Security of electricity supply in a low-carbon Britain

A review of the Energy Research Partnership's report "Managing Flexibility Whilst Decarbonising the GB Electricity System"

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1 Introduction

The Energy Research Partnership's (ERP) recent project on "Managing Flexibility Whilst Decarbonising the GB Electricity System"[1] involved the construction of a model aiming to analyse scenarios for different energy mixes in GB in 2030, incorporating the estimated costs of energy from different sources of electricity, and to derive the additional costs that would result from the requirement to balance the system at a half-hourly resolution. In the published report of the project, a continuum of possible generation mixes is evaluated to determine, on the basis of the modelling done, which mix of generation would seem to provide the cheapest total system cost after this balancing requirement is met while still meeting different carbon reduction targets.

The ERP's report comes at a critical time in discussions around the requirements placed upon the GB electricity system by the need for decarbonisation, with recent relevant publications including:

- The National Infrastructure Commission's (NIC) report on Smart Power[2] considering the future balance of supply and demand;
- National Grid's System Operability Framework[3];
- A report for the Committee on Climate Change (CCC) on the value of flexibility in a decarbonised grid[4].

This review assesses the value of the ERP's report towards future energy policy for the GB network, within the current context of the need to ensure security of supply while reducing the carbon intensity of electricity.

The authors have also recently published a UKERC working paper on Low Carbon Networks[5], which addresses the parallel issues in network development and operation necessary for the low-carbon transition in electricity.

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1 http://erpuk.org/project/managing-flexibility-of-the-electricity-sytem/

2 https://www.gov.uk/government/publications/smart-power-a-national-infrastructure-commission-report

3 http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/System-Operability-Framework/

4 https://www.theccc.org.uk/publication/value-of-flexibility-in-a-decarbonised-grid-and-system-externalities-of-low-carbon-generation-technologies/

5 http://www.ukerc.ac.uk/publications/new-working-paper-on-low-carbon-networks.html

2 Additional costs arising from a need for flexibility

Discussions around the future mix of generation for the supply of electricity in Great Britain often revolve around the different costs of energy for low-carbon generation. These fall into 3 broad categories of sources: renewable sources such as wind turbines (onshore and offshore), hydroelectricity and distributed photovoltaic solar panels; nuclear power from both current and future reactor designs; and classical 'thermal' power sources with the carbon impact mitigated through the use of biomass fuels and/or carbon capture and storage (CCS).

A number of studies[6] over recent years have attempted to reconcile the costs of these different forms of electricity generation by compiling a 'levelised cost of energy' (LCOE) which allows a direct comparison of sources by analysing the financial background of each – capital cost, operation and maintenance cost, fuel cost, expected annual capacity factor, lifetime, etc. – to determine the unit cost of electricity that would need to be borne by the end consumer to ensure investment in that form of generation.

However, such studies do not provide the complete picture of the cost of the electricity system. There is a need not only to ensure that our *energy* demands as a whole are supplied, but also that our instantaneous demands for *power* can be met on a second-by-second basis and the system can be operated securely. The energy budget does not include the requirement to have an operable, stable and reliable system at every moment in time where, in reality, additional sources of flexibility are required to ensure secure system operation. Some forms of generation (particularly thermal sources such as gas turbines) are particularly able to provide controllable short-term changes in output to match variations in demand, while renewable sources are highly dependent on their respective physical resources. Operation of current nuclear reactor designs is expected to be controllable and reliable, but unsuited to rapid changes in output. Similarly, the introduction of carbon capture to controllable thermal plant may impose additional restrictions on that flexibility if, for example, the efficiency or cost of the carbon capture process is affected by changes in plant output. If given sufficient incentive, this flexibility may be added by oversizing the capture plant and adding buffering, allowing it to run independently from the generation and offer flexibility services. Such incentives hence need to be available at the project design stage.

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[6] Including several analyses commissioned by DECC, such as by Mott Macdonald in 2010, Arup in 2011 and Parsons Brinckerhoff in 2013, the last of which is used in the Energy Research Partnership (ERP) modelling discussed in this paper.

As the proportion of fossil-fuelled thermal generation on the GB system reduces in line with carbon reduction targets, there is a need to replace the 'ancillary services' these generators provide and, as a consequence of the characteristics of current nuclear designs and intermittent renewables such as wind and solar, an increasing need to procure additional volumes of services such as reserve generation which is capable of being dispatched to meet shortfalls in supply. In addition, the total generation on the system may exceed demand – such as during periods of high wind speeds coincident with low demand in the early hours of the morning or windy, sunny Sunday afternoons in summer – and this means that low-carbon generation may need to be curtailed, which in turn increases the cost per unit of energy (both for being made available and actually utilised) from those sources.

3 Establishing an objective and determining the optimal generation mix

Any model seeking to optimise our future electricity or energy systems needs to grapple with the well-established 'energy trilemma' – the need to balance the requirement for security of supply against the goals of reducing national carbon emissions while ensuring costs of energy are minimised. In power system modelling it is common to establish security as a constraint by requiring that generation meets demand for a given minimum number of modelled time steps. The modelling might also recognise that most generation capacity is physically located away from where the demand is and, as a consequence, its utilisation also depends on sufficient network capacity. In general, therefore, development of new generation resources might also require investment in additional network capacity, adding to the total cost of the generation.

The ERP study does not go into the detail of each power station or power park, or its location on the network, but does present the results of modelling of generation and demand balancing on the basis of 17568 separate half-hours (i.e. one year) of demand and available wind power observed in 2012. Wind output is scaled up to match the wind generation capacity being assumed in each of a number of different future scenarios. Other energy system optimisation models such as TIAM-UCL[7] establish total carbon emissions as a fixed constraint (i.e. at a point defined by international emissions targets). Instead the ERP model applies a carbon price and so includes implicit emissions costs within a minimisation of the short-run cost of generation for the given capacity mix. The outputs of the model then include both a cost and a carbon intensity of generation (the amount of carbon emitted per unit electricity generated) which may or

[7] https://www.ucl.ac.uk/energy-models/models/tiam-ucl

may not meet a given carbon target, but will be the cost-optimised solution given the carbon price and other prices associated with all the available forms of generation.

A model of the dispatch of generation can be very complex. In particular, it might include ‘real world’ constraints such as the maximum rate of change of output, the minimum stable output of a thermal generating unit or the minimum time that a unit should remain off once it has been shut down. The model developed by the ERP is relatively simple in this respect, being a linear optimisation which does not model these complexities. However, in order to take account of the different efficiency of part-loaded operation, our understanding is that account was taken of Minimum Stable Generation limits and what this would mean for the amount of capacity operating at part-load. The model is judged by the investigators to give reasonable results but to do so in less time than a more detailed model would require. It also does not seek to optimise the generation mix but instead explores a large number of given combinations of capacities for nuclear, wind and CCS plant.

An optimal generation mix also requires an investment trajectory and investment decisions taken at any given point on that trajectory should be based on the best information that is available at that time. For example, in Britain we already have a certain amount of wind generation which, at the time at which it was developed, was clearly the cheapest form of low carbon electricity. The view on how we got to our current situation is often omitted from long-term analyses. Indeed, part of the point of the ERP study is to re-evaluate what now appears, all reasonable things considered (as far as practically possible in a quick study), to be the cheapest form of low carbon electricity. Supply chain constraints and the need to progress with decarbonisation create a requirement to make tangible, short-term progress in spite of uncertainties, and the costs of a technology (or delays in delivering it) will make a difference to the overall cost and energy mix. The Committee on Climate Change recognises that there are “technical limits on the amount of low carbon investment that may be achievable in any single year”[8] and that it is the cumulative impact of carbon emissions which needs to be considered as opposed to the emissions in a future target year. The 2015 Paris Agreement resolves “to enhance the provision of urgent and adequate finance, technology and capacity-building support by developed country Parties in order to enhance the level of ambition of pre-2020 action”[9] highlighting the requirement to invest in a trajectory of decarbonisation and an evolving energy mix as opposed to focusing simply on a fixed target date and emissions level.

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[8] https://www.theccc.org.uk/tackling-climate-change/reducing-carbon-emissions/carbon-budgets-and-targets/

[9] UN Framework Convention on Climate Change, Adoption of the Paris Agreement https://unfccc.int/resource/docs/2015/cop21/eng/l09r01.pdf

Given that there is already 11GW of wind generation capacity in Britain, it does not seem to be of significant value to study scenarios, as the ERP work appears to, where wind is not be part of the mix. At the time we started developing wind in Britain, nuclear power and CCS were not regarded as viable and solar PV was much more expensive than now. Solar PV is not addressed as a dimension of the ERP modelling. Further to this, the modelling shows that simply increasing wind capacity also increases the amount of wind that would have to be curtailed in high wind situations, so the marginal 'carbon reduction value' of wind declines. There is no assessment made of curtailment due to grid constraints, as the model assumes a copper-plate grid, something that should be taken into account if readers want to compare modelled volumes of curtailment with operational experience to date in GB. As a consequence of transmission capacity investments such as overhead line reconductoring, the commissioning of series compensation and the West Coast HVDC link, network-related curtailment should reduce significantly in the next few years. Further significant network upgrades planned for the next 15 years are already in scoping and are likely to be progressed if the mix and location of generation requires it. The ERP mixed scenario with high penetration of low carbon generation in 2030 shows a curtailment of wind energy of 4%. This compares to 3.2% in Ireland in 2013 with 2.5GW of wind generation against a 6.4GW peak demand[10].

4 Generation costs and uncertainties

The future costs of a technology are subject to a number of uncertainties, including (but not limited to) load factors, fuel prices, hurdle rates and learning factors. The costs associated with a new or emerging technology are highly dependent on the level of support given as this will affect the learning and cost reduction rates. The results of the 2013 Parsons Brinckerhoff study[11] used in the ERP model, for example, show round 3 offshore wind at £120/MWh for a project starting in 2013, whereas the previous study by Mott Macdonald in 2010[12] gives a figure of £190/MWh for the same projects starting

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[10] Eirgrid, Annual Wind Constraint and Curtailment Report, 2013 http://www.eirgridgroup.com/site-files/library/EirGrid/Annual_Wind_Constraint_and_Curtailment_Report_2013.pdf

[11] DECC, Electricity Generation Costs 2013

https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223940/DECC_Electricity_Generation_Costs_for_publication_-_24_07_13.pdf

[12] DECC, UK Electricity Generation Costs Update, June 2010.

https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65716/71-uk-electricity-generation-costs-update-.pdf in 2009. Early Contracts for Difference for offshore wind have been given at £114.39 and £119.89/MWh[13]. This illustrates both the potential magnitude of savings due to learning and difficulty of forecasting costs. Assumptions around these reduction rates are also significant for the LCOE of new nuclear in the Parsons Brinckerhoff study, and are particularly pertinent to modelling which includes assessment of Carbon Capture and Storage, for which costs remain highly uncertain due to the lack of existing projects integrating CCS into commercial generation. The modelling conducted by ERP demonstrates the potential impact these sensitivities may have on the resulting optimal generation mix: "there are troughs of near minimum total system cost that extend away from the optimum towards an entire CCS solution or where 20GW of wind can replace 5-6GW of nuclear each with less than 3% added cost."

In practice, there are many uncertainties around long-term generation investment and the market would probably hedge – a rational and prudent investment portfolio would not end up dominated by one form of generation. There are also other issues than cost, such as around planning constraints, though such issues would normally be expected to feed into the cost of capital. The key point remains that the technology costs are similar enough that a change as small as 3% makes a big difference to the apparent optimal solution. For this reason, the ERP study would ideally also have included cost sensitivity studies to explore the impacts of changing future costs.

5 The future role of interconnection, storage and demand-side management

In evaluating the potential role of storage, the ERP study uses a simplified calculation (as opposed to the BERIC tool used in the main analysis) in order to explore storage, which explores the fundamentals of the 4 main plant types. The study looks at 30GW of pumped storage being added to the model, but dismisses the potential role of demand-side participation (DSP) due to its applicability for timescales of only up to around 6 hours. However, we would argue that DSP represents a potentially extremely cost-effective contribution to system balancing. On the other hand, the value of DSP is more complex than would be captured by a simple storage dispatch model as it represents a wide variety of possible technologies, end-user behaviours and possible incentives. A deeper evaluation of the combined value of DSP with short-term storage alongside increased interconnection capacity is required.

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[13] DECC, Contracts for Difference Allocation Round One Outcome, February 2015 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/407059/Contracts_for_Difference_-_Auction_Results_-_Official_Statistics.pdf

Ideally, the ERP modelling would have considered scenarios with a deep decarbonisation of heat demand, which, in one possible future, would imply increasing electrification of heat and a significant growth in peak electricity demand. This in turn would add a greater DSP potential to the system although it may also be recognised, as is noted in the ERP report, that the greatest value would come from an ability to shift demand (through use of storage) between seasons, something that is not yet credible. The report highlights the importance of Combined Heat and Power (CHP) emissions, which further illustrates the importance of heat demand. It is unlikely, however, that any such systems could provide storage on the 2-3 week timescales argued by ERP to be key to security of supply due to extended periods of low wind speeds. This is the point at which European-level coordination of storage, including not only pumped storage but also conventional hydro resources from which energy can be very flexibly converted into electricity, as envisaged by the European Commission and facilitated by European transmission network enhancement, could operate. The effectiveness of this will depend on the level of correlation of generation and demand in interconnected states and the extent of development of further interconnection. Preliminary modelling work which looks at the variability of wind generation against demand in neighbouring Member States[14,15] indicates a significant value for interconnection in this context so it is a pity that the ERP study largely disregards it. However, some modelling of current interconnection suggests that, under current market conditions, interconnector flows should not be relied upon to always support GB security of supply at times of system stress[16].

6 Reserve, response and system inertia

The ERP report notes that "taking proper account of reserve and response is likely to make a significant difference to the important parameters in a scenario such as cost and in particular CO_2 emissions." It also states that "the need for fast reserve and STOR [Short Term Operating Reserve] are most critical and dependent on technology choice"

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[14] I. Staffell, R. Green. Harvesting North Sea wind: How big is the crop and who wants it? Hubnet Smart Grid Symposium, Birmingham, September 2015

[15] TWENTIES Project, Drivers for offshore network design and benchmark scenarios, Deliverable 2a, April 2012

[16] Pöyry, Analysis of the correlation of stress periods in the electricity markets in GB and its interconnected systems: A report to Ofgem. March 2015 https://www.ofgem.gov.uk/ofgem-publications/75231/poyry-analysis-correlation-tight-periods-electricity-markets-gb-and-its-interconnected-systems.pdf

but does not address this uncertainty in the services which future generation types may be capable of delivering. It is not clear the extent to which new nuclear designs or CCS may be capable of providing flexible output. CCS may require an over-capacity of carbon processing, and, although nuclear power stations are theoretically capable of providing it, there may be opposition to nuclear flexibility from the Office for Nuclear Regulation. However, one result of the ERP's modelling is to show that the predicted cost of reserve and response, even under high renewable scenarios, is a relatively small proportion of the total system cost.

The report concludes that "the implication of valuing firm capacity and ancillary services is that it would be helpful to consider changing the retail market pricing structure to reflect the actual costs". However, disappointingly, this assertion is not supported with evidence. At present, we have separate markets for separate services, e.g. capacity, reactive power, frequency response, and locational network constraint relief. This might mean that a generator that, for example, looks expensive in the capacity market might not get contracted even though, all services considered, it might represent the cheapest solution. On the other hand, if there were not separate markets, this might discriminate against parties that can only offer certain services and not all of them and would make it difficult to discover the market price for any one service. Nonetheless, there may be value in future in running tenders for different markets simultaneously and awarding contracts based on total value for a package of services.

System inertia – the electricity system's stored kinetic energy which can be accessed rapidly in response to disturbances such as unplanned losses of generation – is set to reduce as the proportion of non-synchronous generation on the system increases. The ERP model base case makes the assumption that system inertia can be lowered from current levels of around 180 GW.s to 90GW.s, based on a doubling of the 45 GW.s theoretical figure derived from proposed new rate of change of frequency (ROCOF) protection settings. While this is a reasonable starting point, this inertia constraint becomes a significant issue in high renewables scenarios (as it implies a need to procure additional system inertia from other generators and to limit output from renewables), so it is important to test what this constraint is likely to actually be. Additional studies should investigate the effect of further relaxation of ROCOF settings or the frequency nadir constraint and what they imply for minimum system inertia. Ideally, such constraints should be set as the result of detailed and credible dynamic simulations. In our view, there is insufficient evidence from the ERP model, and inadequate exploration of dynamic conditions, to support the assertion that "assuming that the implementation of the change to the grid code is successful the issue of low inertia has effectively been solved". There is also the question of whether – as some generation owners have argued – generators should be paid for inertia as an ancillary service. For example, it may be noted that, for synchronous machines, it is an inherent feature – a spinning turbine provides a contribution to system inertia irrespective of whether that is offered as a service or not[17].

As previously mentioned, it is also noted that there are no unit commitment constraints in the model (such as minimum stable generation levels, start-up/shut-down costs and ramping limits) which would likely add further costs to operation of the system. However, we might add that whether such costs should be attributed to any one particular technology is open to debate. For example, it is typically the large thermal units, such as unabated combined cycle gas turbines, nuclear sets or future CCS units, that have such ramping and on/off time constraints meaning that other sources of power might need to be curtailed. Analysis of power system flexibility considered as a whole is key to operational planning of the future system and helps to quantify the specific benefits of flexible generation, storage and interconnection in achieving a specific carbon intensity of generation[18]. If it is desirable to increase the flexibility of future generation technologies such as new nuclear, CCS or even renewables, then it is key to determine the desired parameters of such technologies as early as possible in order to capture this need in design specifications, rather than imposing it retrospectively or at a late point in the development process.

7 The message for policy makers

In spite of the areas in which we have highlighted some modelling limitations, overall we believe that the ERP model presents a useful high-level view of the future issues around system balancing and flexibility in the provision of electricity in a scenario with increased levels of low-carbon generation, and illustrates the scale of the challenge faced. We feel the work is highly creditable and, even if it cannot possibly answer every question, take the view that this study is useful in moving the debate forward and, because results from simpler models are often easier to explain than those from more complex models, can still add value relative to a longer and more detailed study, especially if results' sensitivities to different inputs or assumptions are explored. In respect of this particular study, the key outcome, however, is not that the modelling should be used as evidence to support one particular generation mix over another, but that it demonstrates that the current uncertainty in costs of different generation sources

[17] It would be interesting to see if operators of synchronous generators directly coupled to the AC system would be capable of withdrawing an 'inertia service' if they weren't paid for it.

[18] E. Lannoye et al (2015) Assessing power system flexibility for variable renewable integration: a flexibility metric for long-term system planning. CIGRÉ Science and Engineering, Vol. 3, October 2015.

is larger than the extra cost as arising from the need to balance the system apparent in the modelling. With current carbon intensity goals we do not have the luxury of waiting to determine those costs accurately before deciding the trajectory of generation investment in this country. In this respect, a diverse mix of sources appears to continue to be the wisest choice until the true costs – and trajectories of learning and economies of scale that may reduce them – become more apparent not only for the generation sources discussed, but also for storage, demand-side management and increased interconnection with the evolving single European market.

The modelling and the associated report make no comment on how different generation mixes could be achieved, and the feasibility of either large amounts of nuclear power or CCS being delivered by 2030 is open to question. Only one new nuclear plant is close to a final investment decision, with operation not planned until 2025 at the earliest. Meanwhile, the onshore wind industry is currently threatened by a weakening of financial support by the current government in Westminster, and the long-term impact of the still new CfD framework on offshore wind development is unclear. In these respects, there is a significant gap between what the modelling suggests would be feasible generation mixes in 2030 that meet decarbonisation targets and any trajectory that can readily envisaged under current energy policy. While government support for nuclear power is in line with the recommendation of the report, the volume of new nuclear plant currently foreseen falls some way short of the level modelled.

While we would counsel the reader against interpreting the results of the ERP modelling as being a clear case for support of one form of generation over another, there remain important conclusions to be drawn. Namely:

- a significant volume of new low-carbon capacity is required, but the exact amount depends on what can be achieved with DSP, and in particular, interconnection and development of a single European electricity market that includes appropriate incentives for decarbonisation and security of supply treated on a Europe-wide basis;
- the differences in economic value of different generation mixes are smaller than the uncertainties in costs of those individual sources, and there is a strong need for ongoing analysis which tracks the evolution and trajectory of those costs, in particular around offshore wind, nuclear power and carbon capture and storage;
- the cost of procuring response and reserve seemingly remains a relatively small proportion of Total System Cost and so should not be viewed as a key driver for policy;
- if new sources of flexibility are required, then these requirements should be set into the specification of developing technologies such as new nuclear, biomass, CCS and emerging techniques in wind power control, rather than

attempting to impose flexibility constraints retrospectively or at a late stage in the technology development process;

- the new capacity of low carbon generation required to be installed to meet emissions targets means that we do not have the luxury of waiting for certainty on relative costs;
- the long lead times of nuclear installations, and the lack of certainty over CCS development, mean that, in order to meet interim targets, the development of wind and solar PV installation should be continued, even if they subsequently do not turn out to be the long-term cost-optimal solution. However, it remains the case that new sources of reliably dispatchable capacity are essential to meet emissions targets over the coming years.

An interesting extension to the ERP work would be a fuller investigation of cost sensitivities to explore the above issues in more detail. Further modelling work commissioned in this space should take into account full energy system impacts, in particular the potential impact of heat demand under decarbonisation, as well as including a full assessment of system dynamics to ensure that a future electricity system acting under a proposed generation mix is operable and secure.

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