RAP™ Energy solutions for a changing world

Policy Brief: A Critique of the UK's[1] Capacity Market Proposals

Phil Baker and Mike Hogan

August 2014

RAP is concerned that the capacity remuneration mechanism proposed by the United Kingdom to solve its alleged generation[2] adequacy problem will harm competition more than necessary.

Below, we discuss the following concerns:

- The UK's analysis of its generation adequacy problem is likely incorrect;
- Ongoing balancing market reform might put the UK's need for a capacity mechanism into question;
- The capacity mechanism does not do enough to avoid major undue distortion of competition; and
- The UK could, and should, use a more appropriate measure to address its alleged adequacy problem.

1. Analysis of the UK's Generation Adequacy Problem

In making the case for the introduction of a capacity market, the Department for Energy and Climate Change (DECC) points to declining future plant margins brought about by the decommissioning of conventional generation due to emissions legislation and a challenging investment environment. However, while plant margins are likely to deteriorate in the immediate years ahead, DECC's analysis of how far they will deteriorate and the assumptions underpinning that analysis can be challenged.

The question whether the analysis of the generation adequacy problem is correct, contains a number of parts:

i. Is the proposed use of the reliability standard as a mandatory minimum and the translation of that standard into an implied target resource margin reasonable?
ii. Are the assumptions with regard to the capacity that is, and will be, available to meet its reliability standard correct?
iii. Is the design of the capacity market appropriate?

Each of these issues is addressed in more detail below.

Adequacy Problem Analysis

[1] Throughout this paper we refer both to the UK, by which we mean the British government as the party making the proposal, and GB, by which we mean that part of the UK power system known as Great Britain in which the proposed capacity market is intended to operate.

[2] In order to avoid confusion, we will follow the language used by the European Economic Advisory Group (EEAG), however, we believe that it is more appropriate to use the term "*resource* adequacy." "Generation adequacy" tends to put an emphasis on supply-side resources, while it is generally recognized that the achievement of adequacy depends, by far, not only on the availability of supply-side resources.

The Secretary of State for Energy has confirmed the capacity to be procured in the first auction to be held in December of this year.[3] The decision is based on the analysis set out in National Grid's *Electricity Market Reform (EMR) Electricity Capacity Report* (Capacity Report), which recommended that capacity at the upper range of 51.4 to 53.3 GW (before adjustments) should be procured.[4] The upper range figure was recommended on the basis that any contribution from interconnectors with continental Europe should be discounted in order to avoid an increased risk of failing to meet the reliability standard. This recommendation highlights flaws in the application of the reliability standard and in the treatment of interconnection, which together with other concerns about National Grid's analysis in the areas of generator availability and demand response are discussed below.

Application of the Reliability Standard

DECC introduced a reliability standard against which the amount of capacity to be tendered will be assessed. With a target of no more than 3 hours of loss of load expectation (LOLE) per year, the standard is high compared with those adopted by some Member States (MS), but not excessively so. For example, it is considerably higher than the Irish reliability standard of 8 hours, but the same as that adopted by France. Although security of supply standards are a matter for individual MS and therefore difficult to challenge from a European perspective, the proposed application by National Grid is overly-conservative in a number of areas.

Firstly, one must recognize that the year on year variability of the parameters that define outturn reliability will result in years when reliability is reduced, balanced by winters when reliability is enhanced. It is important therefore to measure performance in delivering the reliability standard over an extended period rather than for a particular year. However, National Grid's reluctance to include any contribution from interconnection in order to avoid the risk of not meeting the reliability standard suggests that the standard is regarded as an absolute floor below which reliability should never fall, rather than a long term average to be achieved (See further discussion below about the distinction between a target and a mandatory minimum LOLE).

Secondly, as LOLE relates to periods when there is a supply deficit, only those instances when demand to be supplied exceeds available supply should be counted when assessing performance against the reliability standard. However, National Grid's proposed methodology will result in normal operational measures deployed to avoid a supply deficit, such as instructing "maximum generation" or invoking emergency support from neighbouring systems, counting towards allowed LOLE. This will result in more generation capacity being procured than is necessary to satisfy the reliability standard and will effectively result in a higher average level of reliability being achieved than the headline figure suggests.

It should also be noted that the deployment of voltage reductions will count in terms of LOLE, which while reflecting custom and practice in Great Britain (GB), is not consistent with practice elsewhere and introduces yet another layer of questionable conservatism into the assessment. As applied, the GB reliability standard will therefore be considerably tighter than appears at first sight.

[3] See Davey, 2014
[4] National Grid, 2014

Generator Availability

In estimating plant availability, National Grid uses the average of a generator's maximum export across the December to February period over the last seven years, a rather different approach to that used in their annual winter assessments. The Capacity Report approach produces availabilities that seem low compared with those achieved internationally, and indeed appears to under-estimate the actual performance of the GB generation fleet. For example, the mean availability of combined cycle gas turbine (CCGT) and coal plant is taken to be 84 percent and 88 percent respectively, while actual availability over the two recent winter peaks was 86 percent and 92 percent.[5,6]

The issue of generator availability was raised by the EMR Expert Panel which, in their July 2013 report to DECC,[7] suggested that National Grid's assumptions were too low, especially for a future situation when plant would be strongly incentivised to be available. While recognising that obtaining information for well-incentivised electricity markets is difficult, the Expert Panel in their final report to DECC[8] refer to evidence that suggests availabilities of 96 percent and 93 percent for CCGT and coal plant respectively may be more appropriate. The Expert Panel's conclusions are supported by evidence from markets such as PJM Interconnection (PJM) in the United States (U.S.),[9] where commercial incentives encourage generation owners to deliver dramatically higher peak season plant availability than those assumed by National Grid. In the PJM market, peak season CCGT availability is over 96 percent and a comparable difference over National Grid assumptions can be seen across all technologies. The performance of the UK generation fleet prior to 2000, when stronger incentives were in place, substantiates the fact that there is no good reason to assume that British plant owners are incapable of delivering comparable performance. It is likely to be the case that as plant margins tighten, the prospect of higher energy prices together with the incentives included in a properly designed capacity mechanism, reinforced by reputational issues, will all tend to increase outturn availability to within the range typically found in other markets.

Interconnector Support

In their *EMR Electricity Capacity Report*, National Grid consider both a net "float" situation over interconnection with adjacent markets (750 MW import from the continent and 750 MW export to Ireland) and an import scenario (2500 MW import from the continent and 0 MW from Ireland), together with a range of sensitivities. However, while accepting that imports over peak demand periods are more likely than exports, they conclude that this cannot be guaranteed and that therefore a net float is the more "prudent" scenario to choose. This is despite recent and projected increases in interconnector capacity and the existence of emergency support arrangements with neighbouring transmission system operators (TSOs).

With the introduction of market coupling, flows to and from continental Europe will become more volatile and dependent on price differentials. In the event of a genuine capacity shortage in GB, wholesale prices would rise and energy would be imported. However, the overly conservative

---

5 National Grid, 2014

6 National Grid, 2013

7 DECC, July 2013

8 DECC, 2014

9 PJM historically refers to Pennsylvania, New Jersey, and Maryland, though the PJM Interconnection now includes all or part of 13 states and the District of Columbia.

position adopted by National Grid and DECC reflects a fear that a GB capacity deficit could coincide with similar conditions on the continent and that no support would be available on the day. While this is a possibility and emergency support arrangements are not firm, a probabilistic approach suggests that at least some discounted interconnector contribution should be assumed. To assume no contribution is inconsistent with the probabilistic approach adopted in calculating LOLE[10] and flies in the face of both actual experience and informed analysis, including that carried out by DECC's consultants. Identifying just what interconnector contribution to capacity should be assumed is beyond the scope of this paper. However, Pöyry, in a report commissioned by DECC,[11] suggests that interconnection with Europe would provide 62 percent of effective capacity, which would be equivalent to 2.3 GW of additional generation capacity this coming winter and possibly 3.8 GW by winter 2018/19.

In their final report to DECC, the Expert Panel challenges National Grid's conservative approach to interconnectors and refers to both qualitative and quantitative evidence that suggest interconnection can provide a significant capacity contribution, particularly in circumstances when plant margins are tight.[12] Interestingly, one of the sources quoted by the Expert Panel is National Grid's Interconnector Business who state that "additional interconnectors provide mitigation against shortages at times of system stress."[13] The Expert Panel also notes the importance of identifying interconnection contribution to capacity during periods when capacity margins are particularly tight, rather than simply analysing historic interconnector flows during the winter period, which is the approach taken by National Grid in their Capacity Report.[14] Historic interconnector flows will not reflect the recent introduction of market coupling, which can only increase the sensitivity of interconnector flows to price differentials brought about by tight capacity margins and therefore increase imports.

The concerns behind National Grid's conservative approach to interconnection contribution highlight the need to move toward regional resource adequacy assessments, as proposed by European Network of Transmission System Operators for Electricity (ENTSO-E), the Agency for the Cooperation of Energy Regulators (ACER), and the European Commission. Work undertaken by Pöyry[15] for the Office of Gas and Electricity Markets (Ofgem) concluded that there was little correlation between instances of low plant margins in GB and in neighbouring systems and no correlation when margins were very low. This supports the contention that interconnector contribution would be high during times of system stress and the need for a more regional approach to resource adequacy assessment, together with the introduction of "market coupling" in both intra-day and balancing timescales. It is also worth noting the conclusions of Booz & Co in their report[16] to the Commission that an EU-wide approach to resource adequacy through increased interconnection would remove the need for some 100 GW of additional generation capacity by 2030, compared with a continuation of the current MS-centric approach.

[10] An estimate of LOLE is given by the overlapping tails of the distributions around central estimates of demand and supply. To simply assume a central (zero) estimate of interconnector flow with no associated distribution makes no sense.
[11] Cox et al., 2012
[12] DECC, 2014
[13] National Grid Interconnector Business, 2014
[14] DECC, 2014
[15] Shakoor & Wilks, 2013
[16] Newbery et al., 2013

To sum up, National Grid's approach to interconnector contribution to capacity a) ignores the impact of market coupling and its extension into intra-day and balancing timescales, and b) assumes that the availability of adequate resources on the other side of interconnection cannot be relied upon and is therefore unsafe to assume any interconnector contribution to security of supply. These concerns, either individually and taken together, are difficult to justify given the available evidence.

Demand Response Resources

In their Capacity Report, National Grid have assumed that a total of 2500 MW of demand-side response (DSR) will be available in winter 2018/19 and the Secretary of State has confirmed that this amount will be "set aside" to be procured in the T-1[17] auction in 2017. This is to be compared with up to 1800 MW of "triad avoidance" demand reduction that occurs regularly each winter and the almost 1000 MW of "expressions of interest" received for the new Demand Side Balancing Reserve (DSBR) service to be implemented this winter. On the assumption that DSR will fully take up the 2500 MW set aside, all triad avoidance demand relief has been removed from the peak demand that underpins National Grid's estimate of capacity to be procured.

It should be noted, however, the term "DSR" covers a number of technologies in addition to demand relief, notably embedded or standby generation. This capacity is not generally visible to National Grid and just how much embedded or standby generation exists in GB, or the capacity likely to participate in the T-4 or T-1 auctions, is unclear. The Expert Panel notes that the peak demand for 2018/19 has been increased substantially on the assumption that this embedded/standby generation will actively take part in the T-4 auction.[18] If it does not, and the peak demand to be met is not adjusted, there will be an over-procurement of capacity. It will be important therefore to address this issue in the pre-qualification period.

Overall, given the known availability of triad avoidance/DSBR capability together with the probable availability of substantial amounts of embedded/standby generation, a higher demand side contribution seems appropriate – particularly given the steps that are being taken to encourage demand side participation over the coming years. There is ample experience in other markets to demonstrate that demand response is capable of delivering as much as 10 percent of all capacity requirements at a far lower cost than new generation and at least as reliably.[19] Furthermore, while embedded/standby generation is able to participate in the T-4 auction, it is not clear why the demand-reduction element of DSR has been excluded. Developing new DSR though aggregation takes time and might involve the development of significant IT and administrative infrastructure. Allowing DSR access to three-year contracts and the T-4 auction would be further encouragement to participation and also "level the playing field" with respect to generation.

2. Undue Distortion of Competition

Overall, National Grid's analysis in the Capacity Report appears ultra-cautious and designed, either intentionally or otherwise, to result in an over procurement of capacity via the T-4 auction to be held this December. When the impact of more reasonable interconnector contribution, generator

[17] The formulation "T-x" used here and following refers to the number of years x ahead of the date of the referenced auction T.
[18] DECC, December 2013
[19] Hurley et al., 2013

availability and DSR/embedded/standby generation assumptions are considered, it is probable that the capacity to be procured could be reduced by at least 5 to 6 GW. This would be more than enough to remove the need to commission new gas-fired generation for the foreseeable future, thereby avoiding the need to award 15-year contracts for what is essentially unnecessary investment in fossil-fired technology. Awarding long-term contracts for new generation will effectively foreclose opportunities for participation by more cost-effective demand response and consequently increase the costs seen by consumers in the long term. As an example, in the PJM auction for the 2012/2013 commitment year, demand response constituted one-third of all resources cleared and resulted in the clearing price being reduced by 90 percent from the expected price of $179/MW-day to $16.46/MW-day.[20] In other words, the extra costs imposed on the UK economy as a result of the current approach could well be very large.

3. Existence of More Appropriate Measure

A Market-wide or Targeted Capacity Mechanism?

DECC initially favoured a strategic reserve rather than a market-wide capacity remuneration mechanism (CRM). Its decision to move away from this option can be challenged, both on need and the detrimental impact on customers.

In their original consultation, DECC indicated that they preferred a targeted CRM rather than the market-wide arrangements now adopted. Their original preference was based on analysis carried out by Redpoint, who concluded that although the risks to security were material, they were uncertain that a market-wide CRM was the most appropriate and cost reflective "insurance policy."[21] This conclusion was reached despite assumptions that clearly favoured a market-wide CRM, such as an assumption that all scarcity pricing would disappear from energy prices.

In their analysis, Redpoint compared "packages" of low-carbon support and security of supply options and demonstrated that the cost implications of low-carbon support outweighed those of security of supply. However, it is clear from their analysis that, for DECC's preferred Contract for Differences (CfD)/Feed-in-Tariff (FiT) low-carbon support option, the costs of a market-wide capacity market are higher than those of a strategic reserve and have a greater impact on consumer bills. This is in spite of the favourable assumptions referred to above. DECC's eventual decision to opt for a market-wide CRM is not therefore supported by the original analysis carried out by their consultants. It is also pertinent to note that the decision to change course followed extensive lobbying by industry.

The choice of a market-wide CRM is also challengeable by reference to the analysis of value of lost load and loss of load probability conducted in the course of the consultation. Without going into the detailed analysis (which can be provided separately) the claim that a market-wide CRM is either warranted or economically efficient may well be fundamentally flawed. The analysis of the value of lost load, while reasonable, leaves open the question of whether the selected standard of 3 hours

[20] Bowring, 2009 (Table 20). "Unconstrained" zones do not experience any distribution or transmission bottlenecks for the delivery of electricity to the end-user, whereas "constrained" zones experience such limitations and pay clearing prices that reflect those constraints to capacity available during peak hours in those zones. Accordingly, the reduction in prices due to demand resources for any individual constrained zone will be higher or lower than $162.32 per MW per day for this auction, depending in part on the quantity of demand-side resources located in that zone.

[21] Redpoint Energy., 2010

should be treated in the administrative mechanism as the mandatory minimum or rather as a target, an issue that was referred to earlier. It is standard practice internationally, indeed it is fundamental to the concept of LOLE, that performance is measured over a series of winters and not a single winter, with margins consciously expected to fluctuate above and, occasionally, below the target. An example of this is the old Central Electricity Generating Board (CEGB) standard that, on average allowed for a supply shortage once every 10 years.

National Grid's analysis, however, points to a standard that is to be regarded as an absolute minimum, rather than a target upon which long-term planning is based. This implies that the capacity procured will be significantly higher than necessary to meet a long-run 3-hour target. This, based on DECC's own analysis, would be an inefficient outcome and the translation of the 3-hour standard into an actual resource margin in practice warrants closer scrutiny. As an example, in the recent and very lengthy proceeding conducted by the Public Utility Commission of Texas (PUCT) regarding resource adequacy, Brattle Group were retained by the PUCT to examine the analytical and practical implications of proceeding with or without the adoption of a capacity market. As part of that proceeding, Brattle analysed:

1) The resource margin that would be efficient given an expert analysis of the value of lost load,
2) The resource margin a properly functioning energy market would actually produce, and
3) The resource margin implied by the Texas standard of 2.4 hours per year (in other words, slightly *more* conservative than the proposed GB standard) based on a conventional statistical analysis of loss of load probability?

The results are particularly instructive for the GB case given that the size of the Electric Reliability Council of Texas (ERCOT) market is very similar to the size of the GB market, the penetration of wind generation in ERCOT is and is expected to be very similar to the GB market, and the ERCOT market is connected to neighbouring markets only by a small quantity of high voltage direct current (HVDC) interconnectors.

Brattle's analysis concluded that the efficient resource margin above peak is 10.2 percent, a properly functioning energy market would deliver a resource margin of 11.1 percent, and the resource margin implied by the Texas standard is 14.5 percent. This points to two possible conclusions in the GB context. First, the target GB resource margin, which is currently pegged at 17 percent,[22] is materially above what it seems one could expect from a proper statistical assessment of resource performance (See above comments regarding the assumed peak season performance of GB resources). Second, the failure of the energy market to deliver even a 14.5 percent resource margin, much less the higher margin apparently being sought under the current proposal, cannot be taken as evidence that the market has failed. It is rather simply the result of a target reserve margin that is beyond what an efficient market outcome would produce.

<u>The point is not necessarily that a 14.5 percent, or even a 16 percent or 20 percent resource margin cannot be justified – that is in the end a political decision – but that there is no theoretical or practical justification for employing a market-wide capacity market to deliver it.</u> The result of doing so would seem inevitably to lead to institutionalised surplus capacity participating in the energy and

---

[22] We have endeavored to use comparable metrics between the two markets; the numbers quoted should both correspond roughly to what in the GB market is referred to as the "de-rated capacity margin."

balancing services markets, permanently suppressing the necessary price signals expected from those markets, and to the imposition of an unnecessary transfer of wealth from consumers to generators in the form of a higher clearing price paid to all generation clearing in the capacity auction. As the Expert Panel stated at page 14 of their December 2013 report, regarding the cost of the CfD instrument, "…higher capacity margins that depress wholesale prices will raise the subsidy required, all other things being equal."[23] For these and other reasons the original recommendation by Redpoint of a target strategic reserve solution, with the assets in the strategic reserve prohibited from participating in the day-to-day energy and balancing services markets, continues to be the most sensible solution for UK electricity consumers.

A Mechanism that Includes Imports

Although DECC recognises the value of allowing non-GB generation to participate in a capacity market, they have, to date, been unable to identify an acceptable model that would allow this to happen. Their primary concerns are that any contracted imports could be swamped by outflows resulting from energy price differentials in a market coupling setting and difficulties in validating the availability and output of non-GB generation.

The outflow concern is not valid. If price differentials cause flows out of GB, then GB would be most unlikely to have a capacity deficit. The existence of a capacity market may exacerbate energy price differentials and increase outflows causing prices to rise higher than would otherwise be the case, but there would not be a capacity deficit. If a GB capacity shortage did exist, energy prices would rise to the point where energy would be imported as described above.

Contracting for non-GB resource, either by allowing interconnectors or external generation to participate directly in the capacity market, would be of most value when a capacity deficit exists at both ends of the interconnector. In this case, energy price differentials may be insufficient to fully utilise interconnector capacity as prices would be very high at both ends of the interconnector. However, as the non-GB generation effectively becomes part of the GB market and the donor system has to replace that generation (if necessary by demand reduction), interconnector flows should be assured. Even in a fully interconnected continental alternating current (AC) system, provided all other MS systems are balanced, the energy should find its way from the donor to the recipient system. In fact, the issue is much simpler for GB, which is interconnected only by dispatchable HVDC circuits.

If, in future capacity auctions, external resource is allowed to participate directly, then it would be inappropriate to discount the total capacity to be procured by some assumed interconnector contribution as this would amount to "double counting." However, as discussed previously, the fact that external resource will not be permitted to participate in the first T-4 auction to be held in December, requires that an appropriate interconnector contribution should be netted off demand to be met.

DECC's concern about validating the availability and output of non-GB generation also seems misplaced. The participation of external resource is accepted practice in capacity markets administered by many U.S. regional transmission system operators such as PJM, New York ISO, etc. In the case of PJM, the requirements to be satisfied by external generation participating in the capacity

---

[23] DECC, December 2013

market, including arrangements for testing and monitoring, are set out in the PJM capacity market manual.[24]

4. Necessity of the CRM

Measures are in train that undermine the need for a market-wide CRM. Ofgem intends radical reform of the GB Balancing Mechanism[25] that appears to undermine the need for market-wide capacity payments. This reform will ensure that cash-out prices reflect the marginal cost of balancing incurred by the TSO, including the cost to consumers of voltage reduction or disconnection. As a capacity deficit situation implies that some market participants will be seriously imbalanced, they could face charges that ultimately reflect the value of lost load (VOLL). Charges of this magnitude will represent a powerful economic signal to procure adequate capacity cover in the form of generation or DSR. Similar measures adopted for the ERCOT market in Texas, including an operating reserve demand curve, were deemed sufficient by the PUCT to obviate the need for or value of a market-wide capacity market.

The introduction of Ofgem's measures will address the principal deficiency in the existing energy market that drives the need for market-wide capacity support, i.e. the fact that energy prices do not reflect the real cost of loss of supply seen by customers. Given these measures, the case for a targeted strategic reserve, designed not to dilute energy prices when capacity is scarce, seems far more appropriate than a market-wide CRM. In fact DECC's proposals seem at odds with Ofgem's Balancing Mechanism reform; the former designed to remove scarcity pricing from energy pricing, while the latter is designed to sharpen energy prices when capacity is scarce.

Conclusions

This policy brief outlines a number of concerns regarding the design of the proposed GB capacity market and, more generally, over DECC's decision to opt for a market-wide CRM rather than a strategic reserve. The authors suggest that, had more appropriate assumptions about generator availability and the contribution to be made by interconnection and DSR, the need to lock into 15-year contracts for new gas generation could be avoided. No planning process is perfect and that is not the standard to which we are proposing the UK government be held. However, we believe that sufficient evidence exists concerning generator availability and DSR and interconnector contribution in situations where capacity is scarce for DECC to reasonably conclude that the need for new fossil generation capacity at this point in time has not been established. <u>Many capacity mechanisms in comparable competitive electricity markets have been designed and successfully executed with much shorter commitment periods – typically no longer than one year – precisely to allow for this type of uncertainty and to avoid undue distortion of competitive markets.</u> No such caution has been shown here. Some of our concerns may turn out to be over-stated, but there are probably many other issues that we have overlooked due to a lack of time. Overall, we believe that DECC have made the wrong choice and that the decision to introduce a market-wide CRM that will commit electricity consumers to underwrite 15-year contracts for capacity, is simply not supported by the available evidence.

[24] PJM Capacity Market Operations, 2014
[25] Ofgem, 2014

References

Bowring, J. (2009). *Analysis of the 2012/2013 RPM Base Residual Auction.* Eagleville, PA: Monitoring Analytics. Available at http://www.monitoringanalytics.com/reports/Presentations/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090910.pdf.

Cox, J., Wilks, M., Hanson, M., and De Carlo, S. (2012). *Impact of EMR on Interconnection: A report to Department of Energy and Climate Change*. Oxford, United Kingdom: Pöyry Management Consulting. Available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/252744/Poyry_Report_on_Impact_of_CM_on_Interconnection.pdf.

Davey, E. (2014, June 27). *Confirmation Of Demand Curve Parameters For The First Capacity Auction*. Available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/324973/20140627_Edward_Davey_to_Nick_Winser_and_Mark_Ripley.pdf.

Department of Energy & Climate Change (DECC). (2014). *EMR Panel of Technical Experts' Final Report on National Grid's Electricity Capacity Report*. Available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/324976/EMR_Panel_s_Final_Report_on_National_Grid_s_ECR.pdf.

Department of Energy & Climate Change (DECC). (July, 2013). *Consultation on the draft Electricity Market Reform Delivery Plan*. London, UK: EMR Delivery Plan Team. Available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/238867/Consultation_on_the_draft_Delivery_Plan__amended_.pdf.

Department of Energy & Climate Change (DECC). (December, 2013). *Annex E: EMR Panel of Technical Experts' Final Report for DECC*. Available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267624/Annex_E_-_PTE_draft_report_FINAL.pdf.

Hurley, D., Peterson, P., and Whited, M. (2013). *Demand Response as a Power System Resource: Program Designs, Performanc,e and Lessons Learned in the United States*. Brussels, Belgium: Regulatory Assistance Project. Available at http://www.raponline.org/document/download/id/6597.

National Grid. (2014). *National Grid EMR Electricity Capacity Report*. Available at http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=34154.

National Grid. (2013). *Winter Consultation 2013/14*. Available at http://www.nationalgrid.com/NR/rdonlyres/D03C2CD6-D81E-4751-AD0A-D4EDF155FE1F/61304/WinterConsultationReport201314FINAL2.pdf.

National Grid Interconnector Business. (2014). *Getting More Connected*. Available at http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=32371.

Newbery, D., Strbac, G., and Noël, P. (2013). *Benefits of an Integrated European Energy Market*. Amsterdam, Netherlands: Booz & Company for Directorate-General Energy, European Commission. Available at http://ec.europa.eu/energy/infrastructure/studies/doc/20130902_energy_integration_benefits.pdf.

Office of Gas and Electricity Markets (Ofgem). (2014). *Electricity Balancing Significant Code Review - Final Policy Decision*. Available at https://www.ofgem.gov.uk/ofgem-publications/87782/electricitybalancingsignificantcodereview-finalpolicydecision.pdf.

PJM Capacity Market Operations. (2014). *PJM Manual 18: PJM Capacity Market*. Available at http://www.pjm.com/~/media/documents/manuals/m18.ashx.

Redpoint Energy. (2010). *Electricity Market Reform Analysis of Policy Options*. Available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42638/1043-emr-analysis-policy-options.pdf.

Shakoor, A., and Wilks, M. (2013). *Analysis of the Correlation of Stress Periods in the Electricity Markets in GB and its Interconnected Systems: A report to Ofgem*. Oxford, United Kingdom: Pöyry Management Consulting. Available at https://www.ofgem.gov.uk/ofgem-publications/75231/poyry-analysis-correlation-tight-periods-electricity-markets-gb-and-its-interconnected-systems.pdf.