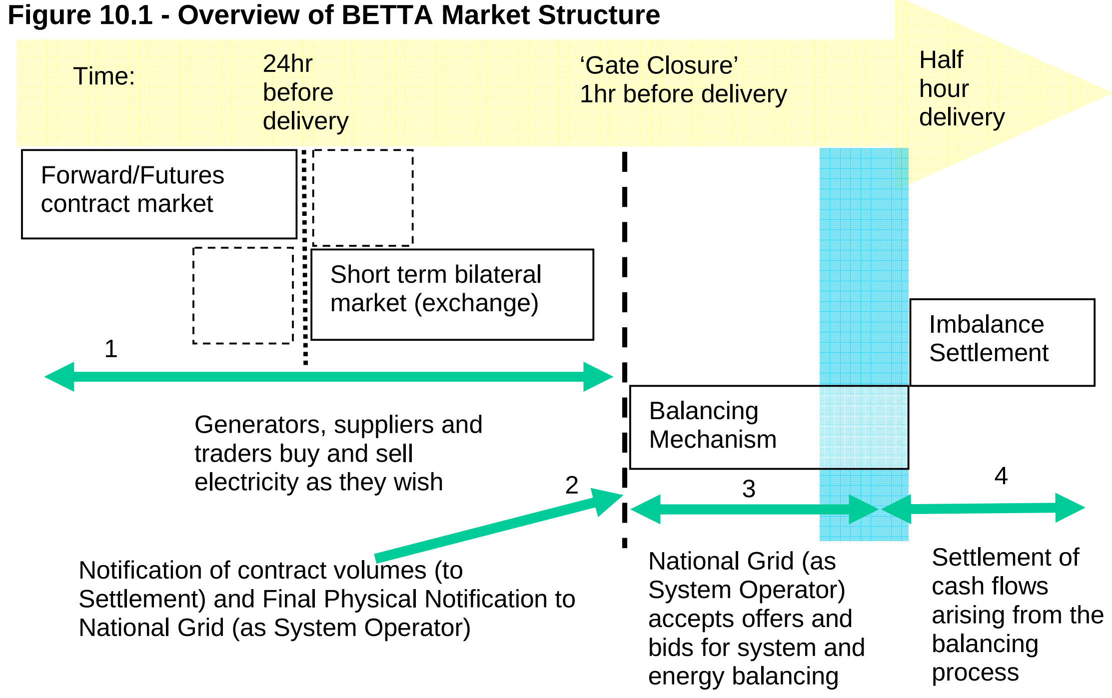
The chapter concludes with a generalised summary of some of the main requirements placed upon users in relation to their obligations to become party to the various codes and charges under BETTA.

British Electricity Trading and Transmission Arrangements

The Market Structure

The arrangements under BETTA are based on bilateral trading between generators, suppliers, traders and customers across a series of markets operating on a rolling half-hourly basis. Under these arrangements generators self despatch their plant rather than being centrally despatched by the System Operator. There are three stages to the new wholesale market, plus a post-event new settlement process. These are illustrated in Figure 10.1.

Figure 10.1 - Overview of BETTA Market Structure



Participation in the bilateral markets (i.e. the Forward/Futures contract market and the Short-term bilateral markets) and the Balancing Mechanism (i.e. offer/bid submission) is optional. Participation in Settlements is mandatory. In addition, certain categories of generator are required to provide Physical Notifications. The Balancing and Settlement Code (BSC) provides the framework within which participants comply with the Balancing Mechanism and Settlement Process. The BSC is administered by a non-profit making entity called Elexon. Information on Elexon is available from its website: www.elexon.co.uk.

The BSC also specifies the process for modifying the BSC itself. All modifications to the BSC are approved by the Authority (Ofgem) and must, in order to be approved, better facilitate achieving the applicable BSC objectives.

Gate Closure is the point in time when market participants notify the System Operator of their intended final physical position and is set at one hour ahead of real time. In addition, no further contract notification can be made to the central settlement systems.

Forwards and Futures Contract Market

The bilateral contracts markets for firm delivery of electricity operate from a year or more ahead of real time (i.e. the actual point in time at which electricity is generated and consumed) and typically up to 24 hours ahead of real time. The markets provide the opportunity for a seller (generator) and buyer (supplier) to enter into contracts to deliver/take delivery, on a specified date, of a given quantity of electricity at an agreed price.

The markets are optional with participants having complete freedom to agree contracts of any form. Formal disclosure of price is not required.

The Forwards and Futures Contract Market is intended to reflect electricity trading over extended periods and represents the majority of trading volumes. Although the market operates typically up to a year ahead of real time, trading is possible up to Gate Closure.

Short-term Bilateral Markets (Power Exchanges)

Power Exchanges operate over similar timescales, although trading tends to be concentrated in the last 24 hours.

The markets are in the form of screen-based exchanges where participants trade a series of standardised blocks of electricity (e.g. the delivery of xMWh over a specified period of the next day). Power Exchanges enable sellers (generators) and buyers (suppliers) to fine-tune their rolling half hour trade contract positions as their own demand and supply forecasts become more accurate as real time is approached. The markets are firm bilateral markets and participation is optional. One or more published reference prices are available to reflect trading in the Power Exchanges.

Balancing Mechanism

The Balancing Mechanism operates from Gate Closure through to real time and is managed by National Grid in its role as National Electricity Transmission System Operator (NETSO). It exists to ensure that supply and demand can be continuously matched or balanced in real time. The mechanism is operated with the System Operator acting as the sole counter party to all transactions.

Participation in the Balancing Mechanism, which is optional, involves submitting ‘offers’ (proposed trades to increase generation or decrease demand) and/or ‘bids’ (proposed trades to decrease generation or increase demand). The mechanism operates on a ‘pay as bid’ basis.

It is shown (under “Balancing Services”) that we purchase offers, bids and other services to match supply and demand, resolve transmission constraints and thereby balance the system. As part of this process we are also required to ensure that the system is run within operational standards and limits (see entry on Licence Standard in References).

Generators and suppliers registered within the Balancing and Settlement Code are bound by the relevant requirements of the Grid Code which includes the arrangements for System Operator to accept Balancing Mechanism bids and offers, for calling off Balancing Services and for dealing with emergencies.

We have a general duty to operate the transmission system in an efficient, economic and co-ordinated manner through the procurement and utilisation of Balancing Services including Balancing Mechanism bids and offers. Our NETSO Incentive Scheme normally covers this duty.

As the market moves towards the Balancing stage, we need to be able to assess the physical position of market participants to ensure security of supply is maintained effectively and efficiently. To this end, all market participants are required to inform us of their planned net physical flows onto and/or from the system. Initial Physical Notifications (IPNs) are submitted at 11.00a.m. at the day ahead stage. These are continually updated until Gate Closure when they become the Final Physical Notifications (FPNs).

Imbalances and Settlements

Power flows are metered in real time to determine the actual quantities of electricity produced and consumed at each location. The magnitude of any imbalance between participants' contractual positions (as notified at Gate Closure) including accepted offers and bids, and the actual physical flow is then determined. Imbalance volumes are settled at one of the dual imbalance prices; System Buy Price (SBP) and System Sell Price (SSP). Following the Authority approval of BSC Modification Proposal P217A, the methodology that is used to set the imbalance prices changed on 5th November 2009. To explain this change, the following paragraphs describe the previous arrangements and then the new arrangements that were introduced on 5th November 2009.

Previous Imbalance Pricing Arrangements

Imbalance prices are derived by taking the average cost of the marginal 500MWh of actions that National Grid has taken to resolve the energy imbalance – excluding those "tagged" actions taken for system balancing reasons. Previously, system balancing reasons were as follows:

- Actions that are so small in volume they could be the result of rounding errors (De
- Minimis tagging);
- Actions taken which have no affect on the energy balancing of the System but lead to an overall financial benefit for the System Operator (Arbitrage tagging);
- Actions taken to correct short term increases or decreases in generation/demand
- (CADL Flagging).

Under these arrangements the "reverse price" i.e. SBP when the system is long and SSP when the system is short, continues to be based upon a forward market price derived from Power Exchange trades.

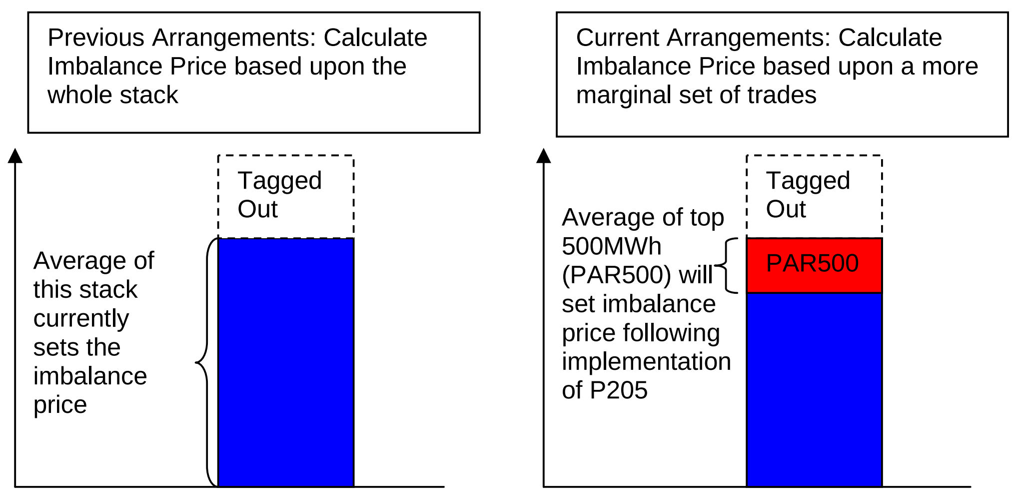
Imbalance Pricing Arrangements from 5th November 2009

From 5th November 2009, we as NETSO 'flag' when we believe a bid-offer acceptance may resolve a transmission constraint. We also flag forward trade actions and certain System Operator to System Operator actions over interconnectors which we believe may resolve a transmission constraint, or which are used to avoid other adverse effects on the systems joined by the interconnection. This flagging is undertaken to enable high priced constraint actions to be removed from the imbalance price calculations.

Flagged actions are assessed against unflagged actions to determine whether they were more expensive than the unflagged actions. If they were, then the price associated with the flagged action is removed. If they weren't, then the flagged action retains its price.

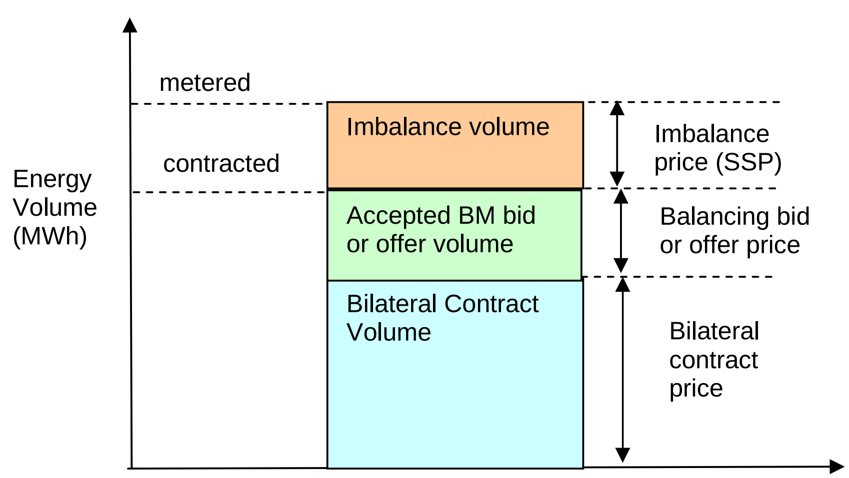
Where prices are removed, a 'replacement price' is calculated from a volume-weighted average of the most expensively priced 100 MWh of priced actions. If there are less than 100 MWh of priced actions, all the priced volume is used to calculate the replacement price.

Figure 10.2 - Imbalance Price Calculation



Imbalance prices are intended to serve as an appropriate incentive for market participants to efficiently manage their contractual energy position ahead of gate closure. There is therefore a link between imbalance prices and plant margin in that the incentive on a participant to balance determines the level and value of contracting in the forward markets. This price signals drives plant availability, and in the longer term should sustain investment in new capacity. It is therefore essential that imbalance prices are set to provide the appropriate incentives in this respect. Figure 10.3 provides a simplified example where the metered energy output of a generator exceeds the contracted position.

Figure 10.3 - Energy Imbalance



There is a positive imbalance volume for which the generator would only be paid at SSP. Under normal circumstances SBP exceeds SSP. Had there been a negative imbalance volume, the system would have bought at SBP to compensate and so the generator would be charged at

SBP. The use of dual imbalance prices is intended to provide an incentive for participants to balance their own position as accurately as possible.

Finally, in addition to energy imbalance charges there is also provision in the market rules for an information imbalance charge. Information imbalance corresponds to the difference between the expected delivery (as indicated by FPNs plus accepted BM bids and offers), on the one hand and metered output/consumption on the other. This charge is currently set at zero.

Balancing Mechanism Reporting Service (BMRS)

As part of the BETTA arrangements, market participants have access to information to enable them to trade to balance their positions and self despatch their plant. The Balancing Mechanism Reporting Service (BMRS) is the service for reporting the necessary information that includes:

- Demand forecasts from National Grid;
- Generation availabilities and margins;
- Imbalance forecasts based on participants' Physical Notifications;
- Submitted BM offer and bid volumes and prices; and
- Accepted BM trades and imbalance prices
- A variety of other information related to market operation

Forecast information is primarily made available for the day ahead and on the day. Submitted BM data is made available shortly after Gate Closure. Accepted bids and offers and initial imbalance prices are published shortly after real time. LogicaCMG operates the systems for this process under contract to Elexon, and administers a dedicated web-site providing near real-time information available at http://www.bmreports.com/.

Market Governance

The Balancing and Settlement Code (BSC)

The BSC sets out the rules governing the operation of the Balancing Mechanism (BM) and the Imbalance Settlement process and also sets out the relationships and responsibilities of all market participants.

All Licence holders (i.e. transmission, generation, supply and distribution) are required to be registered within the BSC. Parties registered within the BSC may or may not choose to participate in the Balancing Mechanism (BM). Participation is defined as submitting an "offer" or a "bid" and is not dependent on its acceptance.

Parties exempt from holding a Licence may nevertheless choose to sign the framework agreement by which the BSC is made contractually binding. They may then also choose to participate in the BM. However, those parties who sign the BSC, whether licensed or licence exempt, are also likely to be required to sign on to the Connection and Use of System Code (CUSC).

A copy of the code may be obtained from www.elexon.co.uk, which also has links to all BSC change process documentation including modifications to the code itself.

The Grid Code (GC)

National Grid has a Licence Obligation in consultation with the other participants, to prepare and at all times to have in force and to implement, comply with, and review regularly, a Grid Code which would set down the operating procedures and principles governing our relationship with all users of the transmission system, be they generating companies, suppliers or suppliers' customers, Externally Interconnected Parties or users with systems directly connected to the transmission system.

The Grid Code is designed to permit the development, maintenance and operation of an efficient, co-ordinated and economical system for the transmission of electricity, to facilitate competition in the generation and supply of electricity and to promote the security and efficiency of the power system as a whole. National Grid and users of the National Electricity Transmission System are required to comply with the Grid Code.

The Grid Code covers all material and technical aspects relating to connections and to the operation and use of the transmission system or, in as far as relevant to the operation and use of the transmission system, the operation of the electric lines and electrical plant connected to it or to a distribution system. It also specifies data which system users are obliged to provide to us for use in the planning and operation of the transmission system, including demand forecasts, availability of generating sets and intended dates of overhaul of large generating sets.

All parties connected to, or involved in the use of, the transmission system, including National Grid, are subject to the Grid Code. Please note that amongst other things, the Grid Code requires that participants embedded within another party's system (e.g. distribution system) must ensure that their physical notifications (see Balancing Mechanism Reporting Service (BMRS)), bids and offers are feasible with respect to their host network. Users' Licences and the Connection and Use of System Code (CUSC) give legal force to the Grid Code. Any changes to the Grid Code are subject to the approval of the Authority (Ofgem).

The Grid Code, along with associated information on its structure is available at http://www.nationalgrid.com/uk/Electricity/Codes/

The Connection and Use of System Code (CUSC)

National Grid is required under the Transmission Licence to be a party to the CUSC Framework Agreement and comply with the CUSC. It is also a requirement for holders of a generation, distribution or supply licence to be a party to the CUSC Framework Agreement and comply with the CUSC. In addition to licensees, the following parties need to be a party to the CUSC Framework Agreement and comply with the CUSC. Users who are:

- Required to sign an agreement pursuant to the Balancing and Settlement Code; or
- Not licensed nor subject to the Balancing and Settlement Code but who are directly connected to the National Grid Transmission System; or
- Who are Embedded and required pursuant to Paragraph 6.5 of the CUSC to have an agreement with National Grid.

The CUSC is a licence-based code setting out within it the principal rights and obligations in relation to connection to and/or use of the national electricity transmission system and also relating to the provision of certain Balancing Services. The CUSC was developed as a replacement to the previous Master Connection and Use of System Agreement (MCUSA), which had been used since Vesting. All persons who were party to the MCUSA as at the CUSC Implementation Date continued as Original Parties to the CUSC Framework Agreement. Other Parties who have since acceded to the CUSC are additional parties.

The CUSC contains obligations for CUSC signatories to comply with the relevant provisions of the Grid Code, and obligations to pay charges in accordance with the Charging Statements.

The SO-TO Code (STC)

The STC is the legal document, which forms the contractual framework for the interactions between the three Transmission Licensees and makes provision for certain interactions between these three parties. These interactions include:

- The Transmission Owners providing Transmission Services to the NETSO;
- Directions from the NETSO to configure the national electricity Transmission System;
- Transmission Outage Planning;
- Joint Transmission Investment Planning;
- Governance of the STC and amendments to it; and
- Dispute resolution.

National Grid's Role and Obligations

Licence Obligations

Section C of the Transmission Licence (System Operator Standard Conditions) places a number of obligations upon National Grid in relation to, amongst other things, the Balancing and Settlement Code (BSC) and these include:

- National Grid shall at all times have in force and comply with, a Balancing and Settlement Code

- National Grid shall operate the transmission system in an efficient, economic and co-ordinated manner; and

- Having taken into account the relevant price and technical differences, National Grid shall not discriminate between any persons or classes of persons in its procurement of Balancing Services.

Under the arrangements of BETTA, NGET, SPT and SHETL each have Transmission Licences that stipulate certain obligations. However, in its role as the NETSO, National Grid has extra responsibilities as indicated above. The SO-TO code (STC) sets out the arrangements for the interface between the NETSO and the Scottish Transmission Operators.
http://www.nationalgrid.com/uk/indinfo/stc/mn_stc.html

Balancing Services

The services that we procure, as NETSO, in order to operate the transmission system constitute Balancing Services.

Balancing Services include:

- Ancillary Services;

- Offers and bids made in the Balancing Mechanism; and

- Other services available to National Grid which serve to assist us in operating the transmission system in accordance with the Electricity Act 1989 or the Conditions in an efficient and economic manner.

Ancillary Services, under the Grid Code, can be Part 1 System Ancillary Services, Part 2 System Ancillary Services or Commercial Ancillary Services. Part 1 System Ancillary Services are those which Users are required to have available in accordance with the Grid Code. Part 2 System Ancillary Services are those optional services (e.g. black start capability) set out in the Grid Code, which the User has agreed to have available. Commercial Ancillary Services are other optional services (e.g. hot standby) described in the Grid Code, which the User has agreed to have available.

Balancing Mechanism offers and bids are commercial services offered by generators and suppliers and procured through arrangements set out in the BSC. They represent the willingness to increase or decrease the energy output from BM Participants in exchange for payment.

Other Services refers to commercial services that can be entered into with any party, which are classified neither as Ancillary Services nor BM offers or bids. These services can be provided by parties who are not authorised electricity operators. This category would include any service provided by parties that are not signatories to the BSC and may also include the procurement of energy ahead of BM timescales.

For further information on Balancing Services, please see the following website:- http://www.nationalgrid.com/uk/indinfo/balancing

Information Provision

There are five documents which we produce pursuant to Condition C16 of the Transmission Licence which have particular relevance in this area, namely the:

- Procurement Guidelines;
- Balancing Principles Statement;
- Balancing Services Adjustment Data (BSAD) Methodology Statement; and
- Applicable Balancing Services Volume Data (ABSVD) Methodology Statement.
- System Management Actions Flagging (SMAF) Methodology Statement

The Procurement Guidelines set out the kinds of Balancing Services which we may be interested in purchasing, together with the mechanisms by which we envisage purchasing such services. The Procurement Guidelines are not prescriptive of every possible situation that we are likely to encounter, but rather represent a generic statement of the procurement principles we expect to follow.

The Balancing Principles Statement defines the broad principles and criteria (the Balancing Principles) by which we determine, at different times and in different circumstances, which Balancing Services we will use to assist in the operation of the transmission system (and/or to assist in doing so efficiently and economically), and when we would resort to measures not involving the use of Balancing Services. The Balancing Principles Statement is designed to indicate the broad framework in which we will make balancing action decisions.

The System Management Actions Flagging (SMAF) Methodology Statement sets out the means which we will use to identify balancing services that are for system management reasons for the purpose of determining Imbalance Price(s).

The Balancing Services Adjustment Data (BSAD) Methodology Statement sets out information on relevant Balancing Services that will be taken into account under the BSC for the purpose of determining Imbalance Price(s).

Further information and electronic versions of the above documents are available from:- http://www.nationalgrid.com/uk/indinfo/balancing

The Offshore Development Information Statement

The Offshore Development Information Statement (ODIS) is produced in accordance with Special Condition C4, and is available at the following location.

https://www.nationalgrid.com/uk/Electricity/ODIS/

The main purpose of the Statement is to facilitate the achievement of the coordinated development of the offshore and onshore electricity grid in Great Britain. The network solutions identified in this report represent a vision of how the offshore and onshore reinforcements could be developed; it is the responsibility of individual onshore/offshore network owner to develop detailed designs. In developing these detailed designs it is envisaged that this Statement will provide guidance in determining the optimum solutions.

Transmission Pricing

Charging Statements

We produce three Charging Statements in accordance with the requirements of the Transmission Licence. Whereas the contractual obligation to pay charges resides within the Connection and Use of System Code (CUSC), the principles that underpin these charges are contained in the Charging Statements.

The three Charging Statements are; the Statement of Use of System Charges; the Statement of Use of System Charging Methodology; and the Statement of the Connection Charging Methodology.

It is a requirement of our Transmission Licence that we charge in accordance with the above Statements. The Statements contain sufficient detail to enable our customers to make a reasonable estimate of their charges. The documents are kept under continual review and any amendments are approved by Ofgem.

In a recent review Ofgem indicated that the governance of charging arrangements should be opened up to Industry participants, currently only National Grid can propose changes. Ofgem recently consulted on the licence changes to facilitate the movement of the charging methodologies into the CUSC. National Grid and the CUSC panel are now developing detailed changes to the CUSC. Following implementation of the governance changes it is expected that users will be able to propose changes to charging arrangements in similar manner to other changes to the CUSC.

For a comprehensive description, please refer to the Charging Statements which are available at the following web site: www.nationalgridinfo.co.uk/charging/index.html.

The follow paragraphs provide a brief summary of National Grid's charges.

Connection Charges

All customers who are directly connected to the national electricity transmission system are subject to Connection charges.

These charges enable National Grid to recover, with a reasonable rate of return, the costs involved in providing the assets that afford connection to the national electricity transmission system. The Connection charges relate to the costs of assets installed solely for and only capable of use by an individual User and take into account the asset value and age. Connection charges additionally include a maintenance component and an overhead component based on the asset value.

Transmission Network Use of System (TNUoS) Charges

Transmission Network Use of System charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) activity function of the Transmission Businesses of each Transmission Licensee. These activities are undertaken to the standards prescribed by the Transmission Licences, to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security.

The basis of charging to recover the allowed revenue is the Investment Cost Related Pricing (ICRP) methodology, which was approved for use for GB in March 2005. Charges are based on the customer's location and on their import and export requirements as calculated by a DC Load flow (DCLF) ICRP transport model. The GB charging methodology was implemented in April 2005.

The TNUoS charge is split in the ratio 27:73 respectively between users that export onto the system (Generators) and users that import from it (Suppliers), and is calculated annually. Where there are significant changes to allowed revenue requirements within year (sum of all revenues that National Grid collects on behalf of all transmission owners) National Grid may revise tariffs accordingly within year. During 2010 / 11 this may occur due to the transition to the Offshore regime. The CUSC requires a two month notice period for a change in Use of System tariffs.

Generation TNUoS Charges

Generators are charged a zonal charge dependent on which tariff zone their power station is connected, together with a specific local charge dependent on the type of connection. There are currently 20 generation TNUoS tariff zones (see Figure A.1.3 and Chapter 6: "Use of System Tariff Zones"). The charges for these zones display a north to south differential and vary from positive tariffs in the north to negative tariffs in some southern zones. This locational message reflects whether the generation contributes to or alleviates the need for additional transmission reinforcement/investment. The basis of the generation charge is the highest Transmission Entry Capacity (TEC) applicable over the year for positive tariff zones, or the average of the three highest metered volumes over the winter period for negative tariff zones. Generators also face a small local charge. The level of this local charge is dependent on whether the connecting substation has redundancy i.e. is single or double busbar, and the type and length of connecting circuits to that substation.

The Transmission Entry Capacity (TEC) of a power station is defined as the access capacity that the generator has requested to export power onto the main transmission system. We use this as input into its planning studies to determine the wider system infrastructure requirements and as the basis for TNUoS charges. TEC is the permitted sum of outputs from the Balancing Mechanism units comprising the power station less station demand, expressed in MW averaged over a Settlement Period.

Demand TNUoS Charges

There are 14 demand TNUoS tariff zones (see Figure A.1.4 and "Use of System Tariff Zones" in Chapter 6), these map to the distribution network operator areas The supplier TNUoS tariffs display a reverse north to south differential relative to the generation tariffs . Whilst there is a minimum level of zero, this is not active due to the greater proportion of revenue that is recoverd from demand (73%) i.e. all tariffs are above zero. Suppliers' charges for half-hourly, metered demand are based on the average of the actual demand supplied during the Triad. The Triad is defined as the three half hour settlement periods of highest transmission system demand during November to February of a Financial Year, separated by 10 clear days. Non half-hourly metered demand charges are on the basis of energy demand over the half hours 16.00 – 19.00 inclusive from 1 April to 31 March.

Balancing Services Use of System (BSUoS) Charges

The Transmission Licence allows us to derive revenue in respect of Balancing Services through the Balancing Services Use of System (BSUoS) charges. We in our role as NETSO, have a responsibility to keep the electricity system in balance (energy balancing) and to maintain quality and security of supply (system balancing). Under the Balancing Services Incentive Scheme we are incentivised on the procurement of services for energy and system balancing and other costs associated with operating the system.

Customers pay for the cost of Balancing Services and any incentivised payments/receipts through BSUoS charges. All users registered within the Balancing and Settlement Code (BSC) are liable to pay BSUoS charges based on their energy taken from or supplied to our transmission system and is calculated every settlement period.

Participants' Requirements

Licence Requirements

Under the provision of the Utilities Act 2000, the Secretary of State's power to grant (and, in the case of supply, extend) electricity licences has been removed. These provisions bring the Electricity Act, 1989 into line with the Gas Act, 1995, where licences may be granted only by the Authority (Ofgem). Accordingly, having determined and published standard conditions to be included in each type of electricity licence, the Secretary of State has no role in the subsequent modification of the standard conditions save only a power to veto modifications proposed by the Authority (Ofgem).

Under the provisions of the Utilities Act 2000, supply and distribution have become separate licensable activities. The previous distinction in legislation between public electricity supplier (PES) and second-tier supply licences have been removed and the supply and distribution businesses of the PES have been put into separate legal entities. There is a bar on the same person holding both an electricity supply and an electricity distribution licence. As a result of this and other changes, the concept of a PES has ceased to exist. However, there is no provision requiring separate supply and distribution companies to be owned separately.

Transmission Licence

Transmission licences are granted under Section 6 (1) (b) of the Electricity Act, 1989. National Grid, SPT and SHETL are currently the holders of the three transmission licences. However, it is possible for further transmission licences to be granted.

Generation Licences

Generation licences are granted pursuant to Section 6 (1) (a) of the Electricity Act, 1989. In essence, any power station capable of providing 100MW or more to the total system in Great Britain is required to have a Generation Licence. In this context the total system means the national electricity transmission system and all distribution systems. Furthermore, a distribution system means a system, which consists (wholly or mainly) of low voltage lines and electrical plant and is used for conveying electricity to any premises or to any other distribution system.

At the time of writing, power stations capable of exporting between 50MW and 100MW to the total system that connected after 30 September 2000 may apply to the Department of Trade and Industry to seek a Licence Exemption (see Chapter 4: "Technical and Data Requirements"). Power Stations that are not capable of exporting 50MW or more to the total system are automatically exempt from the requirement to hold a generation licence.

Supply Licences

Supply Licences are granted pursuant to Section 6 (1) (d) of the Electricity Act, 1989. The concept of geographically mutually exclusive authorised areas, which applied to the previous PES licences does not apply to supply licences. Supply licences may be granted in respect of all customers throughout Great Britain, or may relate to specific geographical areas or customer groups.

As with distribution, some functions necessary to ensure that everyone has reasonable access to electricity, previously carried by the PES in relation to supply, continues and this obligation is imposed through the licences.

Distribution Licences

Distribution licences are granted under Section 6 (1) (c) the Electricity Act, 1989. The concept of geographically mutually exclusive authorised areas for distribution is retained.

Consents Under the Electricity Act 1989

Section 36 Consent (S36)

This refers to Section 36 of the Electricity Act 1989 which specifies that a generating station of over 50MW capacity shall not be constructed, extended or operated except in accordance with a consent granted by the Secretary of State within England and Wales and the Scottish Executive in Scotland. The relevant office takes into account views on particular applications, including views of the local planning authority and, in certain circumstances, may call a public inquiry into a proposal. When granted, consent lasts for five years within which time a project must show signs of construction.

Many of the tables giving information on power stations introduced in Chapter 3 include an indication of whether that plant has obtained S36 and S14 consent or not. For completeness Table 3.2 lists power stations under construction, for which Section 36 and Section 14 consent has been given, and Table 3.3 lists power stations, not yet under construction, for which Section 36 and Section 14 consent has been given. The output capacities (MW) given in the tables are intended to reflect the 'transmission contracted' capacities shown elsewhere in this Statement. The information presented in the tables represents our current view obtained through market intelligence and should not be relied upon; better information may be available through other sources.

Section 14 Consent (S14)

This refers to Section 14 of the Energy Act 1976.

Section 14(1) prohibits the establishment or conversion of an electricity generating station fuelled by oil or natural gas unless notice has been given to the Secretary of State. The Secretary of State may direct, having regard to current energy policies, that the proposal be not carried out or be carried out in accordance with specified conditions.

Section 14(2) makes similar provisions in respect of the making or extension of contracts for obtaining of natural gas to such a station. Stations less than 10MW, and contracts of up to a year's duration, are excepted by Orders under the Act.

Section 14(3) allows the Secretary of State to halt any proposals notified to him, if he considers it expedient, having due regard to current energy policy. This clause may be exercised, for instance, to prevent a project being built which has had Section 36 consent for five years but which, in the opinion of the Secretary of State, has shown no evidence of construction.

Finally, as mentioned in the previous sub-section of this chapter on S36 Consent, Table 3.2 lists power stations under construction for which Section 36 and/or Section 14 consent has been given and Table 3.3 lists power stations not yet under construction for which Section 36 and/or Section 14 consent has been given.

Section 37 Consent (S37)

This refers to Section 37 of the Electricity Act 1989, which specifies that, subject to certain exemptions, an electric line shall not be installed or kept installed above ground except in accordance with a consent granted by the Secretary of State. Exceptions include:

- Electric lines with a nominal voltage of 20kV or less used to supply a single consumer;

- Electric lines within premises in the occupation or control of the person responsible for its installation; or

- Such other cases as may be prescribed.

Compliance with Industry Codes

Table 10.1 at the end of this chapter provides a generalised summary of some of the main requirements placed on generators, suppliers and distributors in relation to their obligations to become party to the various codes and charges discussed earlier in this chapter.

The table is intended only as an initial quick reference guide for readers unfamiliar with the arrangements under BETTA. There may well be variations to the requirements depending on circumstances. The table has been constructed on the basis of the following generalised rules:

- All **directly connected power stations** and directly connected Distribution Systems are required to accede to the **CUSC**.
- All **power stations** (regardless of whether they are directly connected or embedded) capable of exporting 100MW or more to the total system normally require a **Licence**.
- All holders of a **Licence** (regardless of whether they are directly connected or embedded) are required to accede to the **CUSC** and sign the **BSC**
- If **Licence-Exempt**, a User may choose to sign the **BSC** and accede to the **CUSC**;
- If registered within **BSC**, a User may choose to participate in the **BM**;
- **Licence-exempt** embedded generation may nevertheless be required to become party to the **CUSC** or sign an appropriate Bilateral Agreement under the requirements of CUSC Condition 6.5.
- If party to the **CUSC**, a User is bound by and must comply with relevant parts of the **Grid Code**; and
- If party to the **CUSC**, a User has an obligation to pay any relevant charges in accordance with the **Charging Statements**.

Bilateral Agreements

Finally, the section on ”Bilateral Agreements” in Chapter 3 described the three types of Bilateral Agreement, namely: the Bilateral Connection Agreement (BCA); the Bilateral Embedded Generation Agreement (BEGA); and the Bilateral Embedded Licence Exemptable Large Power Station Agreement (BELLA). For completeness, in Chapter 3 under ”Bilateral Agreements”, a fourth type of Bilateral Agreement, namely the Licence Exempt Generation agreement (LEGA), which has now been phased out.

The descriptions contained in Chapter 3 (”Bilateral Agreements”), outline the relationships between the types of agreement, the class of power station, the type of connection to the system, the appropriate terminology for power station output and the appropriate charges. For ease of reference that information has been condensed, tabulated and re-presented here as Table 10.2 at the end of this chapter.

Table 10.1 - Generalised Summary of Main Requirements Placed on Generators, Suppliers and Distributors							
Market Participants	**BSC**	**BM**	**CUSC**	**GC**	**Charges**		
					Connection	**TNUoS**	**BSUoS**
Licence Holders							
Power Stations	yes	optional	yes	yes	if direct	yes	yes
Suppliers	yes	optional	yes	yes	no	yes	yes
Distributors	yes	no	yes	yes	yes	no	no
Licence Exempt							
Large Embedded Power Stations	Yes (subject to CUSC 6.29)	optional if BSC	yes	yes	no	if BSC (subject to CUSC 6.29)	if BSC (subject to CUSC 6.29)
Medium & Small Embedded Power Stations	optional	optional if BSC	if BSC or if required by CUSC Condition 6.5	if CUSC	no	if BSC	if BSC
Transmission Connected Power Stations	Yes (subject to CUSC 6.29)	optional if BSC	yes	yes	yes	if BSC (subject to CUSC 6.29)	if BSC (subject to CUSC 6.29)

Notes for Table 10.1:

1. BSC=Balancing and Settlement Code
2. BM=Balancing Mechanism
3. CUSC=Connection and Use of System Code
4. GC=Grid Code
5. Connection=Connection Charge
6. TNUoS=Transmission Network Use of System Charge
7. BSUoS=Balancing Services Use of System Charge

Table 10.2 - Relationships between Types of Bilateral Agreement, Power Station, Connection, Output Terminology and Charges

Type of Bilateral Agreement	Type of Power Station	Generation Licence	Connection		Power Station Output Terminology			Charges Applicable		
			Embedded	Direct	TEC	CEC	Size of Power Station	Connection	TNUoS	BSUoS
BCA	All	yes		yes	yes	yes		yes	yes	yes
BEGA	All	yes	yes		yes				yes	yes
BELLA	Large	no	yes				yes		if BSC	if BSC

Notes for Table 10.2:

1. BCA=Bilateral Connection Agreement
2. BEGA=Bilateral Embedded Generation Agreement
3. BELLA=Bilateral Embedded Licence Exemptable Large Power Station Agreement
4. A BCA is also for Directly Connected Distribution Systems, Non-Embedded Customer Sites and Interconnector Owners
5. A BEGA is also for Use of System for a Small Power Station Trading Party and a Distribution Interconnector Owner
6. In the case of a BELLA, the relevant Large Power Station must be SMRS registered or CMRS by an appropriate User