Capacity market review: Response to the call for evidence by the Regulatory Assistance Project

Overall, we believe that the introduction of a Capacity Market in Great Britain was a solution to a capacity problem that did not exist at the time. This is evidenced by the auctions held to date being oversubscribed with low auction clearing prices.

At some point, new investment will be required to replace aging and polluting fossil-fuel-fired plants. However, we believe that this investment would best be secured by continuing and accelerating the energy market reform embodied by Ofgem's Electricity Balancing Significant Code Review. In fact, we believe that, by reinforcing the energy market's "missing money" problem, the Capacity Market undermines Ofgem's reforms and could make the need for a Capacity Market self-perpetuating.

We, therefore, believe that the government should clearly state that the Capacity Market is seen as a temporary measure, to be withdrawn once the appropriate energy market conditions have been established. The government should also set out what those conditions are and how they are to be achieved.

In the interim, the Capacity Market should be reformed to improve consistency with the decarbonisation agenda and to support the development of technologies necessary to meet that agenda. This would include moving away from just procuring "vanilla" capacity, recognising the value of flexibility, and removing some of the many barriers to the participation of flexible technologies such as demand-side resources (DSR).

Response to questions

1. Do you believe there is a need to maintain the Capacity Market? What conditions would be necessary for the Capacity Market to be withdrawn?

Looking back over performance of the Capacity Market to date, it is clear that the market was introduced ahead of need. Successive auctions have consistently been oversubscribed, with less new capacity clearing the auction than existing capacity that did not. The low auction clearing prices experienced so far are a consequence of this surplus of capacity.

Looking forward, this situation looks likely to persist, at least for the immediate years ahead. This may change in the longer term, particularly if the decline in peak demand is reversed by the increasing electrification of the heat and transport sectors. However, by that time, the role of smart metering and reform of the energy market brought about by the development of cash-out arrangements and implementation of the European Clean Energy for All package (if still relevant to Great Britain) should be in place. This should allow electricity customers to more fully indicate the value they place on continued supply, thereby incentivising the investment necessary to deliver supply reliability without the need for direct capacity support.

The Regulatory Assistance Project (RAP)®
Belgium · China · Germany · India · United States

Rue de la Science 23
B-1040 Brussels
Belgium
raponline.org

There is however a danger that the Capacity Market will become self-perpetuating. By depressing scarcity pricing, the Capacity Market exacerbates the missing money problem and attenuates the reduction in peak demands that higher peak prices would produce. The reduction in infra-marginal rents and higher demand/capacity requirements brought about by the existence of a Capacity Market both act to reinforce the need for additional capacity support. It is also worth noting that market/cash-out reform and the Capacity Market are clearing pulling in opposite directions. The former attempting to restore missing money to the energy market, while the latter consolidating the missing money problem by depressing infra-marginal rents.

In terms of what circumstances would allow the Capacity Market to be withdrawn, as indicated above, it is not clear that current circumstances justify its existence. However, looking forward, wholesale market reform that allowed prices to reflect scarcity together with retail market reform that allowed customers to respond to those prices seem to be necessary conditions.

2. Do you believe the current objectives of the Capacity Market remain appropriate?

Insofar as the Capacity Market aims to maintain an administered reliability standard at minimum cost to consumers in a fashion that complements the decarbonisation agenda, its objectives seem appropriate. However, although the Capacity Market has been successful in ensuring that the reliability standard is met (not difficult, given the current capacity surplus), it is difficult to claim that the outcome has been to complement the decarbonisation agenda, given the number of open cycle gas turbine (OCGT) and reciprocating plants that have been awarded contracts. And it is difficult to claim that it has done so at minimum cost to consumers, given the persistence of unjustifiable entry barriers to cost-effective demand-side alternatives and the additional payments it provides to generation despite the inescapable conclusion that there is more than enough capacity available to meet a reasonable security-of-supply standard.

Furthermore, as decarbonisation will increasingly place a premium on flexibility, it is difficult to claim that a Capacity Market that focusses on procuring “vanilla” capacity complements the decarbonisation agenda.

3. Do you think the arrangements outlined in section 3.1 are adequate to ensure sufficient capacity is secured through the auctions to deliver security of supply?

See above. To complement the decarbonisation agenda, the Capacity Market should aim to procure flexible capacity, not just capacity. It is insufficient to say that the System Operator has other means of ensuring flexibility—if the energy and balancing services markets that are the best determinants of the value of flexible resources were functioning as intended, an out-of-market capacity mechanism would not be needed in the first place. Not valuing flexibility in the procurement process discriminates in favour of conventional inflexible capacity and against flexible capacity such as storage and

DSR. This implies that we will end up with a plant mix that does not complement the decarbonisation agenda.

Recent reforms to capacity markets operating for many years in parts of the United States, in response to persistent issues with capacity underperformance and overcompensation, have aptly illustrated the evolution the Capacity Market should be expected to undergo. Multiple reforms are in process to improve co-optimisation of demand for energy and services and the resulting energy market scarcity pricing. At the same time, penalties and bonuses under the capacity markets for capacity performance during system stress events have been reformed to eliminate virtually all excuses for nonperformance while placing most or all compensation at risk in the event of nonperformance, conversely tying a substantial share of annual compensation to performance during system stress events, including the earning of bonuses for covering shortfalls from nonperforming resources. These reforms have been adopted with the explicit objective of making compensation for resource investment more closely reflect what those resources would expect to earn in a fully effective energy-only market (more accurately, an energy-plus-services market). See comments to question 7 below.

4. What are your views on the split between the T-4 and T-1 auctions and the amount of set aside?

The ideal split between capacity procured at the T-4 and T-1 auctions should reflect the uncertainties around forecasting demand in those time frames. However, the T-1 auctions are an important entry point for DSR and we believe that there should be a guaranteed minimum capacity set aside in order to give developers confidence. We would certainly council against reducing the T-1 capacity target in response to nondelivery risks as this would further limit the potential for DSR participation.

5. Has the Capacity Market been successful in supporting investment in capacity (new and existing), both directly and indirectly? If not, please identify any changes that need to be made.

While the Capacity Market has been successful in ensuring that the reliability standard can be met, clearly it has not been successful in bringing forward new CCGT capacity. However, given that to date we have not had a capacity problem to solve, this is not entirely surprising.

The Capacity Market has also failed to deliver sufficient DSR participation. While the situation has improved slightly in recent auctions, participation at around 2 percent is low compared to the PJM Reliability Pricing Model or the ISO New England Forward Capacity Market. As demonstrated by the PJM and ISO New England experience, where DSR participation rates are around 10 percent and 16 percent respectively, increased DSR participation offers the potential of significant savings for electricity consumers, and electricity consumers in Great Britain are missing out.

The reasons for this low participation are several and include issues such as minimum offer threshold (2 MW versus the common standard in established capacity markets of

100 kW), delivery assurance, contract length for new capacity, bail bond requirements, and the mechanism for cost recovery from suppliers over the whole of the winter period. Clearly, DSR needs to be treated in a more equitable fashion if participation is to increase and the potential savings for electricity consumers realised.

6. Do the current one-, three-, and 15-year agreement lengths support investment in capacity and do they deliver against the objective of cost-effectiveness?

The availability of 15-year contracts for new generation projects is unnecessary, discriminatory, and distortive.

Unnecessary: Long-standing capacity markets, including those in PJM, ISO New England, and New York ISO (NYISO), have consistently outperformed against their target reserve margins while providing little or no special treatment to new generation; PJM's capacity market has always offered the same one-year commitment periods to both new and existing resources, and in the nearly 15 years of its existence, the PJM market has attracted hundreds of billions of dollars of new investment in supply- and demand-side resources and currently claims a 32.5 percent reserve margin; ISO New England originally offered new resources the option of up to five-year commitments at the auction clearing price, recently extended to eight years (existing resources receive one-year commitments), but few if any of the new resources built in New England have opted for more than one-year commitments due to the low auction clearing prices; nonetheless, ISO New England has consistently maintained a healthy reserve margin over the nearly 15 years its capacity market has been in existence and currently claims a 27.5 percent reserve margin; NYISO has always offered commitments to new and existing resources only one year in advance, and NYISO has likewise long maintained healthy reserve margins and currently claims a 22.5 percent reserve margin.

Discriminatory: It is inarguable that granting 15-year commitments to supply-side bidders while offering only one-year commitments to demand-side bidders creates a bias in favour of investing in supply-side options; the solution isn't to offer demand-side options for the longer commitments, which would be unnecessary, but rather it has been amply demonstrated that matching one-year commitment periods are sufficient, alongside effective energy and services markets, to incentivise needed supply-side investment, meaning there is no reason to continue this discrimination.

Distortive: A legacy of generators enjoying 15-year contracts complicates any effort to withdraw the Capacity Market—assuming that was even the government's intent—and a demonstrated willingness by the government to resort to such pointlessly long commitments long before any new investment is actually needed will lead investors to sit on their hands, anticipating that if they wait long enough the government will do so again.

7. Should penalties be adjusted to strengthen incentives for delivery during stress events? If so, how should penalties be adjusted? Please provide a view on the methodology and factors to consider when setting penalties.

Yes. The fact that penalties cannot exceed annual Capacity Market income provides insufficient incentive to deliver during stress periods. Given that the consequence of nondelivery during a stress event could result in loss of supplies, penalties should be linked to VoLL. It would seem logical if nondelivery penalties were consistent with imbalance penalties.

As noted above, hard-won experience in long-standing capacity markets in the United States has underpinned recent reforms that have removed virtually all excuses for nonperformance and have exposed capacity resources receiving commitments to the full market value of a failure to perform, conversely tying the opportunity to earn capacity market compensation disproportionately to capacity resources' performance during system stress events.

The best of these reforms also ensure that the effects of these bonus-and-penalty arrangements filter through to energy market scarcity pricing. The expressed intent of these reforms has been to make compensation for investment in capacity resources resemble much more closely what such investments would expect to earn in a properly functioning energy-only market (more accurately, an energy-plus-services market). In doing so, the distortive effects of a market designed from the outset to value all capacity as having the same value is moderated somewhat so that those resources able to profit from their ability to be more responsive to the needs of the system will tend to be more competitive in the Capacity Market, whereas those resources least capable of reacting flexibly to system needs will tend to be less competitive. This is the standard that should guide the reform of Capacity Market rules regarding excuse for nonperformance, performance bonuses, and nonperformance penalties.

8. Do the current arrangements relating to credit cover and delivery milestones provide sufficient incentives / assurance that capacity will be delivered, with particular reference to DSR?

The low participation of DSR in the Capacity Market to date suggests that the barriers to entry are already high and that imposing more onerous credit cover and delivery milestone requirements will be counterproductive. Furthermore, as individual Unproven DSR projects are small compared with generation projects, the impact of project failure is reduced, again suggesting that maintaining less onerous requirements for Unproven DSR is justified.

We, therefore, believe that treating technologies such as DSR differently but in a fashion that is appropriate given their characteristics would help establish a level playing field and would not amount to undue discrimination. An example of where the current arrangements hinder the development of DSR is the bid bond, the nature and application of which represent a significant barrier to market entry.

Rue de la Science 23
B-1040 Brussels
Belgium
raponline.org

11. To what extent does the CM design ensure capacity resources are used in the most effective manner during stress events? Do you have any ideas on how it can further be improved?

See responses to questions 3 and 7 above.

The four-hour notice period for the delivery of capacity is an example of how the Capacity Market favours inflexible over flexible capacity. There is real operational value in capacity being able to deliver with less than four hours' notice, yet there is no means within the Capacity Market of rewarding this enhanced flexibility. Incentives to encourage an ability to respond in shorter time scales that reflect the value to the system of doing so should be developed.

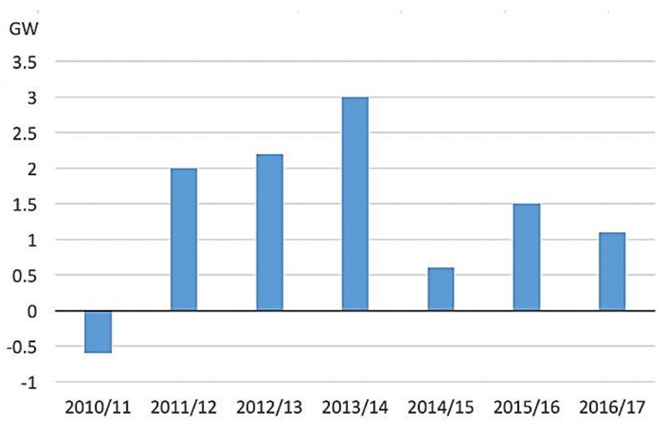
12. Do the de-rating factors correctly recognise the contribution made by different technologies to security of supply? What changes need to be made?

See response to question 11. The current arrangements do not reflect the value that rapid power-shift technologies such as storage bring to the system. To penalise storage for being energy constrained while not rewarding its enhanced flexibility is discriminatory.

13. Do you think there are there sufficient safeguards in place to reduce the risk of over-procurement? If not, what changes could be made to further reduce the risk of over-procurement?

The position of the National Grid Electricity System Operator (NGESO) as the Electricity Market Reform Delivery Body ensures that there is an in-built bias toward overprocurement. National Grid is exposed to the reputational consequences of failure to meet the reliability standard but not the financial consequences of avoiding that failure. This bias is evident in an overcautious approach to demand forecasting, plant availability, and, arguably, scenario selection.

While National Grid's demand forecasting performance is incentivised, a bias to overestimate still exists as shown below.



Peak demand forecasting error (source: Ofgem's 2017 State of the Market Report).

More could also be done to improve plant availability assumptions. As shown below, National Grid's plant availability assumptions are conservative compared with actual availability.

	2016/17 Actual	2017/18 Actual	Capacity market Assumption
Nuclear	6	5	18
Coal	15*	5	12
OCGT	3	3	5
CCGT	7	6	11-13

Assumed generator nonavailability and outturn (%)
Source National Grid publications.

* High unavailability thought to be due to commercial decisions reflecting a low probability of running.

The consequence of this conservative approach is the overprocurement of capacity necessary to meet the reliability standard. In its 2017 State of the Market Report,[1] Ofgem suggest that, in 2016/17, the cumulative expectation of loss of load was 45 minutes, rather than the three hours specified by the reliability standard. While adherence to the reliability standard needs to be measured over a period of years, this, together with the limited number of occasions since 2005 that National Grid has had to apply out-of-market measures, suggests an overprocurement of capacity and the imposition of unnecessary cost on consumers.

15. What further changes are needed to better facilitate the participation of new, innovative or smart technologies, including from DSR, in the Capacity Market?

See response to question 5. The current arrangements whereby the costs of capacity contracts are recovered through the Supplier Obligation on the basis of gross supplier demand during the hours of 16.00 to 19.00 on every working day during the period November to February, significantly devalues DSR. Few potential flexibility providers are able to countenance demand reduction on every working day over this extended period.

The application of charges via a Triad-based methodology or some other methodology that limited the number of charging demand periods would make DSR participation in the Capacity Market considerably more attractive and would reduce the amount of capacity to be procured.

See response to question 11. Some means of recognising the value that fast response storage and DSR can bring to the system would encourage greater participation.

[1] Office of Gas and Electricity Markets (Ofgem). 2017. *State of the energy market 2017 report.* Retrieved from: https://www.ofgem.gov.uk/system/files/docs/2017/10/state_of_the_market_report_2017_web_1.pdf

18. What are the main distortions in competition that need to be addressed to ensure a level playing field in the CM auctions?

The Capacity Market is inherently discriminatory in that it is built around the characteristics and requirements of a conventional plant. Measures to address this mentioned previously could include:

- Applying a consistent approach to contract length
- Applying a more equitable approach to credit cover and bid bonds that recognised these present a particular hurdle to DSR and smaller projects
- Modifying the Supplier Obligation cost recovery mechanism to reduce the number of charging periods, thereby removing a particular barrier to entry for DSR projects

20. How could the Capacity Market better complement the decarbonisation agenda, whilst still ensuring technology neutrality?

See response to question 2. Decarbonisation will drive the value of flexibility. If the government really wants the Capacity Market to better compliment the decarbonisation agenda, it would need to adopt arrangements that value flexibility.

Furthermore, market reform that ensures energy prices reflect the value of continued supply, i.e., scarcity pricing, will encourage flexibility and complement the decarbonisation agenda. To the extent that the Capacity Market replaces the missing money that should be routed through the energy market via infra-marginal rents, it is detrimental to flexibility and the decarbonisation agenda.

21. Should wind and solar be allowed to participate in the Capacity Market? Why?

Yes. Wind, solar, and hybrid renewables projects not in receipt of other subsidies should be allowed to participate in the Capacity Market as is the case in many other jurisdictions. In fact, this is a legal requirement of European legislation.

Participation would require an objective analysis of what contribution each technology can make, and this would need to take account of the advantages of aggregation and geographic diversity.

25. For co-located projects, do you think that all components of the site (both the CM eligible and the non-CM) will be able provide their full capacity during the system stress event due to local distribution or transmission network constraints?

The transmission system in Great Britain is designed to ensure that transmission constraints should not impose a restriction of more than 5 percent on generation availability over peak. This suggests that the impact of transmission constraints can more or less be ignored.

26. What lessons can be learnt from the participation of renewables in other overseas capacity markets?

It is pertinent to note that most if not all transmission system operators (TSOs) will take some account of the ability of wind to contribute to meeting peak demand in their resource adequacy assessment; National Grid certainly does. This suggests that wind could contribute successfully to the Capacity Market.

27. Is the current de-rating factor methodology for interconnectors appropriate for assessing their contribution to security of supply? Are there any particular challenges or risks you wish to highlight?

Our understanding is that the derivation of interconnector derating factors is based on a combination of historic flow and price-differential analysis and forward-looking simulation. This seems a reasonable approach to a difficult issue as historic analysis alone may not capture the impact of infrequent stress events or of changes in market design. However, as the simulation involves an analysis of the characteristics of neighbouring systems and assumptions regarding stress events that extend beyond our borders, we would like to see a more regional or collective approach to the problem of establishing reasonable assumptions about interconnector contribution. A regional approach, in which TSOs collaborated and used agreed stress-event scenarios, would seem to offer the prospect of more consistent and reliable outcomes.

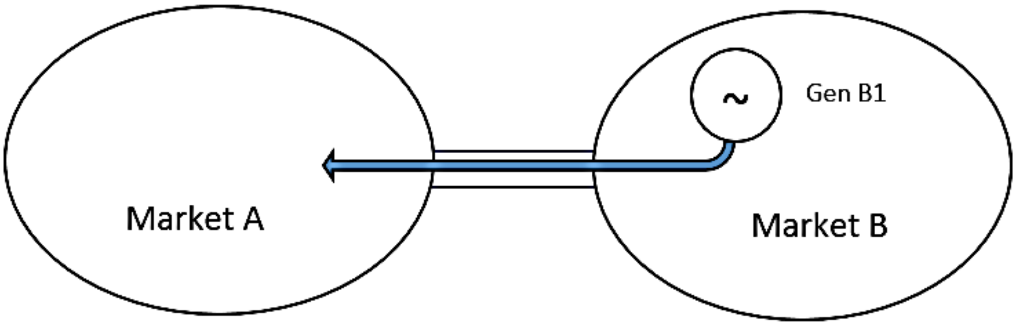
28. What other factors need to be considered to ensure that interconnectors and domestic capacity providers compete on a level playing field? Please provide ideas on how any issues you have identified can be addressed.

An obvious issue is that interconnectors are exempt from transmission network use of system and balancing use of system charges, which are paid by domestic generators. Generators situated in continental Europe generally pay little or no transmission charges and therefore are at a competitive advantage to domestic generators in terms of participating in the Capacity Market, either directly or indirectly. It is not clear how this issue can be addressed, other than by adopting a more harmonised approach to transmission charging across Europe.

29. How could we facilitate direct participation of overseas capacity in the future?

Facilitating the direct participation of nondomestic generation in the Capacity Market is likely to be a complex process. In addition to the need to restrict total external resource participation to take account of interconnector capacity and address issues of monitoring nondomestic sites, enhanced data exchange and TSO cooperation will be required.

In attempting to understand the issues involved, it is helpful to consider what the participation of nondomestic generation in the Capacity Market is really attempting to achieve. Essentially, the objective is to allow access to the most cost-effective resources and to maximise the contribution of interconnection in situations where capacity is scarce, particularly when that scarcity extends to the electricity markets at both ends of the interconnection. In order to illustrate how this may be achieved, it is instructive to consider the simple example shown below of two interconnected markets, A and B.



Imagine that a generator located in Market B, generator B1, is awarded a capacity contract in the Capacity Market of Market A. The following paragraphs investigate how this arrangement might operate when scarcity occurs in Market A only and when scarcity extends to both markets.

Scarcity Occurs in Market A

In this case, generator B1 would bid into the Market B day-ahead energy auction in the normal fashion. The Market A and Market B generation and demand curves would be effectively combined, and assuming sufficient interconnection capacity was available and ignoring the impact of any price caps, the market coupling process would schedule sufficient generation capacity to meet the combined Market A and Market B demand. A single clearing price across both markets would emerge, and if generator B1 cleared the energy auction, it would be scheduled to run. If it did not clear the auction, it would not run.

In this case, the scarcity event in Market A would be dealt with by the day-ahead market coupling process. Generator B1 would either operate and contribute to meeting the combined Market A and Market B demand, or its output would be displaced by lower-cost Market B generation. In the latter case, the capacity contract between Market A and generator B1 could be considered as an unused insurance policy. It should be noted, however, that, as generator B1 was available to provide capacity in the scarcity situation irrespective of whether it cleared the day-ahead auction or not, it is necessary that capacity payments be made based on availability and not energy delivered.

The above assumes that the interconnection capacity between Market A and Market B is sufficient to fully accommodate the export from Market B necessary to meet Market A demand—in other words, the interconnector was unconstrained. If this is not the case, the Market A and Market B clearing prices will diverge, with the price in Market A rising above that in Market B. Generator B1 may or may not clear the Market B auction in these circumstances. However, this is immaterial as the interconnection between Market A and Market B will be fully utilised and no more can be done to support Market A demand. Again, in the event of generator B1 not clearing the Market B auction, the contract between generator B1 and Market A can be considered as an unused insurance policy, and provided generator B1 was available to generate, it should be entitled to capacity payments.

Scarcity Extends Across Both Market A and Market B

As before, generator B1 would bid into the Market B day-ahead energy auction in the normal fashion. Again, the Market A and B supply curves would effectively be combined and would attempt to satisfy the total Market A and B demand. Ignoring the impact of any price caps, the clearing price in both markets would rise to reflect scarcity, but any price differential that occurred may be insufficient to fully utilise available interconnector capacity.

Again, assuming that interconnector capacity remains unconstrained and that generator B1 clears the combined auction (as it would do if insufficient capacity was available to meet either the combined or individual Market A and B demand), then it would be scheduled to run. However, as it would be contracted to provide capacity to Market A, it would need to be replaced in Market B by additional resources. If no additional resources were available in Market B, generator B1's output would need to be replaced by an equivalent amount of demand disconnection.

This particular situation—scarcity affecting both markets and the interconnection between the two remaining underutilised—is where capacity contracts with external nondomestic generation would be useful. In other situations where scarcity is restricted to one market, then market coupling should do the job either with or without the need for the contracted generation to run. However, when scarcity exists across markets, capacity contracts will effectively define where any necessary demand disconnection takes place. This implies that generation participating in a neighbouring Capacity Markets results in the virtual relocation of that generation from the market in which it is located to the market to which it is contracted. The donor system operator will need to respond to that virtual relocation by discounting the output from its energy balancing systems and replacing that energy, either by additional generation capacity or, if none is available, by demand reduction.

In these circumstances, the recipient market or member state needs to have confidence that the TSO in the donor market would indeed discount the output from any contracted generation from its balancing activities and maintain an energy balance by disconnecting domestic consumers. Currently, we are far from this desired position as most, if not all, member state procedures for dealing with supply reliability will curtail interconnection exports before initiating domestic demand disconnection.

Does Generation Contracted to a Neighbouring Capacity Market Need to Reserve Interconnector Capacity in Advance?

Parties wishing to engage in cross-border trade have the opportunity to hedge any potential energy market price differentials on the day by reserving interconnector capacity in advance, i.e., by purchasing physical or financial transmission rights. At first sight, it would therefore seem appropriate that nondomestic generation wishing to participate in a neighbouring CRM should do the same. Indeed, this is a requirement in some other jurisdictions, e.g., the U.S., where external capacity trades take place.[2]

However, reserving interconnector capacity in advance so that external generation could contribute to resolving scarcity situations would reduce that available for day-ahead and intra-day trading. This would be undesirable and is in fact unnecessary—if the premise is accepted that the purpose of contracting with nondomestic generation is only to ensure that interconnection utilisation is maximised when scarcity exists. From the above, it can be seen that capacity contracts only come into play if market coupling cannot deliver the energy necessary to fully utilise interconnector capacity, i.e., the interconnector is unconstrained. The value of interconnector capacity when it is unconstrained is effectively zero, and therefore there is no case to impose any charges on generation utilising capacity that would otherwise remain unused.

Another way of looking at this issue is to recognise that the purpose of reserving interconnection capacity in advance is to gain access to higher energy prices in an adjacent market. As nondomestic capacity participating in a Capacity Market would only ever be able access energy prices in its home market (noting that where interconnection capacity is not fully utilised, energy prices in coupled markets would be the same), there is again no case for requiring that generation reserve interconnection capacity in advance.

[2] International Energy Agency (IEA). (2014). *Seamless power markets: Regional integration of electricity markets in IEA member countries*. Retrieved from https://www.iea.org/publications/freepublications/publication/SEAMLESSPOWERMARKETS.pdf