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Meeting Scotland's peak demand for electricity

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Introduction

The closure of Longannet in 2016 raised debate about the ability of Scotland to meet its peak demand for electricity. The question was raised that, give Scotland's transmission links to the rest of Great Britain and the interconnection with Northern Ireland, how likely is it that the remaining generation fleet in Scotland can meet peak demand? Looking further ahead, between now and 2030 major changes are expected to the Scottish electricity system: Hunterston and Torness nuclear stations are both expected to close by 2030, there is no certainty over the long term future of Peterhead gas power station, the capacity of wind generation is expected to grow, and the size of the peak demand is also likely to grow. The result is that flows of electricity across the transmission network into and out of Scotland will be considerably more variable, from large exports when it is windy to large imports when it is calm

No single answer to such question can be given with complete certainty. Instead answers should be given in terms of *probabilities*: what is the *probability* that the system can serve Scotland's peak demand? In interpreting the answer, consideration should be given to the tradeoff between the probability of being able to serve peak demand and the costs associated with achieving that level of security. New infrastructure, whether transmission lines or power stations, are expensive both in financial terms and in their impact on people local to them, so the desire for additional capacity must be traded off against the costs of providing it.

Since the late 1930s the electricity system of Scotland has been part of the Great Britain (GB) synchronous system, electrically interconnected through the high voltage transmission network. Throughout the majority of that time dispatch of generation in Scotland was separate to that in England and Wales, with shortfalls or excess being imported or exported over the transmission system from England. In 2005, the Scottish electricity market was combined with the England and Wales market to create the British Electricity Trading and Transmission Arrangements (BETTA) – a set of market arrangement, a shared regulatory system, and a single system operator. It is in this context of a GB-wide electricity system that the question of securing Scotland's peak demand is correctly considered. Scottish generation supports wider GB security of supply at some times, and likewise generation in England and Wales supports Scottish Security of supply. When considering peak demand security, it is impossible to fully separate the interests of Scotland from those of GB.

To understand how secure Scotland's supply of electricity is at peak demand, two coupled questions must be answered questions:

1. Is there sufficient generation in GB to provide security of supply to demand in GB as a whole?

2. Is there sufficient transmission capacity to import any deficit between generation and demand in Scotland? [1]

The first question is often referred to as the 'generation adequacy' question and has in recent years received considerable interest as the system wide generation margin has declined. The second refers to the ability of the transmission system to provide 'interconnection reserve' where generation capacity outside of Scotland can be used through the transmission system to meet Scottish demand.

The transmission network carries out two important roles: it provides interconnection reserve and it facilitates the efficient operation of the market, allowing cheap generation to be used ahead of expensive units without undue limitations due to network constraints. It is the first of these roles that is important in defining Scotland's security of supply.

The transmission system's ability to import power to (or export power from) a region is defined by the *secure transfer capability*. This describes not just the ability of the complete power system to transfer power on a particular day, but its transfer capability under all likely configurations of generators, and its transfer capability 'post-fault' – any one of a range of secured events have occurred. For an initially intact system the list of events which must be secured against include the loss of any one transmission circuit, and the complete loss of one of the two double circuit lines between Scotland and England[2]. A *secure import capability* therefore describes the ability of the power system to transfer power even after a fault, but it does not necessarily give the ability to re-secure the system after such a fault.

The analysis conducted in this report assumes that GB generation adequacy can be met, and therefore Scottish demand can be met either through Scottish generation or, if available, through import from the rest of GB. The key question this report attempts to answer is therefore:

What transmission import capability is required into Scotland in order to provide confidence that peak-demand for electricity can be met?

This report begins by reviewing the GB generation adequacy situation, laying out the standard which is required, the reasoning behind that standard and the mechanisms being used to meet that standard. It then focuses on Scotland with a summary of the current Scottish electricity system and a discussion of likely developments over the coming 15 years. It then presents a probabilistic description of the required transmission interconnection reserve, as defined by the *secure import requirements*, to be met from transmission. Finally it presents a study into the peak demand security of supply for Scotland over the period 2016 to 2030.

[1] The answers to these two questions give an indication on the security of the *bulk* supply of electricity to Scotland as a region of the GB power system. It should be remembered that the vast majority of power cuts are actually due to faults on the distribution network between the transmission network and the end-user. In 2015/16, there were approximate 15 million 'customer interruptions' due to distribution faults in GB, of which 1.5 million were in Scotland: https://www.ofgem.gov.uk/publications-and-updates/electricity-distribution-company-performance-2010-2015.

[2] The SQSS requires that minimum capacity of the transmission grid is planned for the secure event of the outage of a single transmission circuit, a double overhead line on the supergrid (275kV and 400kV) http://www2.nationalgrid.com/uk/industry-information/electricity-codes/sqss/the-sqss/. A double circuit consists of two electrically independent circuits carried on a single set of transmission towers, the four 400kV circuits between England and Scotland are grouped into two double circuits.

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Generation adequacy

The first requirement for meeting the bulk demand for electricity is that sufficient generation capacity is available across the system. In the winter of 2016/17 GB is expected to have 73.7 GW of transmission contracted generation installed and nominally operational[3], down from 74.4GW in 2015/16[4]. Of this total, 14.3 GW is wind in 2016/17 compared with 12.9GW in 2015/16 meaning the conventional generation capacity has dropped from 61.5GW in 2015 to 59.4GW.

The outturn demand peak seen winter in GB depends heavily on weather conditions, with demand showing a strong negative correlation with temperature. On timescales of greater than a week or two, weather conditions are unpredictable and accounting for it in planning the operation of the power system becomes a probabilistic challenge. The outturn of demand and the availability of intermittent generation such as wind can be assigned probabilities rather than being estimated deterministically. The underlying peak demand for electricity is often presented as the Average Cold Spell (ACS) peak demand, which is the value that has a 50% chance of being exceeded across the winter due to the effect of weather. In 2016, the GB ACS peak demand is predicted to be 52.7GW.

At any point during a winter, there is therefore a probability that demand exceeds the generation resource available to meet it. At most times this probability is vanishingly small, but during peak demand periods there is a quantifiable risk that unavailability of generators due to faults combined with the level of wind resource – how windy it is across the country – will lead to a *negative generation margin* and that demand cannot be met from within the normal operation of the electricity market. The trade-off when deciding on the level of generation that should be available across the system is to balance the probability of negative margins against the cost of building new capacity.

Loss of Load Expectation

The reliability / cost trade-off needs a probabilistic analysis in which the probability of negative generation margins is compared with the cost of not serving demand; this requires understanding the value that we place on being supplied and the additional costs (which ends up on consumer's bills) of building new capacity.

The current standard for GB generation adequacy, the enduring reliability standard requires that the Loss of Load Expectation (LoLE) is no more than three hours a year. This means, after carrying out a probabilistic analysis, the expectation (where this term is used in the mathematical sense meaning the long term average) is that available generation exceeds demand for all but three hours in a year. These three hours will most likely occur at peak, or near-peak demand as it is under these conditions that the probability of a negative margin becomes significant. The three hour LoLE standard is derived from two estimated quantities: the Value of Lost Load (VoLL) and the Cost of New Entry (CoNE).

The VoLL estimates the average value consumers place on being supplied. It is challenging to give a meaningful estimate of VOLL as it depends on a wide range of difficult to quantify factors. For example, we may place more value on being supplied during the early evening than the middle of the night, in cold rather than mild weather, and there are differences between VoLL for domestic and industrial consumers, and on the end use of the electrical energy. Work commissioned by the

[3] This includes all generation that is physically connected to the transmission network, plus larger generators connected to the distribution network.

[4] These values are taken from National Grid's Winter Outlook Report 2015 and Winter Outlook Report 2016. The figures include supplementary balancing reserve (full capacity) and exclude interconnection. http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/FES/Winter-Outlook/

UK government in 2013 surveyed domestic and small businesses and estimated an average VoLL of £17,000/ MWh[5], a value that is now used directly in the LoLE calculation.

The CoNE represents an estimate of the annuitized cost of building new generation capacity specifically to service periods of tight margin. It is currently based on the cost per MW of a new Combined Cycle Gas Turbine and is estimated at £47,000/MW[6].

The final LoLE is derived very simply from these two quantities as:

$$LoLE = \frac{CoNE}{VoLL} = \frac{47{,}000}{17{,}000} = 3\ hours\ (to\ 1\ significant\ figure)$$

If, on average, for a particular installed capacity and mix of generation there would be more than three hours a year where demand exceeded available generation, it would be economically sensible to build more generation capacity to reduce the LoLE to the point at which the next MW of generation capacity reduced the LoLE to less than three hours a year. At this point, it becomes economically sensible to simply pay the cost of not serving that demand rather than paying for new generation.

The LoLE standard therefore provides a rational framework for deciding on the level of generation capacity to have on the system. However calculating LoLE required a number of uncertain inputs.

An important input is the probability that each conventional generation unit will be available at any particular time. This is affected by the rate at which a unit is likely to suffer forced outages, and this rate will vary between generators depending on: the technology, age and operating regime. In analysis used today, technology specific availability factors are calculated from historical evidence across all relevant units of a particular type. In GB, this shows for example that pumped storage is highly reliable with historical availability of around 97% during peak demand times in winter, by comparison coal stations show an availability of around 88%[7].

A further level of complexity is introduced by large quantities of wind connected to the system. Wind availability at different locations across Britain is neither fully correlated nor fully independent. It does support generation adequacy in that there is a very high probability that there will be some wind available in Britain at any one time, but it is important that the level of likely wind availability is not over estimated, and the distribution of wind availabilities as a fraction of total installed capacity is realistically modelled.

Interconnectors with other makers provide a further source of electrical energy that can be used to meet peak demand, and in recent year's power flows from mainland Europe have tended to be imports to GB at times of high demand. However, interconnected like generators can suffer outages – for example which removed half the capacity of the 2GW IFA interconnector to France during late autumn 2016. In addition the ability of an interconnector to import to GB rests on their being sufficient generation margin available in the market at the far end, introducing a further layer of uncertainty onto their ability to support GB in future years.

[5] Value given to 2 significant figures: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267613/Annex_C_-_reliability_standard_methodology.pdf
[6] Value given to 2 significant figures: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267613/Annex_C_-_reliability_standard_methodology.pdf
[7] See page 14: https://www.ofgem.gov.uk/sites/default/files/docs/2014/06/electricity_capacity_assessment_2014_-_full_report_final_for_publication.pdf

Table 1: Loss of load expectation and related GB-wide security of supply metrics for the winters 2014/15 to 2016/17[8] (Definitions of terms are given in the Glossary)

	2014/15		2015/16		2016/17	
Contingency Balancing Reserve:	*Excluded*	***Included***	*Excluded*	***Included***	*Excluded*	***Included***
LoLE (hours per year)	1.6	**0.6**	8.9	**1.1**	8.8	**0.5**
De-rated Margin (%)	4.1	**6.1**	1.2	**5.1**	1.1	**6.6**
ACS peak demand (GW)	55.0	**55.0**	54.2	**54.2**	52.7	**52.7**
Operating reserve added to demand (GW)	0.9	**0.9**	0.9	**0.9**	0.9	**0.9**
Assumed net interconnector import (GW)	0	**0**	1.1	**1.1**	2.0	**2.0**
Total installed generation capacity (GW)	71.9	**73.3**	71.9	**75.0**	69.7	**73.7**
of which is wind (GW)	*7.6*	***7.6***	*12.9*	***12.9***	*14.3*	***14.3***
De-rated Capacity (GW)	58.2	**59.3**	54.7	**57.2**	51.5	**55.0**
Wind EFC (%)		**23**		**22**		**21**

Fully modelling all variable is challenging due to both the complexity of the analysis required and the lack of certainty over future system states. Table 1 shows the key generation adequacy security of supply metrics for the years 2014/15 to 2016/17 and a number of the inputs / outputs associated with them. Whilst LoLE represents the best metric with which to compare years, the metric most discussed is the de-rated margin. This is the ACS peak demand minus a form of average generation availability and presented as a percentage, it therefore aims to represent the most likely generation margin at time of system peak demand but is not able to describe the distribution of that margin. Table 1 highlights that ongoing changes in the input assumptions such as assumed interconnector import make the true generation adequacy position difficult to compare across years. Assumptions can change due to real physical changes in system operation, or due to improved analysis and it can be difficult to identify which changes fall into which category.

Although the three hour LoLE standard suggests that there will, on average, be a negative generation margin for this number of hours each year this does not translate into three hours during which customers are disconnected. In most cases, when the generation margin is negative the System Operator is able to deal with the situation without recourse to disconnecting consumers. Figure 1 summarises the tools available for managing periods of negative generation margin. In 2016/17 a Supplementary Balancing Reserve service has been used to supplement generation available in the market to make sure that the system meets the required standard. Therefore the first action that the System Operator will take once no further *market* based generation is available is to trigger this reserve. From the winter of 2017/18 onwards this service will be discontinued and the Capacity Market is expected to procure sufficient capacity to meet the standard, all of which will then operate in the energy market. If all generation capacity has been exhausted, the next stage is to use one of

[8] For further information see: http://www.strath.ac.uk/research/internationalpublicpolicyinstitute/ourblog/november2016/securityofsupplyinthebritishelectricitysystem/

three emergency measures to balance the system without disconnecting consumers. Emergency interconnector instructions can be issued, which in conjunction with the System Operator of neighbouring electricity systems, allow interconnector imports into GB to be increased. A Maximum Generation service allows some generators to be dispatched above their normal 'name plate' capacity for short periods. Finally, the voltage level of the distribution systems can be reduced slightly to lower the instantaneous draw of power without disconnecting consumers. Only after these measures have been taken does the SO need to disconnect customers. In 2014 Ofgem estimated that although the LoLE of that year was likely to be around 0.5 hours per year (so that on average there would be 0.5 hour per year where the generation margin went negative), the probability of needing to disconnect customers was greater than a 1 in 31 year event for all the scenarios they looked at[9].

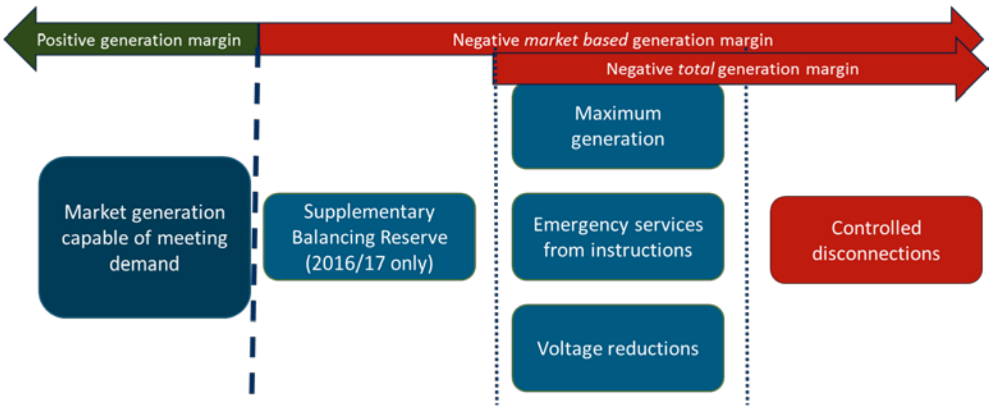

Figure 1: options available to the National Grid as System Operator to balance the system when the generation margin is negative. (Adapted from Ofgem Electricity Capacity Assessment Report 2014)

The LoLE for 2016/17 published in the Winter Outlook report is 0.5 hours per year when including 3.5GW of Supplementary Balancing Reserve held outside the energy and ancillary services markets. From 2017/18 the key mechanism for generation adequacy is the GB capacity market. This creates a centrally administered market for capacity, separate from the market for electrical energy that generators and suppliers currently trade in. For each winter, an assessment is made of the likely level of demand – the ACS peak demand – and the quantity of operational generation capacity needed to meet the three hours per year LoLE standard. Auctions at 4 years ahead and 1 year ahead will be used to procure that capacity, with the auction price allowed (within limits) to rise to the level needed to incentivise generation to be built.

[9] Ofgem, Electricity Capacity Assessment Report: https://www.ofgem.gov.uk/ofgem-publications/88684/electricitycapacityassessment2014-supplementaryappendices.pdf

Transmission interconnection reserve

The standard for defining transmission requirements is contained in the Security and Quality of Supply Standard (SQSS)[10]. Unlike the enduring security standard for generation adequacy, the SQSS sets a deterministic requirement on the secure capability of the transmission network to transfer power across boundaries within the network. In its current form the SQSS makes allowances for building transmission infrastructure to support the dual roles of the transmission network: supporting security of supply (through the provision of 'interconnection reserve'); and facilitating competition in the wholesale electricity market. The changing make-up of the GB electricity system, in particular the increasing penetration of renewable generation and the changing geographical distribution of conventional generators is likely to require a fundamental review of the assumptions underpinning the SQSS, and highlight the need to consider a probabilistic rather than deterministic standard for transmission planning.

In particular, the issue of defining and providing securing of supply to a large region of a power system such as Scotland, is similar to that of providing security of supply to the system as a whole. Once the system-wide generation adequacy standard has been set on a probabilistic basis, a similar method can be applied on a regional scale.

The ability of the transmission network to transfer power between two regions of a power system is not a straight forward case of adding up line capacities. The maximum safe transfer of power depends on the precise operating scenario: where within GB and Scotland demand is located; the maximum current carrying capacity of each component (the 'thermal' rating); the band of acceptable voltages at each location; and a number of technical stability issues. Not only must these be maintained for the intact system (with no components out of service), but the near-instantaneous adjustment of the flow of electricity in event of a fault, means it is also important that the limits are capable of being maintained after credible contingencies have occurred. Table 2 gives a summary of the limits to the transmission system and some comments on how these can be overcome to increase the capability of the network.

When considering the ability of the transmission system to support imports to (or exports from) Scotland, the correct value to quote is the *secure transfer capability*. This is the maximum value that the transmission system as a whole can transfer into or out of a region within all constraints for both an intact system and under all credible contingencies. Contingencies to secure against are defined as secured events in the SQSS and starting from an intact system (that is a system with no maintenance outages, which is the normal case for peak demand periods), the list includes the loss of a single transmission circuit and any double circuit on the 275kV or 400kV[11] network.

The secure transfer capability describes not just the capacity of the intact system, but the post-fault capacity for secured events and for this reason represents a highly reliable description of the transmission system's ability to transfer power. It is this secure transfer capability which is the subject of the existing deterministic SQSS standard.

As security of supply for Scotland is supported by the ability to import power into Scotland, this report considered the question of how much *secure import capability* is needed, and places this question on a probabilistic footing similar to that use for generation adequacy. Specifically, when planning the transmission system to support Scottish security of supply the following question should be answered:

What transmission import capability is required into Scotland in order to provide confidence that peak-demand for electricity can be met?

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[10] (http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/SQSS/The-SQSS/

[11] Other contingencies in the list including, for example the failure of various components in transmission substations.

Table 2: Summary of types of constraint on operation of a power system.

Constraint	Description	Examples of measures to relieve constraint
Thermal rating	The transfer of power through components leads to heating caused by the passage of current. In the case of overhead lines, this heating leads to sag and the ultimate limit is therefore set by the maximum safe height of the conductor above the ground.	• Reconductoring with lower resistance or larger capacity lines. • Build additional circuits. • Change the sharing of power between different circuits in order to more fully exploit the thermal capacity on a set of circuits connecting two areas. (This can be done by equipment such as phase shifting transformers) • Reduce the power transfer across the affected circuits, normally by re-dispatching generation (reducing in the exporting area and increasing in the importing area) or, as a last resort, reducing demand in the importing area.
Voltage levels	Voltages varies across an electricity network, and these variations both drive and are driven by power flows. In order (a) not to overstress network equipment and (b) ensure that network users' equipment works correctly, the voltage magnitude must be kept in the specified band for which equipment connected to the network has been designed.	• Use of reactive power dispatch from generators. • Installation and appropriate control of reactive power compensation (capacitors and inductors). • Changes to the turns ratios of transformers. • In situations of excessively high voltages, switching out of circuits.
Frequency stability	The ability of the system to withstand a mismatch between supply and demand whilst maintaining the frequency close to 50Hz, and to bring the system back into energy balance.	• Contract fast responding frequency responsive headroom (and foot room) and reserve to cover credible short-term variations in generation or demand. • Re-dispatch generation such that the total system inertia is increased. • Re-dispatch generation such that the size of the largest single loss of infeed is reduced.
Angle Stability	A number of constraints related to the possibility that a fault event could lead to individual synchronous generators (of the type used at all power stations except wind and solar farms), or whole regions of a power system to oscillate against the rest of the system and a failure of the system to damp down those oscillations.	• Decrease impedance with neighbouring areas, for example through building additional circuits or installing series compensation. • Improve the control capability in respect of a generator's response to such oscillations. • Reduce the power transfer from the region with excessive generator acceleration.
Voltage Stability	A situation where, even if the voltage magnitude is currently within limits, a particular disturbance can lead to it collapsing to zero and blacking out that part of the system.	• Ensure sufficient reactive power resources (generation or shunt compensation) in place in each region • Ensure appropriate coordination between control systems for devices connected to the network (for example generator and transformers) • Reduce power transfer.
Fault levels	A short circuit on the network leads either to such high currents flowing (high fault level) that protection equipment cannot safely interrupt it, or such low fault currents (low fault level) that it is difficult to distinguish them from currents under normal operation: protection equipment cannot detect it quickly or reliably, and particular designs of HVDC equipment may temporarily cease operation.	*High fault levels:* • Replace switchgear. • Reconfigure the network to ensure lower fault currents. *Low fault levels:* • Install compensation equipment such as synchronous condensers. • Constrain on synchronous generation near the affected location. • Change the operation of HVDC equipment.

When analysing Scottish security of supply, the focus is on the required transmission capability rather than generation capacity due to the nature of the GB regulatory environment. Within GB, the decision on where to locate generation is taken exclusively by the developers of power stations. Their decision will be influenced by a number of factors: the lead-time to gain network access in a particular region; the cost of transmission charges in each area; and resource-based considerations such as proximity to the gas transmission network for gas stations, or the level of wind resource for wind farms. Although these indirect effects will influence where generation locates, there is no direct mechanism by which system planners can influence where generation connects for the specific benefit of the electricity system overall. Instead, for a given geographic spread of generation and demand, the transmission network is developed to serve that distribution to at least the level described in the standards.

It must be also be remembered that in answering this question there is an assumption that generation is available on the far end of the transmission network – that across the whole GB system, generation adequacy has been achieved.

Calculating a probabilistic standard for transmission import requirements

As with the LoLE standard, the requirement for understanding transmission import capabilities in a probabilistic way is to the ability to estimate the distribution of likely import requirements at times of high demand. The shape and spread of the distribution will be defined by three factors: the availability of conventional (schedulable) generation in the region; the outturn demand level; and the level of wind resource[12]. Figure 2 shows an example of such a distribution of import requirements at time of peak demand in Scotland in (a) density and (b) cumulative form. In this example (representing the 2016/17 winter), there is approximately a 40% probability of needing to import into Scotland to meet the annual peak. The level of secure import capability required depends on the confidence level – the greater the level of confidence that peak-demand in Scotland should be met, the larger the secure import capability. Figure 2 indicates four confidence levels: 90%, 99%, 95% and 99.9% and these are reported in more detail in the results section

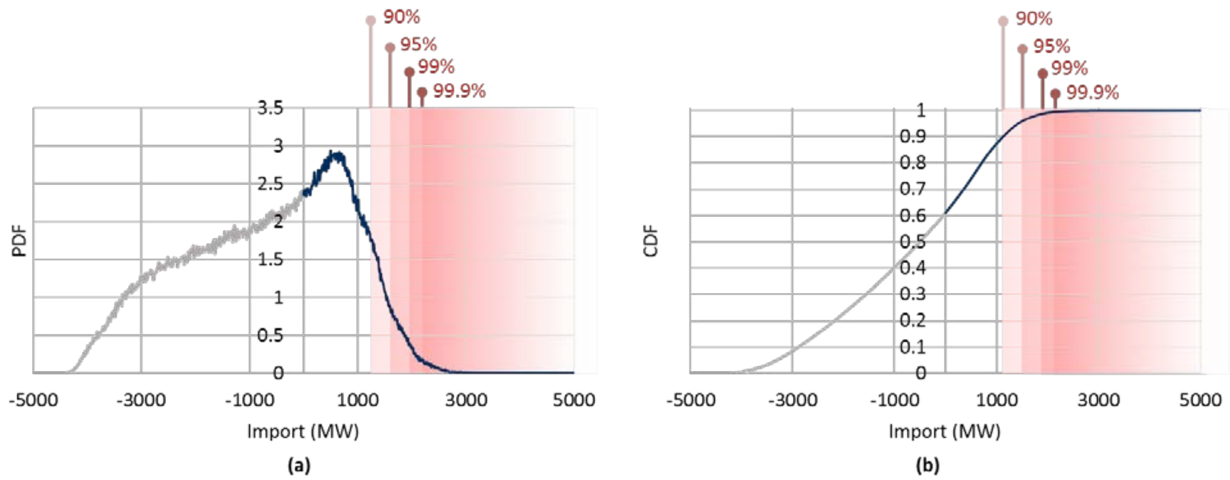

Figure 2: Distribution of import required at time of peak for the 2016 - Base scenario; (a) shows the density function; and (b) shows the cumulative function.

To construct import distributions such as that shown in Figure 2 the underlying distributions for availability at each conventional unit, wind availability across Scotland, and peak-demand outturn are estimated and combined via a convolution. The studies carried out for this report use a Monte Carlo process based on random sampling of each variable's underlying distribution. The following list describes the construction of each distribution:

- **Conventional availability**: Individual conventional unit availabilities are modelled as 'all or nothing' from a Bernoulli distribution with each one sampled separately during each trial. The probability parameter in the Bernoulli distribution is taken from availability factors for particular types of generation (for example coal, CCGT, and nuclear). For hydro unit availability there is an additional step: a hydro-resource correction is included which reduces availability across the hydro

[12] Other intermittent generators such as tidal may influence this calculation in the future. Solar PV generation can be discounted as peak demand in Britain and Scotland occur during early winter weekday evenings.

fleet in line with historic observations that take account of the fact that during dry winters there may be limited water available at certain times.

- **Peak demand outturn:** the distribution of peak demand is modelled as a normal distribution with the mean value set by the ACS peak demand level, and a variance in line with that currently observed across GB.

- **Wind availability:** Modelling wind generation availability is more complex as the availability of wind resource at different locations across Scotland is neither fully correlated nor fully independent. The level of correlation depends on a wide range of factors including the geographical separation and local topological features and this complexity makes the creation of a theoretical model of wind availability virtually impossible. Instead, a common method is to use a long term time-history of wind resource base on meteorological reanalysis. This uses historical atmospheric measurements and remote observations (for example from satellite data) together with techniques similar to those used by weather forecasters to recreate weather quantities such as wind speeds at specific locations. This report uses a nine year history of wind speeds across Scotland as the basis of wind-resource availability[13]. Rather than sampling wind availability separately for each wind farm, an hour is randomly sampled from the winter months of the nine year history. Wind speeds at all locations across Scotland are then taken from that hour and converted to power using a regional power-curve[14]. Finally individual wind farms are mapped to the closest representative location and the profiles for each location are scaled by the associated wind capacity. The process, and the resulting distribution of wind availability for the 2016 Scottish wind fleet are shown in Figure 3.

[13] This data forms part of the Scottish Electricity Dispatch Model (SEDM) dataset and is based on historical reanalysis data from produced by Edinburgh University.

[14] See page 24 of http://www.uwig.org/TradeWind.pdf

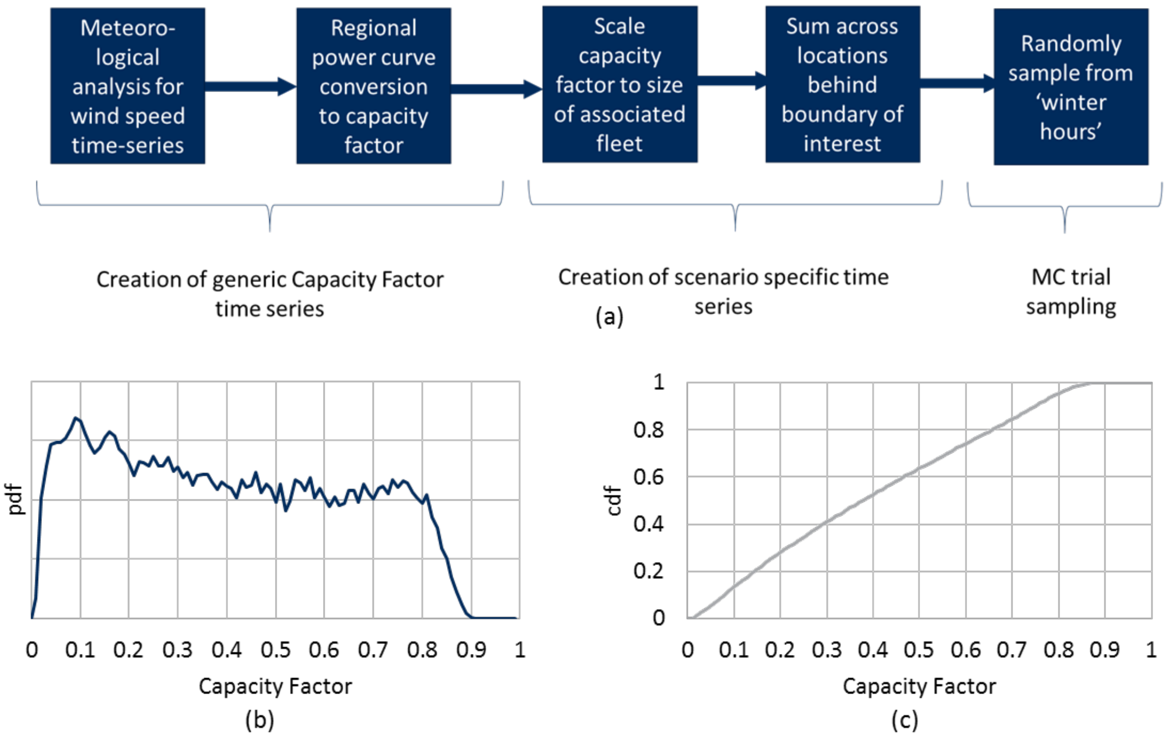

Figure 3: Wind modelling in the Scottish security of supply study: (a) the process of creating wind generation availability's; (b) the probability distribution of the current Scotland-wide wind fleet during winter months; and (c) the same distribution in cumulative form.

The distribution of wind availability, shown in both density and cumulative form, gives an indication of the reliability of Scottish wind for security of supply purposes. Of particular interest in this study is the probability of wind availability close to zero. From the cumulative distribution it is easy to see that there is approximately a 15% probability of the total Scottish wind fleet having an output of less than 10% of installed capacity and there is a 1% probability that availability is less than 2% of installed capacity. Understanding this lower tail of the distribution and how it interacts with the availability of other generators is important.

The Monte Carlo process used to build up an estimate of the import distribution is shown in Figure 4. The studies presented in this report are based on Monte Carlo simulations of 1 million trials. For each trial the fundamental outcome is simply:

$$Import\ required = peak\ demand - available\ generation\ capacity$$

For trials where generation availability is greater than demand, the import required is properly zero. However, the negative domain is kept for clarity[15].

[15] A negative import requirement can therefore be interpreted as the level of *secure export capability* that would be needed to fully utilise Scottish generation availability in interconnection reserve for the rest of GB.

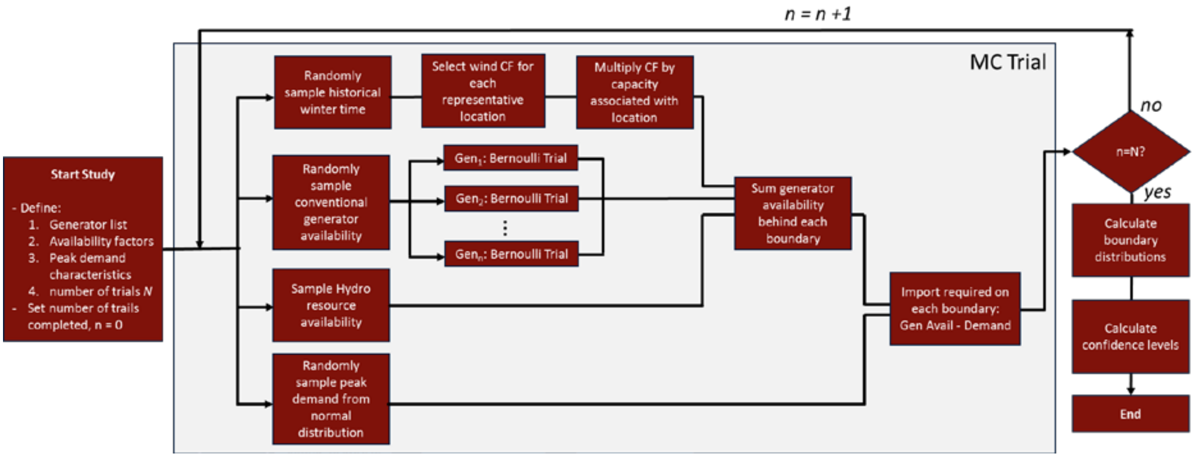

Figure 4: Monte Carlo process for estimating the distribution of import requirements for a scenario.

An important assumption implicit in this model is that of independence between the input variables. Hence, availability at each individual Conventional unit is assumed to be independent of each other and of other factors (with the exception of the hydro resource correction), and overall conventional availability, wind resource and demand outturn are assumed independent. The assumption of independence between wind resource and demand level is a subject where analysis is developing, with National Grid adjusting its methodology for generation adequacy studies in 2016. Sensitivity analysis shows that some level of dependency between these variables has negligible impact on the results and this is discussed further in section 0.

The remaining three sections of this report focus on answering the question of secure import requirements in order to meet Scottish peak demand in scenarios representing likely developments of the Scottish electricity system from 2016 to 2030.

The Scottish electricity system

Historically, Scotland has been a region with a significant surplus of electricity generation capacity over peak demand and has acted as a source of generation availability to support the rest of GB during periods of high demand. This has allowed Scotland to be relatively self-sufficient, only needing to import on a small number of occasions each year. However, recent closure of fossil fuel generation and the expected closure of nuclear stations over the coming 15 years will lead to a need for greater transmission import capability combined with adequacy generation capacity across GB to secure Scotland's own peak demand.

Along with the closure of conventional generators, there is expected to be continued growth in weather dependent renewable generation capacity. Wind generation is expected to continue growing with projections for wind capacity in Scotland of up to 20GW by 2030. Interconnection between GB and other markets is also expected to increase. Of the four existing interconnectors, only the Moyle link is connected in Scotland and at present.

Demand

The demand for electricity from the transmission system in Scotland ranges from around 1GW to just over 5GW, with an absolute peak demand of approximately 5.5GW. Figure 5 shows the demand for electricity in Scotland during 2015 and the daily and seasonal variations can clearly be seen.

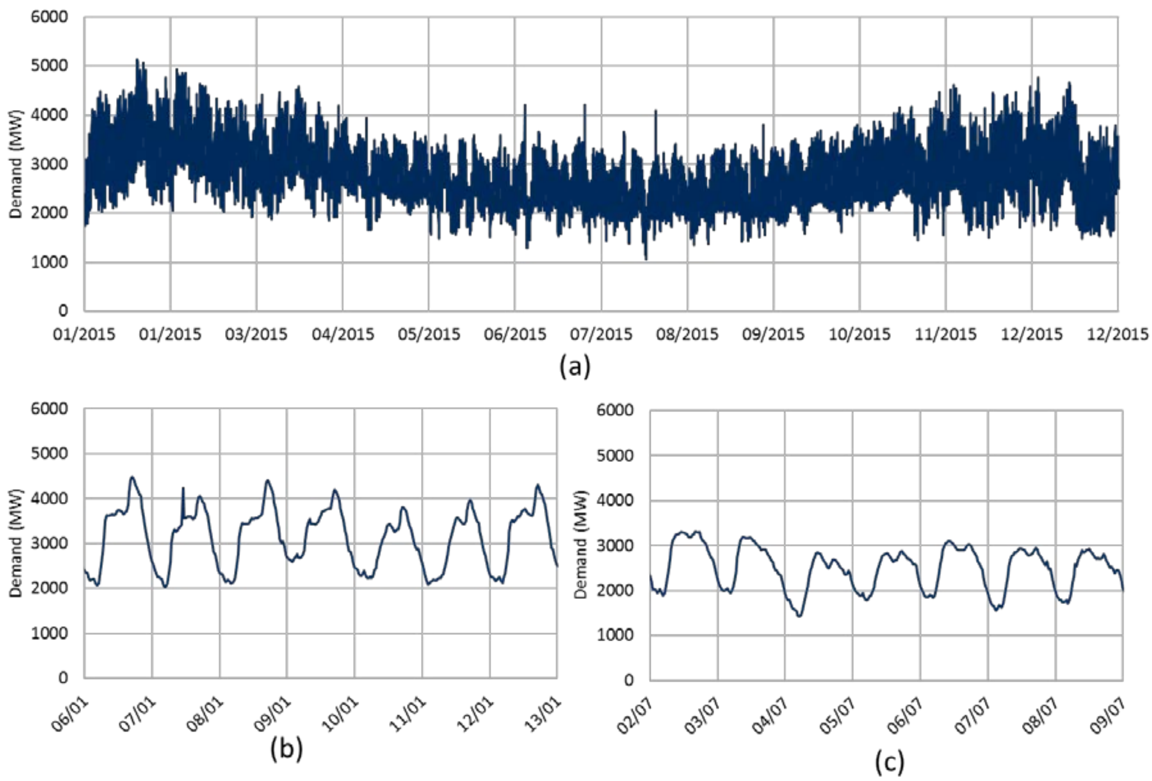

Figure 5: Scottish demand for electricity (a) across 2015; (b) during a typical January week; (c) during a typical July week.

Dispatchable generation

Historically, Scotland has been an area with a significant surplus of generation capacity over peak demand. Major coal, nuclear and gas stations a fleet of dispatchable hydro-electric and pumped-storage stations combined to give a dispatchable generation fleet of approximately 9GW in 2013. By April 2016, Cockenzie and Longannet coal stations had closed, and Peterhead CCGT station had mothballed 780MW of its 1180MW capacity (although the majority of this remained available during the past few winters through a supplementary balancing reserve contract), reducing the conventional capacity in Scotland to 4.7GW. Of this remaining conventional capacity, the nuclear stations at Hunterston and Torness are expected to close by 2023 and 2030 respectively. Whilst there is no indication that Peterhead CCGT station will close in the near future, it is import to consider the implications should it choose to do so[16]. Table 2 lists the major dispatchable power stations in Scotland of 30MW or more as of 2016 (An entry is included for 'other dispatchable hydro' as a number of hydro schemes in north Scotland aggregate the output of smaller stations at different locations within a particular river's catchment area).

Table 3: Dispatchable generation at stations with installed capacity greater than 30MW[17].

Fuel Type	Stations	Region	Capacity (MW)	Number of Units
CCGT	Peterhead	Aberdeenshire	1180	1
Nuclear	Torness	East Lothian	1216	2
	Hunterston	North Ayrshire	947	2
Gas CHP	Grangemouth	West Lothian	145	1
Biomass	Stevens Croft	Dumfries and Galloway	45	1
	Markinch	Fife	50	1
Hydro	Deanie	Highlands	38	1
	Fasnakyle	Highlands	77	3
	Lochay	Highlands	48	1
	Luichart	Highlands	35	1
	Glendoe	Highlands	100	2
	Glenmoriston	Highlands	43	1
	Clachan	Argyle and Bute	40	1
	Sloy	Argyle and Bute	152	4
	Clunie	Perthshire	61	1
	Errochty	Perthshire	75	3
	Rannoch	Perthshire	45	1
	Tummel	Perthshire	34	1
	Tongland	Dumfries and Galloway	33	1
Pumped Store Hydro	Foyers	Highlands	300	2
	Cruachan	Argyle and Bute	440	4
	Other dispatchable hydro		343	
		Total	*5443*	

Wind Generation

Set against this decline in conventional generation capacity is the growth in renewable generation, particularly wind power. The installed capacity of wind has grown significantly over the past decade, with approximately 5.4GW operational as of 2016[18]. This includes 3.3GW[19] under a connection

[16] Much of the conventional plant in GB, including Hunterston, Torness and the hydro and pumped store capacity have won capacity market contracts for delivery in 2018/19 onwards and therefore have an obligation to be available in those years. Peterhead did not win a contract in either of the first two capacity market auctions and therefore does not have a capacity-based obligation to maintain generation capacity.

[17] Data from *Digest of UK Energy Statistics*, Chapter 5 (https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes) and *National Grid Ten Year Statement* (http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Electricity-Ten-Year-Statement/)

[18] http://www.renewableuk.com/page/UKWEDSearch

[19] From the *Transmission Entry Capacity Register*, 16 October 2016 (http://www2.nationalgrid.com/UK/Services/Electricity-connections/Industry-products/TEC-Register/)

agreement with National Grid (generally wind farms of 30MW or greater or newer wind farms of 10MW or greater in northern Scotland) as well as 2.1GW of smaller of wind farms. Figure 6(a) shows the steady growth of installed capacity for the past six years wind in Scotland from January 2010 to September 2016.

The future development of wind in Scotland is difficult to predict, depending as it does on energy prices and a range of policy decisions made at Westminster (macro-energy policies such as subsidies for renewables, and carbon pricing), Holyrood (planning policy, Scottish infrastructure planning) and local authority level (the inclination to grant planning permissions and develop local strategic plans). Whilst a number of UK publications give projections for GB-wide wind capacity in future years, no such study exists for Scotland. One indication of the potential for continued growth of wind is the capacity with planning permission or awaiting planning. Data presented in Figure 6(b) shows that there is 11.8GW of wind capacity in proposed projects. Of this 2.0GW is in construction, 3.9 GW has planning permission and is awaiting construction and 5.9GW is in the planning system[20]. These figures show that there is a likely continuation of the upward trend in installed wind capacity in Scotland over the next few years as projects in construction reach commissioning; medium term there is significant potential for this to continue if the economic, regulatory and political environments are positive.

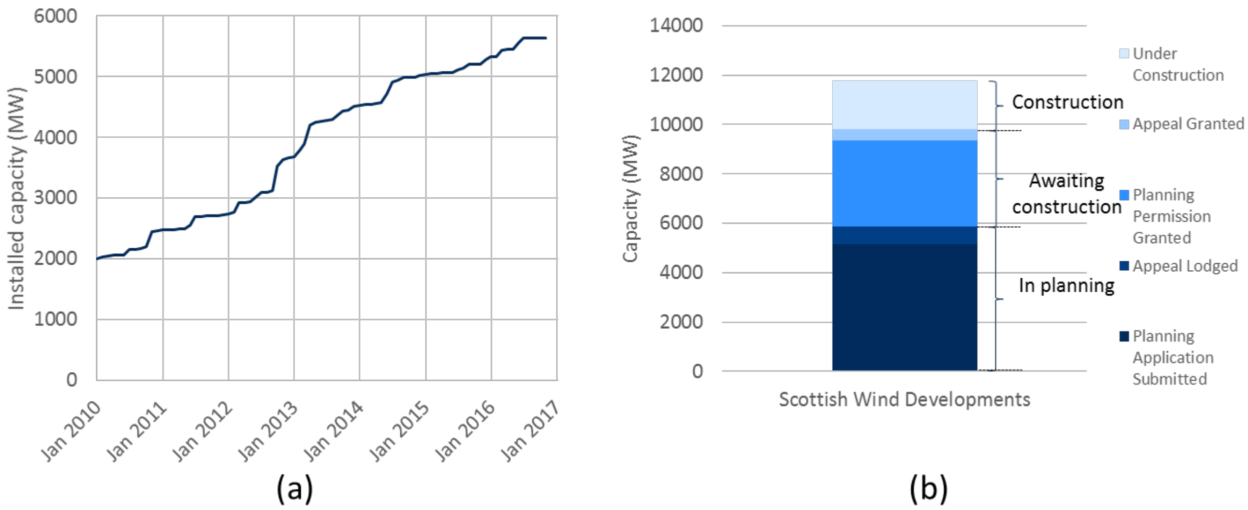

Figure 6: Past and future development of wind capacity in Scotland: (a) cumulative installed wind capacity in Scotland since 2010; and (b) Scottish wind capacity in planning and awaiting construction[21].

Transmission interconnection

Scotland is linked to the wider GB power system through the transmission network. The existing transmission links between Scotland and England are two 400kV double circuits[22] and two much smaller capacity 132kV circuits on the west. Figure 7 shows the major transmission infrastructure in

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[20] Data from the UK Government Renewable Planning Database, October 2016 extract https://www.gov.uk/government/publications/renewable-energy-planning-database-monthly-extract

[21] ibid

[22] A double circuit consists of two electrically independent circuits often carried on the same infrastructure – in the case of overhead lines they are on opposite sides of the transmission towers.

Scotland and linking Scotland to England. The secure transfer capability from Scotland to England is listed by National Grid as 4.4GW [23] and from England to Scotland as 2.65GW[24]. Table 3 gives an overview of the existing transmission system across the border between Scotland and England. It is clear from the table that the secure transfer capabilities are significantly less than the total thermal capacity (the maximum power that can safely be transferred through each individual circuit). This reflects the fact that the secure capabilities include sufficient redundancy to manage the loss of either of the two 400kV double circuits, and the fact that when operating the power system as a whole the system must manage a wide range of constraints (see Table and section 0). The difference between the secure capacity from Scotland to England and England to Scotland is because different constraints are binding on power flows in the two directions.

A major development currently under construction is the HVDC *Western Link* between Hunterston in Scotland and Deeside in north east Wales which is expected to be commissioned in 2017. This will have a thermal rating of 2.2GW and is expected to increase the secure transfer capability of the transmission system from Scotland to England to 6.6 GW[25] and from England to Scotland to 3.9 GW[26]. Discussion with industry suggests that this secure import capability is dependent on the current generation background, and in particular continued operation of Torness and of nuclear and coal generation in the north and midlands of England. Changes to the generation background, and in particular which generation stations remain open will impact on several relevant constraints; closure of some stations may relieve certain constraints, for example freeing up thermal capacity on critical transmission circuits, but may tightening other constraints such as the potential for voltage dips during a fault. Secondly, whilst power flows above 3.5GW can be achieved with the western link, they place greater constraints on other aspects of system operation which may require particular settings on transmission equipment across the wider GB system. For example under some scenarios it may be that the binding constraint on getting power into Scotland will be a limit on a circuit in central England, the reason being that high imports into Scotland depend on being able to move power from southern England into central England and then onto northern England. The result of these two factors suggest that any import into Scotland in excess of 3.5GW may require changes in system operation well away from the border itself, or possibly further upgrades once system conditions change. For

Table 4: Summary of existing transmission circuits between Scotland and England, and the published secure transfer capacity of the system to carry power between the two regions.

From	To	Voltage (kV)	Thermal Capacity (MW)
Eccles	Stella West	400	2770
Eccles	Stella West	400	2770
Gretna	Harker	400	2210
Moffat	Harker	400	2210
Chaplecross	Harker	132	132
Hawick	Harker	132	132
			B6 Secure Transfer Capacity
Scotland	England		4.4 GW *
England	Scotland		2.65 GW

* This assumes completion of a series compensation scheme which will use capacitors to adjust the flow of power across the border and re-conductoring of overhead lines between Torness and Eccles to relieve a thermal constraint. Prior to these projects being completed the Scotland to England secure transfer capability is 3.5GW

23 ETYS, National Grid http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Electricity-Ten-Year-Statement/

24 Security of Electricity Supply in Scotland, National Grid, SP Transmission, SHE Transmission, 2015: http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=40185

25 ETYS, National Grid http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Electricity-Ten-Year-Statement/

26 Security of Electricity Supply in Scotland, National Grid, SP Transmission, SHE Transmission, 2015: http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=40185

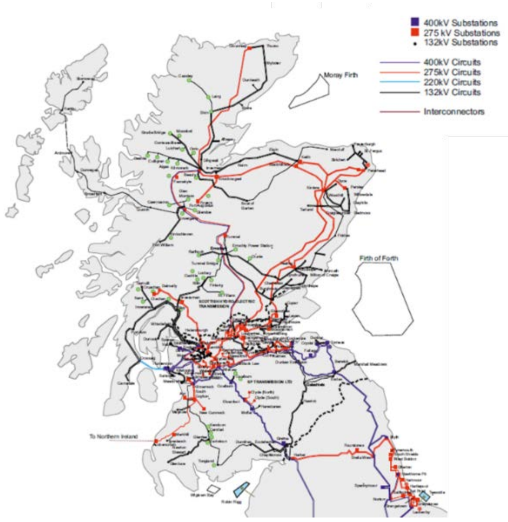


Figure 7: The Transmission network in Scotland[27].

Interconnection with other systems

At present there is one electrical interconnector operating between Scotland and Northern Ireland: the Moyle interconnector. Although Northern Ireland is part of the UK politically, it is part of the Island of Ireland electricity system, which consists of a synchronous power system and electricity market independently to that of the Great Britain.

The Moyle interconnector consists of two independent cables linking Auchencrosh in Dumfries and Galloway with Ballylumford in County Antrim. Each cable has a thermal capacity of 250MW and has individual convertors at the two ends meaning the majority of component faults will only disable half of the capacity. As with the transmission system itself, the thermal rating of the interconnector is only one consideration when defining its ability to import of export. In 2017, the ability of Moyle to import to Scotland is expected to be reduced from 290MW to 80MW due to the limitations of the transmission network in that part of Scotland to import more power; the ability to export will remain at 450MW.

There are a number of new interconnector project proposed which may increase the interconnectivity between Scotland and its neighbouring markets before 2030. Projects are also proposed between Norway and Scotland (NorthConnect[28]) and between Iceland and Scotland (IceLink[29]).

[27] Adapted from Schematics provided in *National Grid's Ten Year Statement* http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Electricity-Ten-Year-Statement/)
[28] North connect project website: http://northconnect.no/
[29] Ice Link project website: http://www2.nationalgrid.com/About-us/European-business-development/Interconnectors/Iceland/

Scottish peak demand security of supply studies

The process of identifying the secure import requirements of the transmission system into Scotland involves calculating level of import capability needed to provide a given confidence of meeting peak demand for the given generation fleet and peak demand levels. The process used is that descried in Section 0 and is applied to scenarios designed to reflect possible developments of the Scottish electricity system from the winter of 2016/17 out to 2030 by using point scenarios for 2016, 2020, 2025 and 2030.

Whilst the secure import requirement represents the main outcome of each study results allow the impact of particular generators and groups of generators to be identified. Of particular interest is the impact that wind generators and interconnectors have on the level of import requirements needed from the transmission network.

Scenarios and sensitivities

Between 2016 and 2030 the main parameters of interest that will vary are the following:

- the conventional units that are operational;
- the capacity of wind capacity operational;
- the ACS peak-demand for Scotland; and
- interconnection with the Island of Ireland and Norway.

Changes in each of these are combined to give scenarios and sensitivities that represent the Scottish electricity systems in each of the spot-years. Table 4 summarises the values used and these are discussed in more detail below. Peak demand and wind penetration levels have been defined based on consultation with industry, and in particular SP Energy Networks who have suggested high and low assumptions for these parameters in the years studied.

Table 5: Summary of scenarios and sensitivities covered with bold used to indicate the base assumption of each parameter

Parameter	Description
Year of Interested	2016 (base), 2020, 2025, 2030
Wind level	For each year (except 2016): High wind penetration; **Low wind penetration**
Demand Level	For each year (except 2016):**High peak demand;** low peak demand
Conventional Stations Open	2016: **All stations open, Peterhead providing 400MW** 2020: **All Stations open, Peterhead providing 400MW;** Peterhead and Hunterston sensitivities 2025: **Hunterston Closed, Peterhead providing 400MW;** Peterhead sensitivities 2030: **Hunterston and Torness Closed, Peterhead providing 400MW;** Peterhead sensitivities
Interconnectors	Baselines studies in each years with **no interconnection** In 2025 and 2030: (1) Full operation of Moyle and Norway interconnection with optimistic market assumptions (2) Moyle interconnector limited to 80MW import.
Conventional availability factors	Baseline studies: use **Ofgem values** Optimistic assumption: use National Grid 2014 Winter Outlook report values Pessimistic assumptions: use values derived from historic balancing mechanism data

Peak demand level

The current level of peak demand in Scotland is approximately 5.5GW and there is expected to be little change over the next five years. Throughout the 2020s the level that peak demand will reach will depend on the level of electrification of heat and transport, economic development, the level of demand flexibility employed, and the penetration of small scale un-monitored distributed generation which is seen by the system as a reduction in the demand level. Figure 8 (a) shows the ASC peak demands assumptions used. For 2020, 2025 and 2030 the default assumption used in sensitivities is the high peak demand assumption.

Wind penetration level

The existing 5.4GW of Scottish wind capacity is expected to continue to grow throughout the period of study. Figure 8 (b) shows the assumptions for installed wind capacities which range from 8GW in the 2020 'low wind' scenario to 18GW in the 2030 'high wind' scenario. The default assumption for each year used in sensitivities is the low wind scenario for that year.

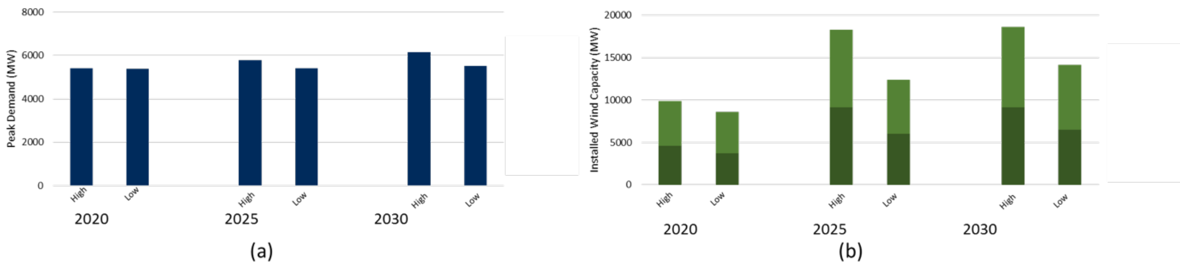


Figure 8: (a) Peak demand levels and (b) installed wind capacity for main scenarios

Conventional generation

The three remaining large power stations in Scotland are Hunterston, Torness and Peterhead. Hunterston is currently expected to close in 2023 and Torness by 2030. Therefore the base-case assumptions are that in 2020 both nuclear stations are open, in 2025 Hunterston is closed and in 2030 Torness and Hunterston are both closed.

Peterhead is currently operating at part capacity with 400MW of its 1180MW operating in the market and a further 750MW used by National Grid as Contingency Reserve. In all the main scenarios Peterhead is assumed to continue providing 400MW. Sensitivities are carried out for 2020, 2025 and 2030 with Peterhead (a) fully closed and (b) fully open.

Interconnectors

Modelling of the impact of interconnectors on security of supply increases the number of factors that need to be considered: the ability of an interconnector to support GB or Scottish security of supply depends not just on its technical availability, but on the availability of both spare generation capacity in the market at the far end of the interconnectors, and a suitable mechanism being in place to direct additional power into GB when required. Modelling this fully would require full European market modelling which is beyond the scope of this report. However, the output of a number of studies used to inform the development of the GB capacity market have been used to give indications of the possible impact of interconnectors.

Interconnection is not included in the majority of studies. Two specific interconnector sensitivities are run for 2025 and 2030 which include both the Moyle and a Norwegian link of 1400MW representing the proposed NorthConnect link. In the 'reduced import' sensitivity Moyle is reduced to a maximum import of 80MW in line with expected changed in the links Transmission Entry Capacity in 2017, in the full interconnection study Moyle operates is modelled as operating at full name-plate capacity.

Conventional unit availabilities

The availability factors determine how likely any one unit is to be available and unavailable. The base values used in the study are those from Ofgem's *Electricity Capacity Assessment 2014*[30]. However, variations in these factors can significantly affect the final results therefore sensitivities are conducted with optimistic and pessimistic set of values. The 'High AF' sensitivity uses values from the National Grid *Winter Outlook Report 2014*[31] which bases values on analysis of peak demand periods over the preceding three winters. The pessimistic set of values is used based on our own analysis of Balancing Mechanism data for the period 2007 – 2015[32]. In particular the pessimistic sensitivity uses an availability factor for nuclear generation significantly lower than that used in the base case (0.71 compared to 0.81).

Table 6: Conventional generation availability factors used in this study.

Generation Type	**Availability Factor** *Low AF sensitivity*	*Base Case*	*High AF sensitivity*
Nuclear	0.71	0.81	0.9
CCGT	0.83	0.87	0.87
Biomass	0.86	0.88	0.9
Hydro	0.83	0.84	0.88
Pumped Store	0.97	0.97	0.98

Confidence levels

The key outcomes of this study is the secure import requirements to provide a given confidence level of meeting peak demand. The exact level of confidence chosen should, from an economic perspective, trade off the cost of upgrading the secure import capability of the transmission network against the value lost by failing to serve peak demand. However, defining a single and universal standard for regional security of supply is problematic due to the differences between each region of the power system. Transmission investment per unit of secure import capability is difficult to estimate, and will vary between regions. It will even vary for different capacity increases for the same region depending on which type of constraint is binding. For example a voltage constraint may be relieved by installing a reactive compensation at a particular location and relatively low cost whereas a thermal constraint may require reconductoring a line with higher capacity cables, or the build of an entire new line at high expense. For this reason, rather than attempting to set a single reliability level, this report provides a range of probabilities of meeting peak demand from 90% to 99.9%, with the main discussion in the report focuses on the 99% confidence level

A secondary output is the ability to identify the impact of any one generator or group of generators on the secure import requirement. This can be found by rerunning the simulations with the generator(s) removed and comparing the two results. It is of particular interest for Scotland to identify the level of security that the Scottish Wind Fleet can supply. This allows, for example, the true impact of wind generation on security of supply to be measured by comparing a study which includes the wind fleet with one that does not.

[30] *Ofgem Capacity Assessment Report 2014*, https://www.ofgem.gov.uk/sites/default/files/docs/2014/06/electricity_capacity_assessment_2014_-_full_report_final_for_publication.pdf

[31] *National Grid Future Energy Scenarios*: http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/FES/Winter-Outlook/

[32] This analysis involved reviewing Maximum Export Limit (MEL) values submitted by generators through the Balancing Mechanism which give the maximum output that a generator unit is capable of providing during any half hour settlement period. A peak-demand availability factor is calculated by averaging MEL values and dividing by installed capacity across settlement periods where demand is within 10% of each year's maximum.

Results: how much secure import does Scotland need to secure peak demand?

Peak demand security of supply in 2016

With the closure of Longannet in early 2016, it is to be expected that there will be a greater need to import into Scotland to cover peak demand. Longannet provided approximately 2,200GW of name-plate capacity across four individual generating units, and in combination with other generators in Scotland this meant that reliance on imports from England and Wales was relatively small. However, analysis of the remaining Scottish generation shows that there is still sufficient import capability in the existing transmission network to provide a high degree of certainty of meeting the Scottish peak demand with the existing generation fleet in the winter of 2016/17.

Table 6 shows the secure import capacities at four confidence levels for the 2016/17 base case and the two *availability factor* sensitivities (The values for the base case corresponding to the distributions shown in Figure 2 on page 10). The table also shows the current published transmission import capability of 2650MW[33]. Under the Base and High Availability Factor assumptions, the current system provides more than a 99.9% probability of securing peak demand.

The impact of varying availability factors shows that the level of secure import capability required at the 99% confidence-level varies by approximately 700MW between the low and high sensitivities, driven strongly by the lower availability of nuclear units in the 'low AF' sensitivity. With low availability factors, the existing transmission network remains sufficient to provide 99% confidence of meeting peak demand under all scenarios.

Table 7: Secure import requirements for 2016 with three assumptions for unit availability factors.

	90%	95%	99%	99.90%	Current Secure Capacity (MW)
2016 - Base	1130	1429	1969	2531	2650
2016 - Low AF	1404	1741	2297	2867	
2016 -High AF	817	1107	1588	2113	

The value of wind

It is often assumed that wind capacity should be ignored in regional security of supply calculations due to the probability of having close to zero wind resource at time of peak demand. This is the assumption currently used in the deterministic SQSS calculation of required transfer capabilities. The studies conducted in this report show that wind generation does have the ability to reduce import requirements. As an entire fleet, it provides an additional sources of generation availability independent of the availability of conventional generators. Significant correlation does exist between wind farms meaning that the contribution of each additional wind farm reduces as the total wind capacity increases.

The 2016 base scenario was repeated with all wind generation removed to allow comparison of secure import requirements with and without wind. Figure 9 shows the effect on the distribution of import requirements at peak demand when wind generation availability is ignored. The change is striking when compared with Figure 2: the lower tail of the distribution is shortened, and the smooth shape is replaced with a multi-modal distribution.

[33] Security of Electricity Supply in Scotland, National Grid, SP Transmission, SHE Transmission, 2015: http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=40185

The key effect from the point of view of security of supply is the change in the upper tail of the distribution as this defines the import capability needed at high confidence levels. Whilst the change is much smaller than for the lower tail, the impact of including wind is to move the upper tail towards lower import requirement.

The multi-modal 'peaked' character of the import distribution without wind is due to the relatively small number of large generation units, five in total (two at Hunterston, two at Torness and one at Peterhead). Significant peaks centred close to 900MW, 1400MW and 2000MW import correspond to full availability of all five units, one major unit unavailable, and two major units unavailable respectively. The resultant distribution is approximately a discrete distribution similar to a binominal with each discrete peak broadened through the effect of both demand variation and the large number of smaller Hydro and Pumped Store units.

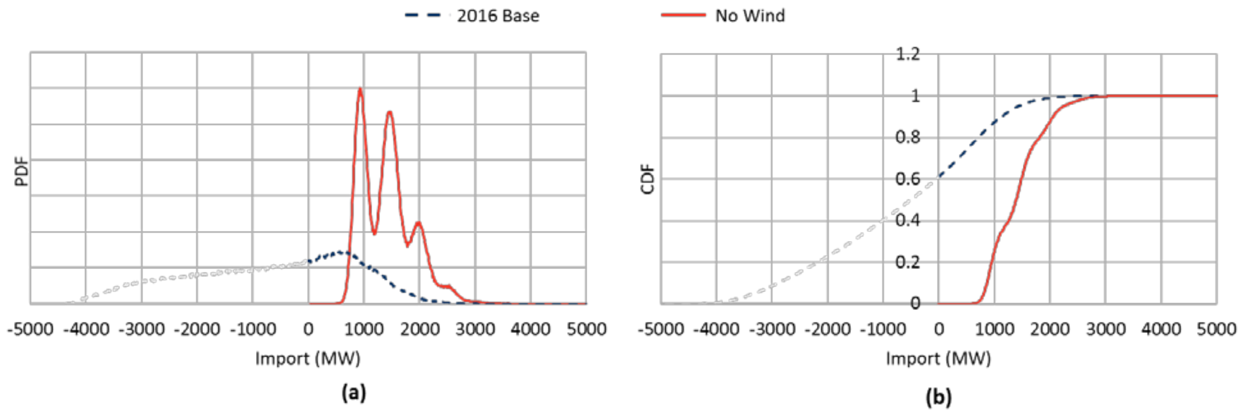


Figure 9: The effect of ignoring the contribution of wind generation to the probability of import levels at periods of peak demand.

The secure import requirements calculated with and without wind are shown in Table 7 together with the calculation of a *regional capacity credit*. This is the reduction in secure import required due to wind as a percentage of the total installed wind capacity. At the 99% confidence level the 5.5 GW of existing wind capacity reduces the transmission import requirement by 700MW. Therefore today's wind fleet can offset 700MW of secure import requirements at this confidence level and leave Scotland with the same probability of meeting our peak demand. This ability to offset secure import capability is analogous to the *effective firm capacity* used in generation adequacy calculations which defines the quantity of fully firm generation capacity that the wind fleet can install.

Table 8: The impact of wind in displacing the need for transmission import requirements.

	90%	**95%**	**99%**	**99.9%**	**Current Secure Capability**
2016 - Base	1130	1429	1969	2531	2650
2016 – No Wind	2057	2247	2669	3140	
Reduction due to wind	*927*	*818*	*700*	*610*	
Regional capacity credit	*16.3%*	*14.4%*	*12.3%*	*10.7%*	

The positive regional capacity credit value shows that wind generation does impact on the level secure import capability required and therefore on Scottish security of supply - adding wind generation does increase security. However, the value of each *additional* unit gives a reduced value in terms of regional capacity credit. Unlike conventional generation where availability is driven by independent fault events, wind generation availability is driven by the weather, which has a significantly level of correlation across Scotland; each new wind farm is not independent of the existing fleet.

The first wind farm connected offered a new and independent source of generation availability to add to the then existing Scottish generation portfolio. The regional capacity credit of this first wind farm was close to its expected capacity factor at times of high demand. The second wind farm, even if geographically separate from the first, will show a high level of correlation between its availability and that of the first farm. The correlation in output between the two farms means that the regional capacity credit of the second farm is slightly less than the first. The rate at which the regional capacity credit reduces depends on the exact geographical spread of the wind fleet and the level of correlation between wind speeds across the region.

Figure 10 shows how the value of the regional capacity credit for Scotland varies as the total installed capacity of wind increases. This is modelled by incrementally adding wind capacity at 500MW blocks to the system starting from zero. The two lines plotted show the average and marginal values; at the current installed capacity of approximately 5.5GW, the average regional capacity credit for the wind fleet is just over 12% (as listed in Table 7) whilst the marginal value – the additional secure import capability displaced by the next 500MW block – is approximately 6%. The impact of increasing wind capacity on the shape of the import distribution is shown in Figure 11. As the installed wind capacity increases, the distribution moves towards lower import requirements, with the greatest effect in the lower tail of the distribution. The movement of the upper tail – which defines the required secure import capabilities – is greatest between the distribution for zero and 1000MW wind capacity, with consecutive lines closer together as the total wind capacity increases.

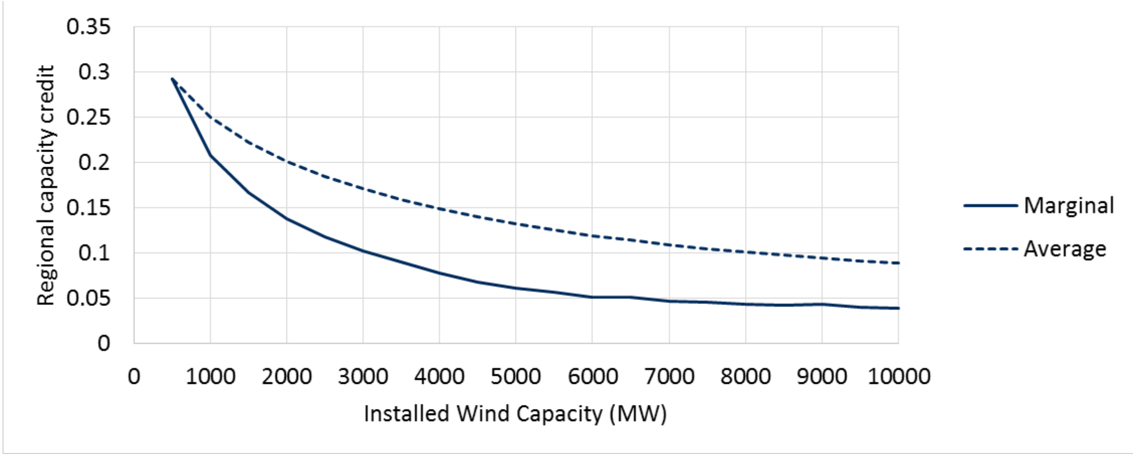


Figure 10: Evolution of the regional capacity credit at the 99% confidence level for wind as the size of the total installed wind capacity increases.

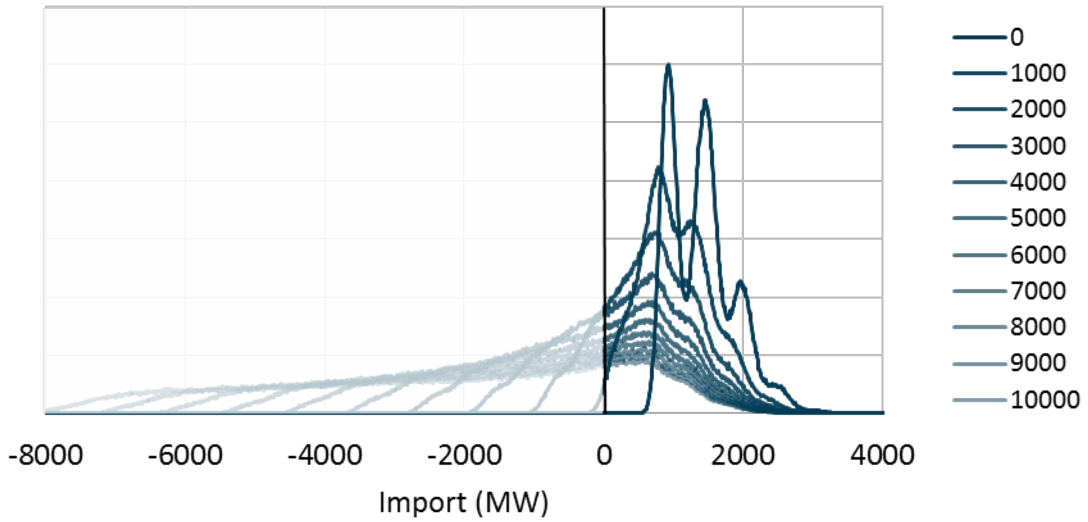


Figure 11: Evolution of the import distribution for the 2016 base case as installed wind capacity increases. Total wind capacity listed in MW.

Peak demand security of supply in 2020

There is not expected to be major changes in the conventional Scottish electricity generation fleet up to 2020 and there is an expectation of continued growth of wind. However, due to the organisation of the GB market, operators of power stations are at liberty to close with little warning. Plants with Capacity Market contracts for delivery of electricity during periods of system stress in the winter of 2018/19 to 2020/21 do provide some confidence that these stations will continue to operate. Both Torness and Hunterston nuclear stations have Capacity Market contracts for their full capacity[34], however Peterhead has not secured a capacity market contract to date.

Table 8 shows secure import requirement for the 2020 base scenario and for availability factor and Peterhead sensitivities. Secure import requirements are seen to reduce between 2016 and 2020. At

[34] Technically these contracts are for ‘de-rated’ capacity –installed capacity multiplied by an availability factor to account for forced outages at individual plants in a method similar to that used in this report.

the 99% confidence level the reduction is from 1969MW to 1743MW and is due to an increase in wind capacity of 2900MW. The additional wind reduced import requirements by 220 MW and therefore has a marginal Regional Capacity Credit of 7.8%.

In addition to the increased generation capacity in Scotland, it is expected that the new 2.2GW HVDC Western Link will be commissioned, initially adding 1,250MW to the secure import capability (see page20 for a more detailed discussion of this value). With the Western Link operational, the 2020 generation fleet and transmission network provide well in excess of 99.9% probability of meeting peak demand in these sensitivities.

Table 9: Secure transmission import requirements for 2020 compared against the existing capability and that expected after the Western Link HVDC scheme is connected

	90%	95%	99%	99.9%	Existing secure capability	With Western Link[a]
2020 - LWHD	740	1128	1743	2349	2650	3900
2020 - LWHD - Low AF	1009	1409	2047	2667		
2020 - LWHD - High AF	484	805	1359	1931		

[a] the value of 3900MW published in the Northern Security Report (2015) will be calculated using system conditions expected to be prevailing around the commissioning of the Western Link HVDC in 2017. As further changes to the power system occur this value is likely to change and may reduce depending on the future spread of generation both within Scotland and across the wider GB system

The impact of early closures at Peterhead and Hunterston in 2020

Unexpected closures of generation in Scotland would require additional imports in 2020. Peterhead is currently providing 400MW in the market, and is capable of providing up to 1180MW if its additional capacity is de-mothballed. At the time of writing Peterhead does not have a Capacity Market contract and therefore has no formal obligation to continue operating out to 2020 – the decision to remain operational will continue to be driven by commercial considerations.

Hunterston power station is expected to continue operating until 2023, however it is conceivable that market conditions could bring that date forward. Unlike Peterhead, Hunterston does have a capacity market contract for 2018/19 through to 2020/21 and therefore is obliged to operate until at least the end of that winter (although in 2016 Fiddlers Ferry, a coal fired power station in norther England threatened to renege on its capacity market contract and forfeit the penalty that entailed. This suggest that even with a Capacity Market contracts there remains uncertainty over whether a station will continue to operate[35]).

To identify the sensitivity of the secure import requirements in 2020 to changes in the operating schedule of Hunterston and Peterhead nine further studies were carried out to show the secure import capabilities under all combinations of future operating situations at: Peterhead (closed, current capacity and full capacity) and Hunterston (current capacity, half capacity and closed). The results at the 99% and 99.9% confidence levels are shown in Table 8. With both stations at full

[35] Fiddlers Ferry press release: http://sse.com/newsandviews/allarticles/2016/02/consultation-on-future-of-sses-fiddlers-ferry-power-station/

capacity the secure import requirement at the 99% confidence level is 1322MW, whilst with both stations closed it is 2712MW; at the 99.9% confidence level the range is from 1710MW to 2813MW. Although these represents a wide range even under the 'worst case' of Peterhead and Hunterston both closing, the requirements remain well within the expected capacity of the transmission system after commissioning of the Western Link.

To put this in context, the peak demand of approximately 5,500MW can be met through a combination of Hydro (1,180MW installed capacity), Torness nuclear station (1230MW installed capacity), pumped storage (750MW), other dispatchable plant (240MW), the transmission secure import capability (up to 3900MW), and any available wind generation. Even taking account of outages and lack of wind resource.

Table 10: Import requirements for combinations of operating capacity at Peterhead and Hunterston in 2020 at (a) the 99% confidence level; and (b) the 99.9% confidence level.

99% confidence		Peterhead		
		Closed	Current	Full
Hunterston	Full	2063	**1743**	1322
	Half	2369	2065	1671
	Closed	2712	2387	2028

(a)

99.9% confidence		Peterhead		
		Closed	Current	Full
Hunterston	full	2228	**1937**	1710
	Half	2520	2230	2047
	Closed	2813	2520	2343

(b)

Peak demand security of supply in 2025 and 2030

Projecting system developments through the 2020s opens the modelling up to a wider range of uncertainties and potential changes to the system. Over this period it is expected that the two Scottish nuclear stations will close, and there is an increased probability that Peterhead will close. Whilst wind generation is expected to continue to increase, the rate of increase depends heavily on the political and economic environment. Similarly the further interconnection of Scotland with its neighbours depends on politics, economics and the development of the systems on either end of the interconnectors.

Table 10 shows the results for base scenarios for 2025 and 2030 with the currently expected closure plan for Hunterston (closed before 2025) and Torness (closed before 2030), together with sensitivities for Peterhead at full capacity and closed. In these studies interconnection is ignored.

In 2025 all scenarios require less 3000MW import at the 99% confidence level and the system should therefore be secured with the existing transmission network and the Western Link. In 2030 the base scenario required

In 2030, the base scenario requires 3682MW of secure import capability for the 99% confidence level. Whilst this is less than the 3900MW value published after commissioning of the western link, this value will represent wider system conditions expected during the second half of the current decade. Closure of generation in northern and central England may make achieving this level without further transmission upgrades difficult (see Section 0 for further discussion). With Peterhead closed by 2030 the secure import capability is above 4000MW and further transmission upgrade would be required assuming no further dispatchable generation located in Scotland.

Table 11: Secure transmission requirements for base scenarios in 2025 and 2030, and results of sensitivities about the availability of Peterhead.

	90%	95%	99%	99.90%	Existing Secure Capacity	With Western Link[a]
2025 (Base assumption: Hunterston closed)					2650	3900
Base	1438	1909	2569	3173		
No Peterhead	1786	2253	2899	3464		
Full Peterhead	756	1250	2127	2983		
2030 (Base assumption: Hunterston and Torness closed)						
Base	2659	3178	3682	4065		
No Peterhead	3009	3528	4054	4445		
Full Peterhead	1975	2505	3114	3744		

[a] the value of 3900MW published in the Norther Security Report (2015) will be calculated using system conditions expected to be prevailing around the commissioning of the western link in 2017. As further changes to the power system occur this value is likely to change and may reduce depending on the future spread of generation both within Scotland and across the wider GB system

The impact of interconnection.

The future impact of interconnectors on security of supply is difficult to estimate as it depends heavily on a number of factors which suffer from high uncertainty. In an efficient system of interconnected markets interconnection should improve security of supply at both ends of the link by allowing each market to share generation reserves. However, poorly designed trading arrangements may fails to direct the flow on the interconnector towards the market that is in greatest need and uncertainties over the future generation margin in both markets make it difficult to identify the level of spare capacity an external market may have to support GB or Scottish security of supply.

For an interconnector to support security of supply three aspects must be in place:

- the interconnector must be technically available to operate;
- there must be spare generation capacity available in the market at the far end of the interconnector; and
- there must be a suitable mechanism to direct the interconnector to import.

The technical availability depends on the technology used and the arrangement of the components in the interconnector to allow redundancy. As an example, the design of the Moyle interconnector allows for the failure of a single major component (convertors or cables) leading to the loss of only half the technical capacity of the link.

The impact of effectiveness of mechanisms in directing the flow – the most common being trading arrangements between markets – was identified in recent work to support the inclusion of interconnectors in the GB capacity market[36]. This highlights the fact that improvements to 'market coupling' in recent years have increased the likelihood of import on the IFA (GB to France) and BritNed (GB to the Netherlands) interconnectors during times of GB system stress. Improvements to market coupling are a key aim of the EUs Energy Union which will drive more efficient mechanisms for both day-ahead and intra-day (less than 24 hours before delivery) scheduling of interconnector flows.

In particular, work by Baringa in 2014 and 2015, and work by Poyry in 2012 have investigated the behaviour of existing interconnectors over the recent past and correlations between market prices in various future projections based on full European electricity market simulations[37].

The analysis presented here makes use of the 'GB importing' scenario from Baringa Redpoint. This is an optimistic scenario in terms of the likelihood of import to Scotland being available at times of GB peak demand from both Ireland and Norway[38]. This scenario suggests that with well-designed trading mechanisms, and one possible mix of generation in the three markets, electricity flows between GB and Ireland would be importing to GB 58% of peak times, and zero flow for 42% of peak times. A link between Norway and GB would import to GB 99% of peak times, and export for 1% of peak times.

Two interconnector sensitivities are included which account for the import capability of the Moyle link. A full capacity sensitivity and a reduced capacity sensitivity with 80MW from 2017 due to constraints on the transmission network internal to southern Scotland.

Table 11 summarises the key physical and market-based inputs that are used in the interconnection sensitivity. The overall physical availability consists of outages of the major components – cables and convertors – and assumptions about the design and ability of each link to operate at half power after certain faults. The total availability of each interconnector is formed by overlaying the physical availability onto the market conditions. Therefore in any one Monte Carlo trial, a market condition is sampled from three states: import to Scotland, no flow, and export from Scotland; then the physical availability of the link is sampled and the two combined.

[36] Historical approaches to estimating interconnection de-rating factors, Poyry
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/404337/Final_historical_derating_of_IC_poyry_report.pdf

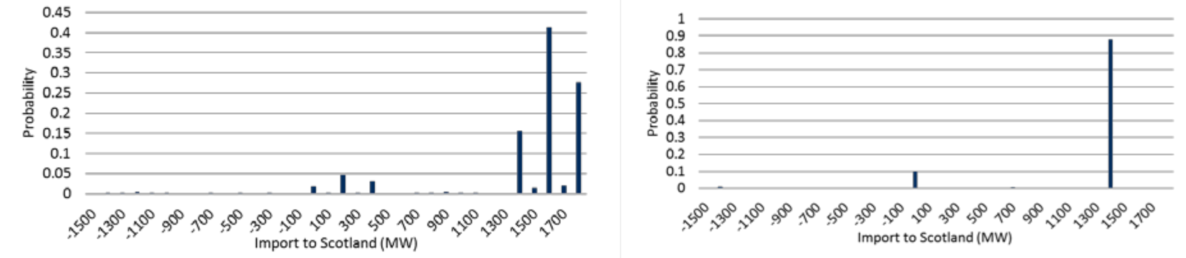
[37] Poyry, 'Analysis of the correlation of stress periods in the electricity markets in GB and its interconnected systems'
https://www.ofgem.gov.uk/ofgem-publications/75231/poyry-analysis-correlation-tight-periods-electricity-markets-gb-and-its-interconnected-systems.pdf
Baringa Redpoint 'Impacts of further electricity interconnection on Great Britain'
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/266307/DECC_Impacts_of_further_electricity_interconnection_for_GB_Redpoint_Report_Final.pdf
Baringa Redpoint ' New electricity interconnection to GB – operation and revenues'
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/322005/new_electricity_interconnection_to_gb_operation_and_revenues_baringa.pdf

[38] The scenario is the 'GB importing scenario' presented in 'New electricity interconnection to GB – operation and revenues' page 18.

Table 12: Technical interconnector capabilities and modelling market interaction.

Physical Characteristics				*Market Characteristic*			
					Probability of…		
Project	*Total Capacity (MW)*	*Overall Availability*	*Scottish Import Limit*	*Market*	*Import to Scotland*	*No Flow*	*Export from Scotland*
Moyle	*450*	*0.982*	*500 Or 80*	*Island of Ireland*	*0.58*	*0.42*	*0*
North Connect	*1400*	*0.940*	*1400*	*Norway*	*0.99*	*0*	*0.01*

Figure 12 shows the distribution of total availability of interconnection into Scotland summed across the Moyle and Norwegian links for (a) full capacity sensetivity; and (b) reduced capacity on Moyle. In both cases, the distribution shows a peak which corresponds to import from Norway, a peak close to zero corresponding to un-availblity of the Norwegian link, and a small probabilty of *negative* capacity (from a Scottish perspective) corresponding to the 1% of cases which require export to Norway.



(a) (b)

Figure 12: Probability distribution of interconnection support for Scottish peak demand with Moyle and North Connect Interconnected included: (a) the distribution with full import capability for Moyle (and (b) shows the results where import on Moyle is limited to 80MW.

Adding interconnection to the 2025 and 2030 base cases using these assumptions leads to a reduction in the secure import requirements as shown in Table 12, however the size of reduction depends on scenario studied and the confidence level required.

At the 99% confidence level, interconnection reduces the secure import required from the transmission network by approximately 1000MW when Moyle is allowed to operate at full capacity, and 800MW if import on Moyle is capped. The reductions compared to the base case for each year are well below the installed capacity of the interconnectors, and highlight the fact that the variation in flows due to both technical and market un-availability reduce the support provided by interconnectors.

Taking a more extreme view of the level of security of supply required, the impact of interconnection at the 99.9% confidence level is significantly lower than at the 99% level. For example in 2030, the addition of interconnection (with Moyle at full capacity) means a total interconnector capacity of 1850MW reduces the secure import requirements by only 242MW. At this high confidence level, the small probability of the Norwegian interconnector dispatching to export from Scotland almost removes the effect of the large probability of it being available for import. This is most clearly seen from the import distribution, the upper part of which is shown in cumulative form in Figure 13.The change in secure import requirements with the addition of the interconnector is shown by the horizontal distance between the two lines. Moving up the graph, the distance between the two lines reduces, and eventually cross (just above a confidence level of 99.9%) showing that there is the potential for this combination of interconnectors to *increase* the need for transmission based secure import capabilities. The narrowing of the gap between the two distributions with and without interconnection at higher confidence levels shows increasing need that these high confidence levels place on mitigating the very small probability of the need to export to Norway coinciding with other events such as low wind, low conventional availability and high peak demand.

Table 13: Secure import requirements for the transmission system with Scottish interconnection included in 2025 and 2030.

	90%	95%	99%	99.90%
2025 (Base assumption: Hunterston closed)				
Base	1438	1909	2569	3173
With Interconnection (full Moyle import)	-90	442	1465	2724
With Interconnection (reduced Moyle import)	139	653	1670	2901
2030 (Base assumption: Hunterston and Torness closed)				
Base	2659	3178	3682	4065
With Interconnection (full Moyle import)	1162	1706	2646	3823
With Interconnection (reduced Moyle import)	1351	1890	2817	3997

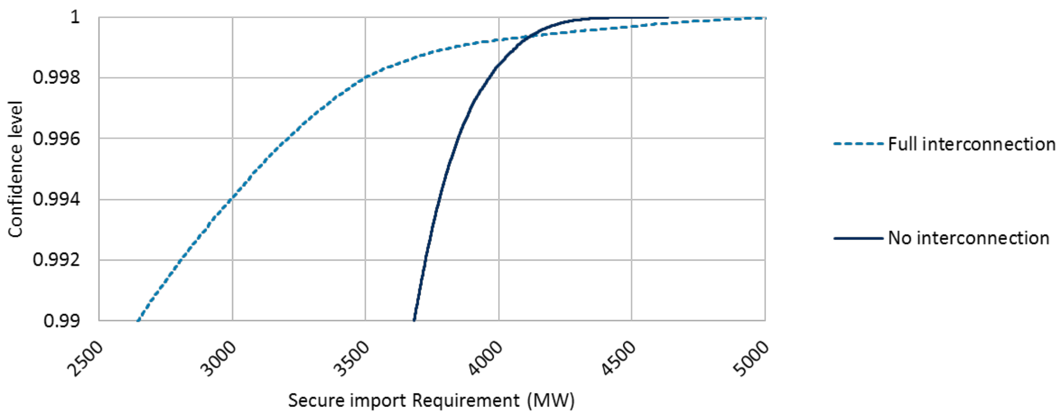


Figure 13: Cumulative distribution of secure import requirements into Scotland from England and Wales for 2030 with and without interconnection with Ireland and Norway.

Discussion: is Scottish peak demand for electricity secure?

This report has laid out a framework under which peak demand security of supply questions for Scotland, as a region of the GB power system, can be analysed. It identifies two driving factors: GB system-wide generation adequacy, and the secure import capability of the transmission network into Scotland.

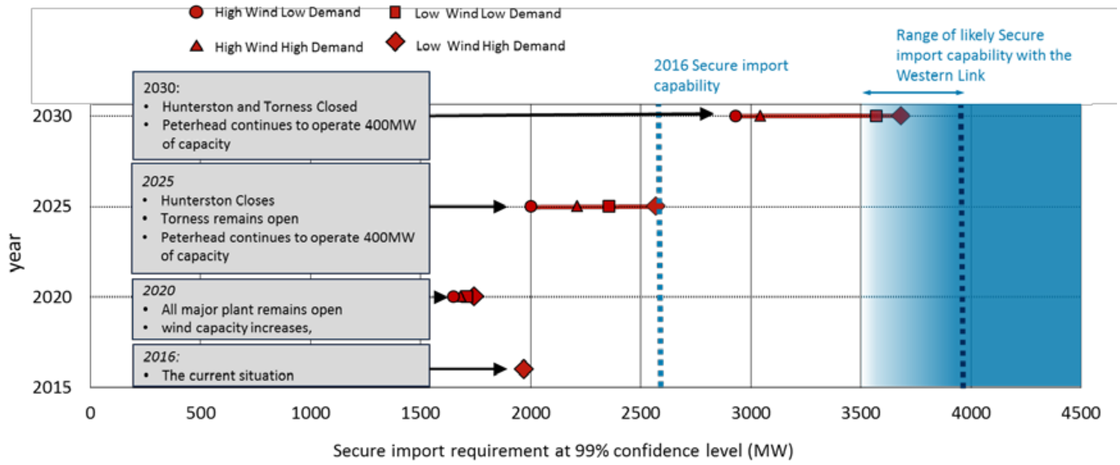
Without sufficient GB generation adequacy, Scottish electricity supply is not secured irrespective of where the generation capacity is in GB; whether in Scotland, England or Wales a lack of generation adequacy in GB leaves Scotland unsecured along with the whole system.

Assuming that GB generation adequacy has been achieved, Scottish peak demand for electricity can be secured via two methods: either a large dispatchable Scottish generation fleet with limited secure import capacity, or a smaller generation fleet in Scotland but increased transmission interconnection with the rest of GB. As the location of generators is at the discretion of commercial developers and operators, the challenge for the system planner is to ensure that the secure import capability matches spread of generation and demand between Scotland and the rest of GB.

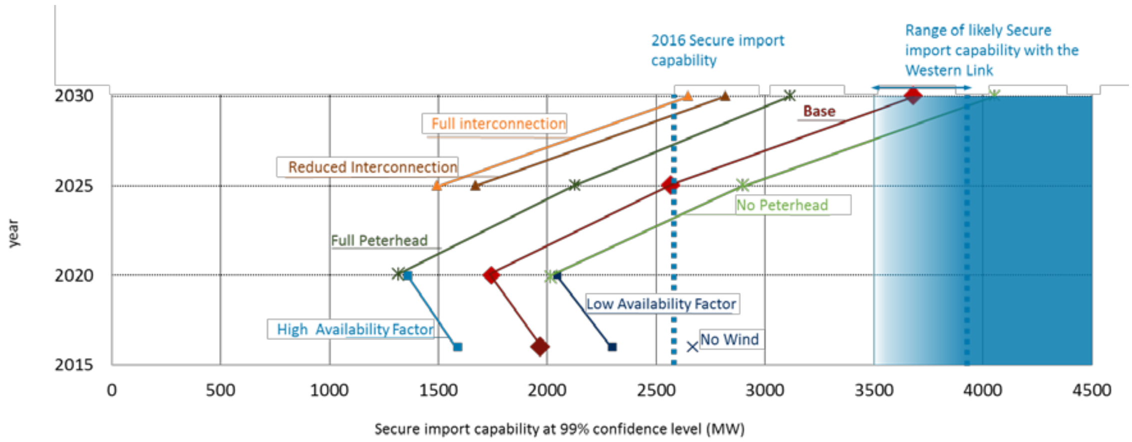
The secure import requirements for the main scenarios are summarised in Figure 14 (a) and the additional sensitives in Figure 14 (b). The requirements needed for a 99% confidence of serving peak demand vary from 1322MW in 2020 assuming full availability of Peterhead and no further closure of existing generation, through to 4054MW in 2030 with Hunterston, Torness and Peterhead all closed. It also shows the current secure import capability of 2.65GW, and an estimate of the value after commission of the HVDC Western Link project of 3.9GW under current network conditions. Whilst 3.9GW may be feasible at present, the secure import capability is affected by more than just the network itself and published value with the Western Link commissioned is calculated under system conditions expected for the second half of the current decade, notably with continued operation of Torness and nuclear and coal generation in the north and midlands of England.

Discussion with industry suggests that the likely evolution of the generation background during the 2020s will further impact on several of the relevant power system constraints. Closure of some stations in Scotland and England may relieve certain constraints, for example freeing up thermal capacity on critical transmission circuits, but may tighten other constraints such the potential for voltage dips during a fault. Whilst power flows above 3.5GW can be achieved with the Western Link, they place greater constraints on other aspects of system operation which may, for example, require precise settings on transmission equipment elsewhere in Britain. Under some future scenarios the binding constraint on getting power into Scotland may be a limit on a circuit as far south as central England, for the reason that high levels of import into Scotland depend on being able to move power from southern England into central England and then onto northern England. For these reasons it is likely that there will be a need for further secure import capability, or new schedulable generation in

Scotland by 2030 (sooner if Scotland's existing power stations close earlier) in order to be certain that peak demand in Scotland can continue to be met.



(a)



(b)

Figure 14: Secure import capabilities required to provide 99% confidence level of meeting peak demand for all sensitivities. (a) Shows the impact of the combination of high and low wind penetration and peak demand sensitivities in each year. (b) Additional sensitivities based on the Low Wind High Demand case for each year. Figures also show the secure import capability of the current transmission system, and an indication of the likely import capability (and range of uncertainty) with connection of the HVDC Western Link.

The key factor affecting the need for new transmission capability (or new generation) is the continued operation of the remaining three large power stations in Scotland. This depends on economic conditions and the condition that operators expect in future years. Capacity market contracts awarded to Hunterston and Torness provide some reassurance that they are expected to remain operational until at least 2021 as closure would involvement the payment of a significant penalty. However Peterhead has no capacity market contracts and no formal requirement to continue operating beyond 2017 and SSE has noted in early 2017 that it will review options for the future of Peterhead over the coming year[39]. Even where power stations have given no indication of closure, there remains a risk that economic conditions may change quickly, and at present there is no formal requirement for advanced notice over closure. The impact of this was illustrated in early 2016 when Fiddlers Ferry coal station in Yorkshire made public a proposal to close at the end of March. The first official notification was a statutory consultation with the workforce over redundancy[40] issued in early February. Negotiations with National Grid over contracts continued until 30th March[41] leading to the position where the continued operation of the station in two days' time was unknown. The operators of Fiddlers Ferry proposed closure despite holding a CM contract, and noted a willingness to pay a £33M penalty to break the CM contract. Following this, the UK Government has tightened the rules around termination fees in an attempt to ensure that operators do not consider this as a choice in future[42].

Even if commercial conditions are such that continued operation of particular stations is financially viable, experience from France in autumn 2016 gives an example of how other concerns intervene. A fault in one French nuclear reactor led to the temporary shutdown of around a third of the 70 Nuclear reactors in France whilst safety checks were carried out on all units. The likelihood of a similar situation occurring in Britain leading to early and unexpected closure of both nuclear stations in Scotland is impossible to calculate. However, the French case shows that diversity at all levels of security provision can help mitigate the impact that any one events can have.

Other aspects of security of supply

This paper has focused on peak demand security of supply, and shown that Scotland's generation fleet and transmission network will provide generally high confidence of meeting peak demand until the closure of all three remaining large power stations. However, away from peak demand there are a range of other issues which are of growing importance.

Black start recovery: the complete shutdown of the electricity system is a highly unlikely event, but one with a huge impact. National Grid maintains contracts with a number of 'black start' stations round the country. These stations have the ability to restart without an external source of power and set up power islands. The process of recovering from a black start currently involves setting up a number of power islands across the country before linking them together to reform the fully synchronised system. With conventional power stations closing, there is a reduction in the number of stations that are likely to be available to support a black start, leading to an increase in the likely time to get the system back up and running. Nuclear stations are unable to support black start as they require an external power supply to start up. Ensure recovery time across GB, including in Scotland is possible within acceptable time scales will be an important part of wider security of electricity supplies.

The summer minimum: low levels of demand brings different issues to those associated with peak demand. In particular the ability to control voltage across the system. During periods of low demand, many conventional generators will shut down as the low prices associated with low demand will tend to make it uneconomical to sell power. However, an important ancillary service that large generators provide is the ability to supply *reactive power* to the network, a service which can be used to control the voltage in that part of the transmission network. In general voltage problems can be managed by the installation of new reactive power equipment, a process than can be achieved in

[39] SSE press release, 6th February 2017, http://sse.com/newsandviews/allarticles/2017/02/2017-capacity-market-year-ahead-auction/
[40] Fiddlers Ferry press release (03/02/16) http://sse.com/newsandviews/allarticles/2016/02/consultation-on-future-of-sses-fiddlers-ferry-power-station/
[41] Fiddlers Ferry press release (30/03/16) http://sse.com/newsandviews/allarticles/2016/03/fiddlers-ferry-coal-fired-power-station/
[42] UK Government response to 2016 Capacity Market consultation: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/521301/Govt_response_to_March_2016_consultation_FINAL.pdf

relatively short time scales of a year to 18 months and at relatively low cost. Without access to conventional generators other alternatives are being developing which include greater use of wind farms to provide reactive power support, a service they may be able to provide even without wind.

Outages for maintaining and upgrading the transmission system (and the summer maximum): whilst an intact transmission network may be capable of providing the required level of security for winter peak demand, there are a number of specific challenges which may remain a problem at other times of year. In particular, all transmission assets require maintenance which will occasionally take them out of service, and upgrades to the system also require planned outages. Many of these projects need extended periods and during this time the capability of the transmission network is reduced. Historically these outages have been taken during the summer months when peak demand is expected to be significantly lower than in winter. However, the number and complexity of planned outages is increasing and they are becoming challenging to accommodate in a manner that maintains the required level of security throughout the year. Understanding peak demand expectations in summer, and the possible maximum import (and export) needed to provide security of supply at the summer peak is important in planning the 'outage schedule' for each year and ensuring that the network can be upgraded effectively.

The effect of assuming independence between wind and demand

The study makes the assumption that the main variables – availability at each individual conventional unit, overall wind resource availability, and peak-demand level – are independent of each other. This ignores some potential correlation, importantly between peak demand and wind availability. The assumptions of independent matched those used in generation adequacy studies such as National Grid's EMR Electricity Capacity Report up to 2015[43] where zero correlation was assumed as a base case with some sensitivities used to study the impact of a small negative correlation between demand levels and wind availability at times of high demand[44]. Whilst there has been discussion over the probability of a negative correlation between wind availability and demand for a number of years, the rarity of high-demand events makes it impossible to draw statically significant conclusions. Despite this, it is plausible that some weather conditions which lead to very low temperatures (and by implication, high levels of electricity demand) are also associated with low wind, for example winter anticyclone conditions.

Work carried out to support National Grid's Electricity Capacity Report 2016 has suggested that some level of correlation between wind and the level of demand should be included in generation adequacy calculations. The base case used in 2016 includes a scaling down of wind output for periods where demand is greater than 92% of the ACS peak with wind availability linearly scaled from full availability to either 90% or 80% available for very high demands above 102% of the ACS peak. The results show a relatively small impact on the level of de-rated generation capacity that is required to meet the LoLE generation adequacy standard.

To show the potential impact of the same assumptions in this work. The same process is applied to the 2016 base case results with wind availability being scaled down at higher peak demand outturns. This involved adjusting the Monte Carlo trial process to create a dependency between peak demand outturn and wind availability. Two sensitivities were used in line with the National Grid work: linear reduction of wind availability for demand levels higher than 92% of the ACS peak reducing to (a) 90% and (b) 80% at ACS peak at 102% of ACS peak. Without correlation between demand and wind the mean value of wind availability is 37% representing the average capacity factor during winter of the

[43] National Grid EMR Electricity Capacity Report: https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/47/Electricity%20Capacity%20Report%202016_Final_080716.pdf See page 59.

[44] For example National Grid EMR Electricity Capacity Report, Low Wind (at times of cold weather) sensitivity https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/47/Electricity%20Capacity%20Report%202016_Final_080716.pdf

input data. For the two sensitivities with dependency between peak demand and wind, this drops to 34% and 31% respectively capturing the increased likelihood of low wind availability at times of high demand.

Figure 15 shows the import distributions for the 2016 base case and the three demand/wind correlation sensitivities. The inclusion of correlation between wind and demand can be seen to have a large effect on the lower tail of the distribution, whilst the impact on the upper tail is almost invisible. This is confirmed by changes to secure import requirements shown in Table 12. At the 99% confidence level, the increase in the secure import requirement is just 27MW for a 90% scaling, and 55MW for a scaling of 80%.

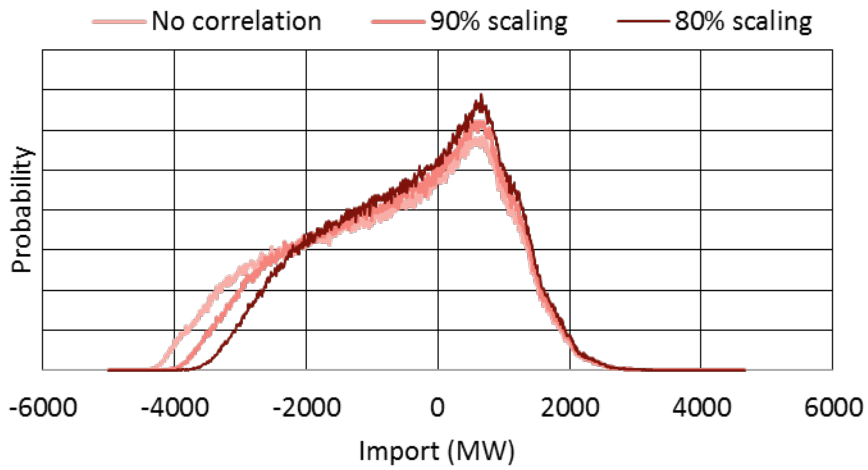


Figure 15: Impact of reducing wind contribution during trials with high peak-demand outturn

	90%	95%	99%	99.90%
2016 - Base	1130	1429	1969	2531
High demand wind scaling: 90%	1173	1465	1996	2551
Increase in secure import requirement from base	*43*	*36*	*27*	*20*
High demand wind scaling: 80%	1218	1503	2024	2574
Increase in secure import requirement from base	*88*	*74*	*55*	*43*

Whilst it may be expected that the addition of correlation between peak demand and wind availability would increase secure import requirements, the fact that the increase is marginal is reflective of the ranges of each variable in the analysis. Whilst peak demand outturn varies by only a few hundred MW, the availability of wind generation varies from nearly zero to around 90% of the total installed capacity, a range of between 5GW and 20GW across the scenarios and sensitivities studied. Therefore the secure import requirements are driven predominantly by trials with low wind availability even without an assumption of correlation.

Conclusion

The study shows the importance of considering the power system as a whole and considering both generation adequacy across GB and transmission requirements when analysing Scottish peak demand security of supply. It shows that the existing transmission network and the Western Link are likely to provide very high confidence levels of meeting peak-demand in the near future whilst Peterhead, Hunterston and Torness remain operational. Even after the closure of Peterhead and of one or two of the two nuclear stations, power flows at time of peak demand will be generally within feasible limits. However this high level of confidence depends on GB remaining secure overall, and therefore a failure to provide sufficient generation capacity across the whole system may, in the short to medium term, prove to be a greater risk to the ability to serve Scottish peak demand.

Once two of the three remaining large scale power stations close, import requirements into Scotland at the 99% confidence level are likely to be close to the limit of the system. At this point further transmission upgrades are likely to be needed, and unless new dispatchable generation can be attracted to Scotland the closure of all three existing stations will require greater import capability to maintain high confidence of meeting peak demand. Timescales to plan and build new transmission assets can be as long as a decade in some cases and therefore coordinating any future upgrade requirements with unknown (and unknowable) future network condition remains a major challenge.

Other aspects of security of supply such as Black Start, voltage management and operation of the system during summer months must also be considered, and poly makers should find a way to engage with these issues despite their technical nature. In the short term ensuring these broader security of supply and resilience issues receive their due attention is vital.

In answer to this study's main question: *What transmission import capability is required into Scotland in order to provide confidence that peak-demand for electricity can be met?* The results can be summarized as follows:

- The first condition of Scottish peak demand security-of-supply is that there is adequate generation across GB to meet the GB peak demand. Without system-wide security-of-supply, no part of GB, including Scotland, can be considered secure.
- In the winter of 2016/17 with Peterhead, Hunterston and Torness power stations operational, the Scottish generation fleet combined with the transmission secure import capability of 2.65GW provides in excess of 99.9% confidence of being able to meet peak demand in Scotland (assuming sufficient generation is available in rGB).
- If there is to be the same degree of confidence in meeting peak demand in Scotland as today, the closure of Hunterston power station, expected in 2023, and Torness power station, expected in 2030, will increase the need for secure import capability. If Peterhead power station remains operational at current levels, modelling suggests that the 2030 secure import requirements is between 2.9GW and 3.7GW in order to provide 99% confidence of meeting peak demand.
- The closure of Peterhead power station will increase the secure import requirement by between 350MW and 400MW.
- This increased requirement for secure import capability will be partially met by the commissioning in 2017 of the western HVDC link between Hunterston and Deeside in north Wales which will increase the secure import capability by around 1.2GW. However very large imports into Scotland, of the order of 3.5GW and larger, may require increased coordination in the operation of the transmission system across the whole of GB or further network reinforcements.

- There is likely to be a need for further secure import capability, or new schedulable generation in Scotland by 2030 (sooner if Scotland's existing power stations close earlier) in order to be certain that peak demand in Scotland can continue to be met.

In light of these results, our key conclusion is that, given the time scales normally required for transmission and generation projects, it is important that system planners, regulators and policy makers ensure that further examination of the requirements and potential options begins soon. It will be important to estimate the required capability of the transmission system whilst taking full account of the impact of the large wind fleet in Scotland, and the reduction in the number (as well as the capacity) of large dispatchable and baseload units in Scotland. Finally the increased uncertainty introduced into system operation by further interconnection with neighbouring markets must be fully considered when considering the role that these interconnectors will play in Scottish and GB security of supply.

Glossary

Average Cold Spell (ACS) peak demand	The level of peak demand that is estimated to have a 50% chance of being exceeded in a particular winter due to weather effects alone. It provides an estimate of the underlying demand level that can be compared across winters.
Capacity Credit	A measure of the additional demand that can be met securely due to one particular generator. There are a number of ways of measuring capacity credit, each of which indicated the ratio of additional demand to installed capacity of a generator. Effective Firm Capacity is one measure of capacity credit currently in use for wind power.
Contingency Balancing Reserve	A set of reserves held by the system operator to provide additional generation adequacy. Two forms of contingency balancing reserve were used in GB between 2014 and 2017.
Demand Side Balancing Reserve	Demand response reserve held for use in times of system stress and contracted by National Grid during the winters of 2014/15 – 2015/16. (Whilst there was the option of contracting during the 2016/17, National Grid choose not to do so)
De-rated capacity	The system-wide sum of de-rated capacity at each unit, where for each unit its total capacity is scaled down by (a) an availability factor for conventional generators; or (b) the EFC for wind farms.
De-rated Margin	An estimate of the margin between the 'average' expected generation availability in the system around the time of peak demand minus the ACS peak demand of the system, presented as a percentage of the ACS peak.
Loss of Load Expectation	The number of hours per years, as a long term average, that a system will have insufficient generation to meet demand.
Operating Reserve	Additional generation, beyond that required to simply cover demand, which must always be carried to ensure the system can operate in a secure way. This is added to ACS peak demand when determining LoLE and de-rated margin values.
Regional Capacity Credit	The reduction in secure import requirement created by the addition of a generator to a region of the power system as a fraction of that generators installed capacity whilst leaving the level of security of supply for that region unchanged.
Secured events	A set of events such as the loss of a generator due to a fault, or the automatic tripping of an overhead line, after which the power system must continue to operate within all limits. The events against which the system must be secured are defined in the Security and Quantity of Supply Standard.
Secure import capability	The ability of the transmission network to import power into a region of the power system after a secured event has occurred.
Secure import requirement	The import secure import capability required of the transmission system in order to provide a specified level of confidence of meeting peak demand in that region.
Supplementary balancing reserve	Large generators held outside the energy market to support security of supply if required. Contracted by National Grid during the winters of 2014/15 – 2016/17.
Transmission system	The high voltage, interconnected, electricity network defined as all voltages of 132kV and higher in Scotland and all voltages of 275kV and higher in England and Wales.

Wind Effective Firm Capacity (EFC)	An estimate of the de-rating factor to apply to wind generation in the de-rated capacity and de-rated margin calculations. It gives an indication of the level of 100% reliable conventional generation which would be needed to replace the entire wind fleet and leave the system with the same overall level of security. One thing to note is that, due to correlations between the availabilities of power from different wind farms, the Wind EFC changes (gets smaller) as the wind fleet gets bigger.