



Participation of interconnected capacity in the GB capacity market

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Executive summary

The UK Government has decided to introduce a market-wide capacity market (CM) to the Great Britain (GB) electricity system. The Capacity Market works by giving all capacity providers a steady payment to ensure enough capacity is in place to meet demand.

The first auction for capacity agreements is expected to take place in December 2014. Only domestic capacity, whether that is generation or demand side response, is able to participate in that first auction. However, the Department of Energy and Climate Change (DECC) have expressed a desire to open future auctions to interconnected capacity, by allowing either interconnectors or generators located outside of the GB market to participate directly. The rationale for their inclusion in future auctions is, in particular, based on ensuring that incentives for additional investment are not distorted in favour of GB generation at the expense of (potentially more efficient) interconnection to European markets.

DECC asked Frontier Economics to support them in considering the options for enabling interconnected capacity to participate in the GB capacity market. Following a review of international experience, we developed a set of options for the inclusion of interconnected capacity and then assessed these options against an agreed set of criteria in order to develop policy recommendations.

Option definition

First, we developed options in which the interconnector owner is the participant in the GB capacity mechanism. These options vary according to a number of building blocks:

- the obligation taken on by interconnector owners who clear in the auction – we consider options in which there is *no obligation*, and options in which the obligation is simply to be *available* or to *deliver energy at times of GB system stress*; and
- what the interconnector owner does with the obligation – we consider options in which they *continue to hold the obligation* or *pass it on to others* (e.g. *interconnected generators*) *who may have (even marginally) more influence on flow*.

We then developed options in which owners of interconnected generation capacity are the participants. These options vary according to further building blocks:

- the obligation taken on by generation owners which clear in the auction – we consider options in which the obligation is for the generator simply to be *available* or to *deliver energy at times of GB system stress* in

addition to whether the interconnector must also be available or deliver energy at times of GB system stress;

- whether *all generators in the internal electricity market (IEM)* can bid (i.e. assuming a copper plate network throughout the EU), or whether bidding is restricted to *those deemed capable of flowing power to GB* (i.e. derating plant based on their likely contribution to GB system adequacy); and
- whether participation is through an *implicit* or *explicit* auction of the right to participate in the CM (limiting aggregate participation to the derated interconnector capacity).

Availability can be further defined in two ways in an international context. It can be defined as simply *submitting a bid into a relevant non-GB market* (as is the case in some US markets) or as *generating into the non-GB market*. Similarly, delivery can be defined as *energy flowing into GB with the interconnected generator generating only if called to fulfil a bid into a non-GB market*, or as *energy flowing into GB and the non-GB generator generating*. We considered all of these options.

For all the options, we then considered three further issues.

First, we considered the way in which the risk of two countries experiencing a stress event simultaneously should be taken into account. We argue that if two interconnected countries are experiencing stress conditions, generation capacity in one country is unlikely to be able to contribute to security of supply in the other. **Therefore we recommend that interconnected capacity should be derated to reflect:**

- **expected physical availability (as with domestic generation); and**
- **the likelihood of coincident stress (with higher probability resulting in higher derating).**

Second, we considered contract length. We noted that interconnected capacity could be treated as domestic capacity in the CM, with contract duration depending on capital expenditure. However, within a fixed 15 year contract, it may not be possible to vary the volume associated with the interconnector (e.g. in response to a perceived change in the probability of coincident stress). Although this issue also occurs in the case of domestic generators with a 15 year contract, it may be exacerbated for interconnectors because the level of secure capacity could be affected by the extent of European Target Model (ETM) implementation and market outcomes. We also noted that longer term contracts may be less critical than for domestic generation, depending on the incentives and insurance provided by the broader regulatory framework for interconnector investment. **We therefore conclude that there may be a rationale for limiting the award of longer term contracts for interconnected capacity.**

Third, we noted that for all the options, there may be a perceived risk that imperfections in markets result in power not flowing to GB in stress conditions.

We noted that following the implementation of the ETM for electricity markets, imports to GB could be facilitated both through continuously traded coupled intraday markets and shared balancing arrangements. We noted that to ensure electricity flows to the higher priced market, there is not a need for particularly deep and liquid intra-day markets. Rather, there simply needs to be a platform which will provide enough of a signal to generators in interconnected markets of GB generators', retailers' and traders' high demand for (and high valuation of) additional volumes. Similarly, we noted that TSOs would, via bilateral sharing of bid-offer ladders, be able to address any under-utilisation of interconnector capacity in a stress event.

Under the ETM model, failure of the interconnector to flow towards a market in stress with higher prices would therefore represent a significant market and institutional failure. Prior to ETM implementation, the risk may be greater. **We conclude that the timing of the implementation of the ETM may therefore have implications for the most appropriate option to pursue.**

Assessment

We assessed each of the building block choices against six criteria:

- *efficiency*: does the option avoid reduced incentives for investment in interconnection relative to generation, and avoid distortions to short-run despatch?
- *security of supply*: does the option ensure sufficient capacity is available in a stress event?
- *cost to GB customers*: is the cost of ensuring security of supply increased or decreased for GB consumers?
- *equity*: is non-GB and GB capacity treated fairly?
- *deliverability*: how complex is the option to implement?
- *consistency with the EC*: would the option raise potential concerns with the EC regarding the implementation of the ETM and state aid guidelines?

Availability vs. delivery models

Models where the obligation relates to availability (rather than delivery) may lead to investment inefficiencies. In an availability model the interconnector (or generators) is not exposed to the risk that power does not flow into GB during the stress event. Under these models, the delivery risk is transferred to GB consumers for interconnected capacity but not for domestic generation. Therefore, exempting it from penalties may represent an implicit subsidy. This could distort investment decisions.

At the margin, there is the potential for investment inefficiencies to be mitigated through regulation. Given Ofgem's cap and floor regime, the regulator may be able to account for the potential to over-invest in the cost-benefit analysis of whether the interconnector should be granted regulated cap and floor revenues. As long as the marginal investment in interconnection is regulated, some control over the total amount of new investment should be possible, and the regulator could choose to correct for any investment distortions.

Models where the obligation relates to delivery may have a greater potential to lead to despatch inefficiencies, the impact of which will largely fall in the foreign market. These are likely to be small and infrequent distortions given the expected infrequency of stress events, and can potentially be mitigated through the design of the obligation. Distortions could arise if the incentives from the delivery obligation result in generators generating out of (non-GB market) least cost order during a stress event (in order to avoid penalties). This distortion is most likely to occur when the CM obligation requires the generators to generate, with the likelihood being reduced if generators are only required to bid. An availability model where generators don't have to generate (i.e. when the requirement is that the interconnector is available and generators just bid) is likely to have the lowest risk of distortion. For all the options there may still be small distortions related to testing.

Notwithstanding this small risk of distortion, if there is a risk that markets are not sufficiently efficient to ensure delivery of power to GB in a stress event (e.g. because the ETM has not yet been completed), delivery models can deliver enhanced security of supply. This is because they can incentivise generators (directly in a generator model or indirectly in an interconnector option where the interconnector backs off its obligations) to help the interconnector flow into GB. In a scenario in which there is spare capacity on the interconnector during a stress event, an availability model does not improve the probability that the interconnector will be flowing into GB.

There are also some relevant considerations in relation to consistency with EC developments:

- there is a question as to whether a penalty payment related to the non-flow of an interconnector would be viewed by the EC as compatible with the Third Package;
- the EC has also highlighted a preference for not undermining the operation of the IEM, including market coupling, so an option which increases the likelihood of distortions, albeit small and infrequent ones, are more likely to be interpreted as having a negative impact; and
- there is potentially an emerging trend within Europe towards availability models.

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The case for a delivery based model diminishes as the ETM is implemented and its efficiency is proven. However, the date of implementation of the ETM is uncertain. If the ETM were to be delivered to schedule in 2019-20, an availability model might be appropriate in the 2015 auction. Since there remains uncertainty surrounding the delivery timing, there may be merit in persisting with a delivery model until certain agreed milestones in ETM implementation are met.

Generator vs. interconnector participation models

Both interconnector owner participation and generator owner participation options allow payments to flow to the interconnector owner to support efficient investment in interconnectors. The signal is more direct for the interconnector options, and there may be fewer gaming risks (e.g. to the extent that there is a specific concern about generator market power in an interconnected market, interconnector options remove their direct participation).

However, within a delivery model, allowing interconnector owners to participate may weaken incentives to ensure power flows to GB. If the probability of a stress event in any given year is low, and the penalties for non-delivery are not sufficiently sharp (or regulation dampens their impact), the interconnector owner may choose to hold the delivery obligation themselves (rather than pass it on to non-GB generators). This would negate the intended security of supply benefits of a delivery model, as the interconnector is likely to be less able than non-GB generators to influence flows.

Interconnector options are simpler to administer. Generator options create more non-GB parties bidding into the auction and sites to verify, and require co-operation with the neighbouring TSOs on measurement and verification of bidding or generation. However, to the extent that there appears to be an emerging trend in Europe towards generator models, implementation of an interconnector model may avoid cost now but lead to further cost of change in the future.

The choice between interconnector and generator obligations is finely balanced. The choice will depend on the relative weight placed on the assessment criteria – we do not provide a recommendation either way.

Location of participating generators

Location is not an issue under models with interconnector owner participation. For generator participation models, assuming a ‘copper plate’ network (i.e. allowing participation from anywhere within the IEM) could improve competition from foreign capacity, mitigating concerns about market power and gaming. However, security of supply is likely to be affected by allowing the participation of generators where there is no reasonable chance that they can influence the flow over the interconnectors into GB. Further, the EC State Aid guidelines are unlikely to support participation of all plant in the IEM. They state

that a capacity remuneration mechanism (CRM) should allow any capacity which can effectively contribute to generation adequacy to participate.

De-rating each generator on the basis of its specific location would require a complex calculation, and inevitably it will not be possible to perfectly de-rate each generator. However, a methodology could be developed to ensure bids are only made from plant in regions with a relatively high probability of delivering power in a stress event.

We recommend that generation be derated according to their likely contribution to GB security of supply. For many generators in the IEM, this may imply a zero derating factor.

Explicit vs. implicit auctions

In theory, both an implicit and explicit auction could lead to the same allocation of revenues between the generators and the interconnector. However, as with market coupling in the energy market, in generator participation models there are reasons to believe that an implicit auction will reduce the risks to participants and hence improve efficiency. This is because under explicit auctions, there may be a delay between generators buying a right to participate in the CM and then the price of capacity being established. Some forms of explicit auction may be able to achieve similar benefits.

While an implicit auction would need to be designed and implemented centrally, adding complexity and potentially delaying implementation, some degree of co-ordination might also be required were a separate explicit auction to be implemented for each interconnector.

We recommend an implicit auction, as it is likely to be more efficient and equitable than a pure explicit auction, and seems more likely to be consistent with the future direction of the EC.

1 Introduction

The UK Government has decided to introduce a market-wide capacity market (CM) to the Great Britain (GB) electricity system. The Capacity Market works by giving all capacity providers a steady payment to ensure enough capacity is in place to meet demand.

This has been put in place to address investor concerns about ‘missing money’ weakening the incentive to invest in conventional thermal generation. As the sector decarbonises, thermal plant will face increasing uncertainty about running hours, making them more reliant on very high prices during periods of scarcity to recover their fixed costs. Investors may find these prices difficult to predict, and may be fearful that they trigger regulatory intervention. As a result of this increased uncertainty, an energy-only market may no longer incentivise sufficient capacity to meet demand.

The first auction for capacity agreements is expected to take place in December 2014. Only domestic capacity, whether that is generation or demand side response, is able to participate in that first auction. However, the Department of Energy and Climate Change (DECC) have expressed a desire to open future auctions to interconnected capacity, by allowing either interconnectors or generators located outside of the GB market to participate directly.

The rationale for their inclusion in future auctions is, in particular, based on ensuring that incentives for additional investment are not distorted in favour of GB generation (potentially at the expense of more efficient interconnection to European markets). Even if it were cheaper to meet the Reliability Standard by developing more interconnection capacity, investors may choose to develop new local power plants instead. This is because of the additional investment incentive provided to domestic capacity by the CM over and above that provided by the energy price.

The potential distortion to investment would be greatest if interconnectors were developed on a purely merchant basis, since profits will be lower as a result of their exclusion from the CM. However, even in the case of the cap and floor regime under development by Ofgem, where a developer is guaranteed a return within a certain range, their exclusion could have a similar effect. It may reduce the likelihood that proposals for new regulated investments in interconnection have a positive business case when being considered by the regulator. .

Further, including interconnected capacity can also increase the number of participants in the CM auction, thereby increasing competition and bringing benefits for GB consumers.

The exact form that participation of interconnected capacity could take is a complex question which has not been tackled before in the GB context. Whilst

there are examples internationally of capacity markets that include interconnected capacity, none have done so with a market structure similar to that of GB.

DECC has asked Frontier Economics to support them in considering the options for enabling interconnected capacity to participate in the GB capacity market. In doing so we have developed a set of options for participation and assessed them against a set of criteria agreed with DECC. The criteria capture the main categories of societal costs and benefits, the practicality of the option for DECC and delivery institutions, and the consistency with EC policy now and in the future.

We have sought to develop a set of options which are consistent with the basic framework of the proposed CM design in GB i.e. we have not sought to propose options which fundamentally apply a different model or approach to interconnected capacity. For example, our options do not consider financial reliability options, or allow interconnected capacity to choose their own de-rating. Both of these features have been considered and rejected as part of the main CM design.

This process is aimed at assisting DECC in implementing an option in time for auctions in 2015.

We have structured the report as follows:

- **Section 2** provides a summary of the international review of capacity mechanisms to understand the range of options deployed for the treatment of interconnected capacity elsewhere.
- **Section 3** sets out the options for consideration in GB.
- **Section 4** sets out the criteria for assessment discussed with DECC.
- **Section 5** assesses the options and provides a clear analysis of the trade-offs.
- **Section 6** sets out our policy recommendations.

Frontier Economics has worked on this issue before, publishing previous analysis on behalf of Energy Norway. This paper builds on that analysis by applying the same analytical framework to the assessment of the options. However, our findings, whilst consistent across both reports, cannot be directly compared. First, for DECC we have considered a broader and more detailed set of options. And second, our thinking has been guided by new developments in the fast changing regulatory and policy backdrop.

For example, as mentioned already, Ofgem has recently announced their decision to roll out a cap and floor regulatory regime for near-term¹ electricity interconnectors and opened an initial window for cap and floor applications. Under the regime, eligible projects that are assessed to be in the interests of consumers would be granted regulated cap and floor revenues. This has been important for considering the impact of the different options presented on interconnector investment. Further, discussions in Europe have progressed. The European Commission (EC) has published its final version of the Guidelines on Environmental and Energy Aid for 2014-2020; and more detail has emerged regarding design proposals for capacity remuneration mechanisms (CRMs) in other countries, in particular France. This has been important for understanding the legality of the options and consistency with the likely direction of policy in other European markets and across Europe as a whole.

¹ Projects which meet a proposed set of eligibility criteria, including a connection date before the end of 2020.

2 International review

We conducted a review of international CRMs in order to understand if there were any examples of international best practice which could help inform the development of options.

This review focused on the different approaches taken in markets in Europe and the US. Some valuable insights were made during the study. However, it was clear that a workable option could not be imported directly from an existing international example. There are two main reasons for this:

- First, many European markets that we reviewed do not include interconnected capacity in the capacity market. Therefore, the level of relevant learning is low. Interconnector users are included in the Irish and Russian schemes. However neither of these examples are directly applicable to the GB system.
- Second, we need to consider carefully the applicability of lessons from US markets where interconnected capacity is included and the availability of information is high, not least because the US approach to coupling markets is very different.

The individual market reviews, and an outline of our approach to the review is contained in Annex 1.

2.1 US markets

In the US we reviewed the three markets of New England, New York and PJM, all of which allow the participation of interconnected capacity in neighbouring states.

New England and PJM started their capacity auctions in 2008 and 2007 respectively, both for the same delivery year of 2010/11. New York started in 2000 with delivery 6 months later in the following season.

There is a significant amount of information available for each of these markets. However before reviewing it in any detail it is important to understand how US markets operate differently to those in Europe. In particular, the way markets are coupled in the US differs from the approach that will increasingly be used in Europe. As a result, the model for integrating interconnected capacity in the US is less relevant in the GB context.

Generators in the US can trade on a particular market's power exchange from outside of that market, delivering power over an interconnector using physical transmission rights (PTRs). This enables interconnected generators to demonstrate that they have a commercial path to deliver power to the market

where they hold a capacity obligation. Although this still does not guarantee that the power will always flow into the market e.g. due to larger nominated flows in the opposite direction, this model does allow power to be tagged to an individual generator, aiding verification of delivery.

The movement towards market coupling prevents this in Europe. The market coupling algorithm is responsible for scheduling flows over the interconnectors. The result is that it is not possible to identify whether an individual generator has supplied the market in stress.

Each of the three US markets reviewed are similar in their treatment of external capacity. They all allow external generators to bid into their capacity market, with the value flowing through to the interconnector owners from the sale of PTRs. Interconnectors and external demand side response (DSR) are not eligible to participate.

Because the markets are not coupled by implicit auctions for interconnector capacity, a generator is able to make themselves exclusively available to a particular capacity market, even if physically located outside of that market. Having contracted with a neighbouring market, the capacity cannot bid into, or be considered part of the market in which it is physically located. And therefore, that market does not consider them to be present in their own capacity calculations.

To be eligible to bid into a neighbouring capacity auction, generators must have a commercial contract for a PTR for at least the duration of the contract of the capacity agreement. In addition they are required to bid into the energy market every hour, usually below a price cap. This is therefore an example of an availability based model, where penalties are levied if they do not bid in a particular hour. There is no commitment to deliver actual energy from either domestic generators or imports. The requirement to bid into the market in each hour, is a very different obligation to GB where the definition for ‘delivered energy’ is based on delivery during a stress event.

The total quantity of bids tends to be restricted to the capacity of the interconnector, which is de-rated for technical reasons and in some cases for tie-benefits as well. Tie-benefits represent the amount of emergency assistance (i.e. balancing resources) that is assumed to be available from neighbouring control areas in the event of a capacity shortage, without jeopardising their reliability.

A concern in Europe is the risk of the interconnector not flowing into the market during a period of market stress. In the US this is less of a concern since generators are exclusively linked to one market by virtue of their capacity agreement. If the interconnector does happen to be exporting during a period of stress, then this would be the net result of contracted capacity imports and exports. The net export would have been reduced by the generation from the generator in the neighbouring market with a capacity contract.

International review

A very high-level summary of the US markets that we reviewed is set out in **Table 1**.

Table 1. Summary of participation of interconnected capacity in US capacity markets

Summary	
Who participates in the capacity market?	Across all three markets reviewed it is the generators in the interconnected markets that participate, and not the interconnector. External DSR is excluded.
How is import capacity rationed?	Total imported capacity contracts are limited to the de-rated level of the interconnector capacity.
Can parties bid into more than one market?	Generators need to demonstrate that they are not available for any other market e.g. using a letter proving non-recall by another market, and must demonstrate a commercial contract for a PTR covering the period of the capacity agreement.
How are imports over the interconnector de-rated?	Physical capacity on the line is de-rated for technical reasons, and in some cases for the tie-benefits or system stability reasons caused by outages. Market reasons, such as a coincident stress event in a neighbouring market do not lead to a further de-rating, in part because generators can only bid into one market.
How is delivery ensured?	Delivery is ensured by generators making themselves available to the market. This is by bidding into the market for every hour at a reasonable price and obtaining a physical transmission right.
What is the penalty regime?	Penalty schemes are based on non-availability. This means that they are penalised if they do not offer power on the power exchange for a given hour. Penalties increase depending on the shortage situation in the market, but are not tied to a particular stress event.

Source: Frontier Economics

2.2 European Markets

There is currently no European capacity market where interconnected capacity has been allowed to participate in a way relevant to GB:

- The Irish market makes a capacity payment on availability for users of the interconnectors. However, this model is not compatible with the European Target Model (ETM) and will need to change in future.

- The Spanish do not make capacity payments to interconnected capacity, and the French have yet to determine how interconnected capacity can be included (although they have set out their initial thinking on potential options).
- Russia does in theory allow the participation of Finnish generation in their capacity market. However, this is currently impossible due to technical differences between the two markets.

3 Option development

This section develops practical options for the inclusion of interconnected capacity into the GB CM. In developing these options, we have considered two related but distinct issues.

- First, a key concern for the countries procuring capacity through a CRM will be the extent to which they can rely on interconnected capacity to deliver power during a market stress event². We discuss potential reasons why power may not always flow to the market in stress, and suggest how energy market arrangements can be designed to help ‘secure the flow’ of power. These considerations cut across all the options presented in this report.
- Second, we turn to the practical considerations of how to enable the interconnected capacity to participate in the GB capacity market. We consider the key ‘building blocks’ which make up a range of alternative models for consideration by DECC.

3.1 Securing the flow

Electricity is a homogeneous product, so there is no difference in the power delivered to the consumer by an interconnector or a domestic generator. Interconnectors are historically physically reliable (at least to the same level as a domestic generator)³. And, even if this were not the case, the interconnector’s capacity allowed to be bid into the CM auction could be adjusted for reliability. In the proposed design of the GB CM, the amount of capacity each generator is allowed to bid into the CM auction is adjusted for its physical reliability based on historic data.

However, there are two further potential areas of concern. First, shocks may occur coincidentally in the balancing zones at either end of the interconnector, and second, markets may not be perfect and so power may not flow to the market with the highest price (which should be the market with the greatest degree of ‘stress’).

² In GB, a market stress event is defined as a settlement period in which either voltage control or controlled load shedding are experienced at any point on the system for 15 minutes or longer. The System Operator will issue a ‘Capacity Market warning’ at least four hours in advance of any anticipated stress event.

³ National Grid’s performance report for IFA (the interconnector between France and England) has availability levels consistently above 90%.

3.1.1 Coincident stress events

If the markets on either end of the interconnector are experiencing scarcity, then it is not certain in which direction the power will flow. In theory prices should rise in each market with power ultimately flowing towards the market willing to pay more for power instead of experiencing demand reduction (i.e. the market with the greatest degree of scarcity or the higher value of lost load, VoLL). However, the market may not operate in this way without an active demand-side, where VoLL is set administratively. There could be a range of outcomes which will be difficult to predict. For example, power may flow to the market with the higher price cap, or TSOs may intervene to control the flow.

The design of the CM will need to take into account the potential for such coincident stress events, which is likely to differ depending on the neighbouring market. Although this risk is likely to be low⁴, accounting for this risk will be important for allaying policymakers' concerns.

We described above that generators bidding into the capacity mechanism are only able to bid up to a de-rated capacity limit. This de-rating reflects the historic reliability of the generator and hence the likelihood that it will be available to supply power at peak. In the same way, the interconnector should be de-rated to reflect its physical reliability. However, it should also arguably be de-rated further to reflect the risk that it may not flow due to coincident stress events.

In thinking about how this might be achieved, it is helpful to consider three scenarios:

- *Zero probability of coincident stress events* – in this (hypothetical) scenario, stress events never occur in neighbouring markets at the same time. In this situation, the de-rating of the interconnector capacity should only take account of the historic physical reliability of the cable. This is because the interconnected capacity can act as a resource in CMs for both neighbouring markets without any risk of conflicting demands.
- *100% probability of coincident stress events* – in this (equally hypothetical) scenario, stress events in neighbouring markets always occur together, meaning that there is no reliable capacity that an interconnector can provide. There is no value in allowing an interconnector to bid into the CM and given the flow of the interconnector will be difficult to predict ex ante, it should be assumed that the interconnector is at float (neither importing nor exporting) when calculating how much capacity should be bought in the CM auction.

⁴ The risk of any stress event is expected to be low and so the risk that they coincide in both markets will also be low.

- *Non-zero probability of coincident stress events* – in reality, a scenario in between the extremes where stress events coincide some of the time is most likely. The approach to de-rating should lie between that adopted in the hypothetical scenarios described above.

There are two possible approaches to de-rating interconnected capacity:

- **A probabilistic approach** to assess the likelihood of coincident stress occurring in future could be taken, based on historic data or simulations of the risk of loss of load (such as that used to estimate the capacity to purchase in the CM). If, for example, an interconnector was not expected to flow at full capacity into GB during 1 in 5 stress events, it could be de-rated to 80%. This would be in addition to any de-rating due to physical reliability. This approach is consistent with the treatment of domestic generation in the GB market.
- **An alternative approach** would be to allow interconnected capacity to decide on the de-rating, because they bear the risk of non-delivery and are best placed to understand their own reliability. This approach is not consistent with the proposed GB treatment of domestic generators. If applied, it could lead to excessive risk taking, or gaming opportunities.

Based on the analysis above, we suggest that irrespective of the approach taken to include interconnected capacity in the CM, de-rating of interconnector capacity should be undertaken on the basis of a probabilistic view of the likelihood of coincident stress events, in combination with de-rating related to physical reliability. This calculation could be conducted in consultation with neighbouring TSOs.

3.1.2 Imperfect markets

Power does not always flow over interconnectors towards the country with the highest price, suggesting that there are inefficiencies in the despatch of power. Therefore, the interconnector may not be able to deliver power at times of stress in GB, even when the market at the other end of the interconnector is not at stress.

The existence or severity of a stress event may not always be known a day ahead of delivery, so the outcome of day-ahead market coupling⁵ will not be able to take it into account. In which case, the ability of an interconnector to fulfil its

⁵ Day-ahead market coupling is a procedure whereby markets to determine flows across interconnectors and for buying and selling energy in the adjacent balancing zones are cleared simultaneously for each hour of the following day. This procedure has been implemented throughout much of Western Europe.

obligation rests at least in part on the efficiency of the intra-day market and cross border balancing arrangements between TSOs.⁶

Coupled cross-border intraday markets are currently less well established than coupled day-ahead markets on some GB interconnectors. Market participants currently compete for available interconnector capacity in intra-day auctions before making transactions in the two adjacent energy markets and nominating a flow over the line. Further, balancing markets operate generally within balancing zones with limited sharing of flexibility resources over the interconnectors. In GB, there are currently cross-border TSO-TSO balancing arrangements in place on IFA (the interconnector between GB and France) and reserve sharing with Ireland.

The key question for policy makers is whether these imperfections are likely to persist in future. The EU's Third Energy Package has triggered significant reforms with the aim of creating a single European energy market. A series of network codes are in development setting out how this single market should operate. These codes are the building blocks for the European Target Model (ETM).

There are three market codes, Forward Capacity Allocation (FCA), Electricity Balancing (EB), and the most relevant code to this discussion, Capacity Allocation and Congestion Management (CACM). CACM sets out the methodology for allocating capacity between different market zones in all timeframes i.e. it aims to create a single approach to cross-border electricity trading. A key part of the code concerns harmonised cross-border intra-day markets, leading to a more efficient allocation of interconnector capacity much closer to real-time. Implementing the ETM will therefore be important for reducing market imperfections in interconnector flows. As already noted day-ahead market coupling has progressed on a voluntary basis, and a similar project is planned for intra-day market coupling. Full implementation of the ETM is however not scheduled for completion until 2019-20.

The ETM for intra-day markets is based on continuous implicit trading⁷. Following implementation, there should be a market place for traders (both domestic and abroad) to see bids and offers after a market stress event has been called in GB. And, as long as there is a platform available, then generators will be able to respond to bids from the GB retailers looking to supply their customers during the period of scarcity and from the GB generators and traders looking to

⁶ This assumes that interconnector flows induced by balancing actions are allowed to count towards an interconnector's obligation.

⁷ Implicit trading is like market coupling in that interconnector capacity is implicitly traded as a bundled product with energy market trades.

cover their contractual obligations for the sale of power. This should create greater confidence in the ability of interconnectors to respond to prices intra-day.

It is important to note that, at least in this context, there is not a need for a particularly deep and liquid intra-day market. Rather, there simply needs to be a platform which will provide enough of a signal to generators in interconnected markets of GB generators', retailers' and traders' high demand for (and high valuation of) additional volumes. This signal can simply be made through the placing of very high priced bids for volume which can be seen by interconnected generators⁸ and does not itself require particular depth.

Under the ETM, intraday markets are not, however, the last opportunity to ensure that power flows to the most stressed market. Cross-border balancing offers a further opportunity for interconnector flows to respond to the stress event.

The European Network Codes require that TSOs have the scope to trade bilaterally with neighbouring markets to utilise reserved or spare interconnector capacity to assist with system balancing. During a stress event, TSOs could therefore seek to source balancing actions from interconnected capacity and so help to ensure the interconnector flowed in the direction of the country with the stress event. There may be scope to improve coordination further, for example, through TSOs scheduling of slow response generation in advance of gate closure. This would require the development of commercial terms between TSOs and regulatory approval.

Arguably, exchange of TSO balancing energy is even more secure than intraday cross-border trading. It relies on bilateral organisation by two TSOs, one at either end of the interconnector, rather than by a potentially large number of market participants.

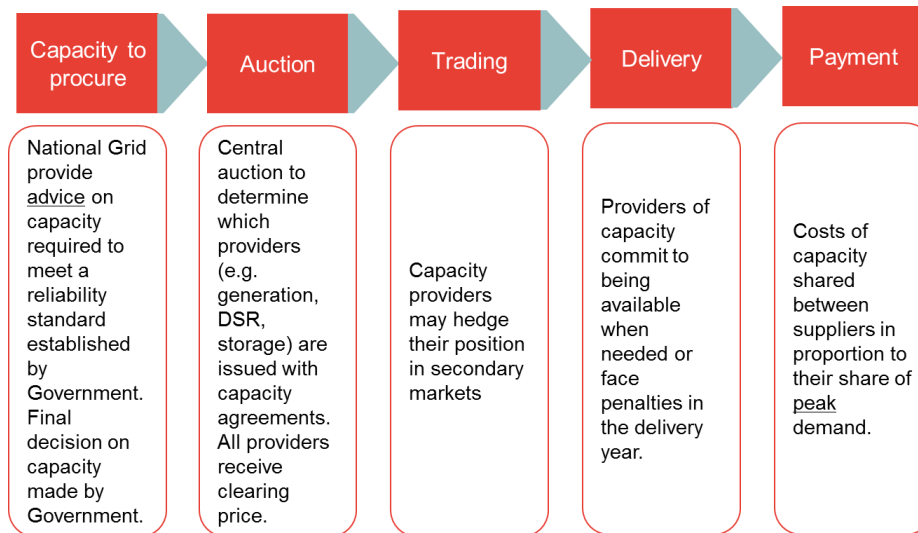
Through the implementation of the ETM, there is significant scope for policy makers and regulators in Member States to ensure the flows from interconnectors are more secure. Failure of the interconnector to flow towards a market in stress with higher prices would, under the ETM model, represent a significant market and institutional failure. The degree to which policy makers are successful in this does have potential implications for the most appropriate option to recommend. It is for this reason that there is a key interdependency between our final recommendation and the development of the ETM.

⁸ We refer to interconnected generators since these are the parties that may be able to adjust their physical production plans to make power available to flow to GB. However, a trader or retailer operating in the adjacent market could also be the party to trade across the interconnector.

3.2 Enabling participation

We now develop in more detail practical options for the integration of interconnected capacity in the GB CM. In doing so, we begin by considering the five stages of the proposed CM design in GB, and consider how each of these may need to be adapted to allow for the inclusion of interconnected capacity.

Figure 1. Stages of proposed CM in the GB market



Source: Based on 'DECC Electricity Market Reform: Capacity Market – Detailed Design Proposals' (June 2013)

The following stages may require change, but it is less likely to be significant in nature:

- **Capacity to procure** – there is no reason why the total capacity that the GB market would want to procure, or the approach to calculating it, would change whether interconnected capacity is allowed to bid into the CM or not. A key input into the capacity calculation is the flow expected from an interconnector in peak periods and this is unlikely to change significantly whether they can participate or not. There may be a small impact, depending on the option chosen, on the assumed flow from interconnectors in the capacity calculation. For example, an option which is better at 'securing the flow' could increase the expected flow during a stress event.
- **Trading** – non-GB capacity should be able to make financial or physical trades to manage risk in a similar way to GB capacity. For example, an interconnected generator, or interconnector (depending on the option chosen) could trade out of their physical obligation with another unencumbered pre-qualified generator in GB. Equally, a domestic generator

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should be able to trade with unencumbered pre-qualified interconnected generators or interconnectors should they exist. There may be particular issues in the details of transferring obligations cross-border, but the overall principles should remain the same.

- **Payments** – the cost of the capacity market should be shared across GB suppliers whether non-GB capacity is included or not.

However, there are clear implications for the auction and delivery stages of the process:

- **Auction** – a model for interconnected capacity needs to be clear as to who can bid into the auction and at what capacity they can bid. There is a set of important questions that we look to answer through our discussion of the different strawmen:
 - What are the benefits of different potential bidders into the auction? For example should the IC owner bid directly, should non-GB generators⁹ using the IC be able to bid, or should no party bid at all but simply receive payments?
 - Should the same rules apply to interconnected capacity in the CM auctions as apply to domestic generation capacity?
 - Who receives the capacity payments and who ultimately benefits?
 - How can the amount of capacity able to bid into the CM be rationed in line with the de-rated capacity of the IC?
- **Delivery** – the model needs to set how to verify that interconnected capacity has met its obligation and who faces the penalties for failure to fulfil the obligation during a stress event:
 - Is the basis of the capacity obligation ‘availability’ or ‘delivery’ i.e. does non-GB capacity simply need to be physically available or is verification of power flow over the IC required?
 - Should interconnected capacity face penalties in the same way as GB generation capacity?
 - How can interconnected capacity manage the risk of penalty payments? Which party is best able to manage this kind of risk?

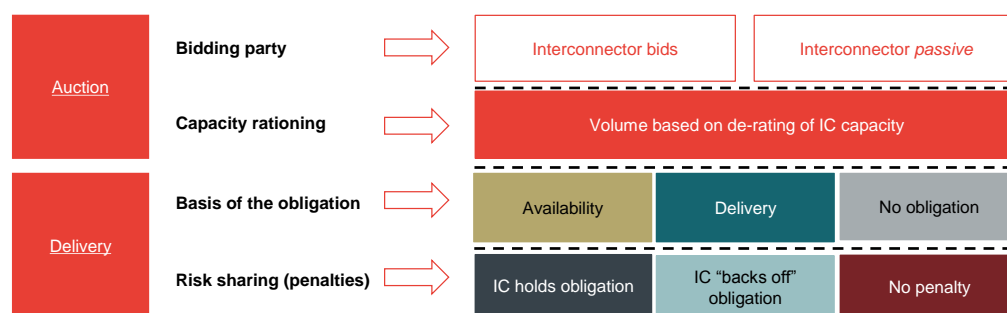
⁹ In theory DSR could bid as well in a model where generators are the bidding party instead of the IC. However, there may be additional practical issues in working directly with foreign industries as opposed to generators.

These questions can be used to construct a set of potential options for assessment, as shown in **Figure 2** and **Figure 3**. They identify the potential options for the key auction and delivery design questions we have set out, grouped by the party able to participate in the CM auction. The options related to the participation of interconnector owners are considered first, followed by those for external generators.

3.3 Interconnector options

With interconnector options, the interconnector owner may participate in the CM, while external generators would not have a direct relationship with the CM. **Figure 2** sets out potential interconnector options for assessment.

Figure 2. Building blocks for interconnector options



Source: Frontier Economics

3.3.1 Bidding party

For the interconnector options the main auction design question relates to whether the interconnector owner actively participates by bidding in the CM auction, or simply receives a capacity payment i.e. is passive.

- In the first option the interconnector owner itself, whether a merchant or regulated operator, is the designated party able to bid into the CM. If its bid is successful, it is the recipient of the capacity payments and will be liable to pay the penalties if it does not fulfil its obligation. The interconnector owner receives the capacity payments, but the ultimate recipient of the payments depends on the regulation of the interconnector. They are treated as incremental revenues for a purely merchant interconnector, directly supporting the case for investment in new interconnector capacity. If the capacity payments are included as revenues under the cap and floor regime, they may ultimately flow back through to consumers, e.g. in cases where capacity market revenues would contribute to the interconnector revenues exceeding the cap.

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- In the alternative interconnector option which leaves the owner passive, the interconnector owner is paid the CM clearing price for its de-rated capacity. Similarly, capacity payments may flow back to consumers if the payments are included under the cap and floor regime. This option is described by the EC as a potential interim step to ensure that investment in interconnectors is not undermined¹⁰.

3.3.2 Capacity rationing

We have already set out how the capacity of the interconnector could be de-rated to reflect the additional risk that the interconnector may not flow into the GB market at times of stress. This is an additional de-rating factor to that based on the physical reliability of interconnectors, and therefore reflects a different methodology for de-rating compared to domestic generators. The rationale being that, if a domestic generator is physically available, power will flow onto the GB network when despatched. The same is not true for an interconnector, where the flow onto the GB network is driven by other market factors in addition to its physical availability.

3.3.3 Basis of the obligation

There are more potential options when considering the delivery phase of the CM design. A central question in defining our options is whether the obligation is on ‘availability’ or ‘delivery’. For an interconnector owner this is the difference between a requirement to be physically available and a requirement for the power to flow over the interconnector into GB during a stress event at or above its de-rated capacity. There is a further option of not placing an obligation at all on the interconnector. The three options are:

- The interconnector only has to be *available* to supply power in order to avoid the penalty. Therefore, it only needs to be able to manage its own physical reliability, enabling flows scheduled by the market, but not the power flow over the interconnector. This will insulate the interconnector from a risk which may be largely out of its control.
- The interconnector fulfils its obligation if the market *delivers* the correct amount of energy through the interconnector at times of stress. This highlights a key feature of this model, which is the exposure of the interconnector owner to a risk which may be out of its control i.e. the interconnector may be physically available to flow. However, due to a

¹⁰ EC, Generation Adequacy in the internal electricity market – guidance on public interventions, November 2013

coincident stress event or market imperfection, it may not flow into GB at a time of stress at its de-rated capacity. For merchant investors, this affects directly their investment case (or appetite to participate in the CM in the first place). For regulated links, whether it affects the investment case will depend on the regulatory treatment of the penalties i.e. whether the interconnector owner is fully exposed to the penalty, or whether the risk is shared. This is still to be determined by Ofgem.

- The interconnector owner does not assume any penalty payments for non-delivery despite being paid the capacity market clearing price. This most likely relates to a situation where the interconnector is a passive participant in the CM.

Risk sharing (penalties)

Depending on the type of obligation placed on the interconnector there are different options for how penalties are levied and the way risk is managed. The interconnector could hold the obligation and bear the full risk of not fulfilling that obligation. Alternatively, the interconnector owner could choose to pass on the market risk (i.e. the exposure to penalties in the absence of flow over the interconnector) to another party. In other words, they could share the capacity payments and the risk of penalty payments with another party e.g. the TSOs or external generators.

From DECC's point of view these contractual arrangements do not need to be tightly defined by policy. The concept of the interconnectors laying off commercial risks is well accepted in other areas of their business (e.g. a maintenance contract)¹¹.

Two potential options for passing on the risk are:

- Pass the risk to the TSOs of the markets on either side of the interconnector. The failure of the line to flow to GB could be seen as a collective failure of prices to rise in GB and all generators outside GB to react to a market stress situation in GB. The TSOs can manage this risk to some extent through cross border balancing market arrangements, and therefore may be willing to take some of the risk if permitted to do so (in exchange for some of the capacity payments, which may or may not be passed back to customers through regulation). If the interconnector is jointly owned by the TSOs (with ownership and SO responsibility) on either end of the line, then this may occur by default, subject to business separation

¹¹ For example, an interconnector may choose to sign a maintenance contract with penalties on the contractor should the availability of the line drop below a certain level.

requirements. However, this is unlikely to be the case in GB where these roles are typically separated in the case of interconnectors.

- Similarly the interconnector owner could choose to contract with a group of external generators – acting in effect as an agent for external generation in the CM. Under this model, the interconnector might first hold an auction for the use of its de-rated capacity to bid into the CM (as set by the GB CM). The clearing price in this auction is the basis for the marginal price which the interconnector submits in the GB CM, and the capacity payment to external generators. The interconnector owner still holds the obligation, but the payments and penalties are passed back through to generators based on the contractual terms of the auction run by the interconnector. At a high level the money flows can be summarised as follows:
 - generators receive the clearing price in the auction with the interconnector;
 - the interconnector receives the GB capacity payment less payments to generators; and;
 - the allocation of risk is subject to the terms of the contract. One possible allocation is where the penalty would fall on the interconnector when the line is physically unavailable, and on generators which had bought a ticket in the auction when the flow is not delivered. This could make sense because, although generators individually may not affect the flow, they can have a marginal impact (which is greater than that of the interconnector and greater if they are large relative to the overall market). Consequently, they may be happier to bear the risk than the interconnector.

3.3.4 Summary of interconnector options

These building blocks lead to five different interconnector options for assessment, which are summarised below in **Table 2**.

Table 2. Summary of interconnector options

Option	Bidding party	Obligation type	Party ultimately holding the penalty risk
1	Interconnector	Availability	Interconnector
1a	Interconnector passive	n/a	n/a
2	Interconnector	Delivery	Interconnector
2a	Interconnector	Delivery	TSOs
2b	Interconnector	Delivery	External generators

Source: Frontier Economics

Although there are more than five potential combinations of the ‘building blocks’ set out previously, it does not make sense to cover them all. For example, there are not three options for risk sharing for each type of obligation. In an availability model, the interconnector owner is best placed to manage the risk of physical availability of the line and hence does not need to back off the obligation onto another party.

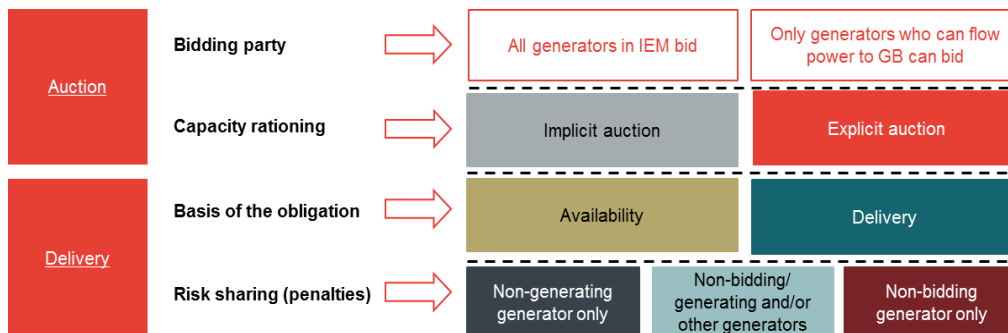
Similarly, option 1a does not assume any penalty payments for non-delivery. If it did, the interconnector owner would face a penalty if the line were physically unavailable and, as a result, the option would become an availability based model where the IC owner holds the obligation. Assuming the CM clearing price is unaffected by the presence or not of the IC in the auction, then the addition of penalties makes this option identical to option 1.

3.4 External generator options

In these options, generators outside GB bid directly into the GB CM (instead of the interconnector owner). The total bids from these generators should not exceed the de-rated capacity allowed for each interconnector (de-rated using the same methodology set out in our discussion on ‘securing the flow’). The generators themselves receive the capacity payments directly and pay the penalties for not meeting their obligation.

Figure 3 sets out potential generation options for assessment.

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Figure 3. Building blocks for interconnected generator options

Source: Frontier Economics

3.4.1 Bidding party

In considering the participation of generators, an important question concerns whether there should be limits placed on the location of generators eligible to bid and, if there are to be limits, what is the process that sets those limits. It is clear any generators that have unconstrained access to the interconnector can contribute to GB system adequacy. However, it is possible that generators in other countries further away in the IEM could also provide a contribution. We assess two potential approaches to assessing the eligibility of generators based on their location.

- *Unrestricted option* – in this option participation in the GB CM is allowed from any generator within the IEM. This essentially makes an assumption of a ‘copper plate’ network across Europe i.e. a generator in a country not directly connected to GB, e.g. Austria, is assumed to be able to provide the same contribution to GB system adequacy as a generator in France. The generator, wherever it is located, is able to bid for a share of the de-rated interconnector capacity to gain a right to participate in the GB CM. The obligation and penalty regime would not vary by location.
- *Restrict eligibility on the basis of contribution to GB system adequacy* – in this option capacity that bids into the CM is de-rated according to the likelihood that power will flow and make a positive and material contribution to GB during a system stress event. In effect this would imply that remote capacity, which is separated from GB by numerous congested interconnectors and is unlikely to provide any contribution to GB system adequacy will be de-rated to zero. This de-rating could take place during prequalification on the basis of its specific location, requiring a complex calculation to be applied to bids. Inevitably, it will not be possible to de-rate each bid perfectly, although this

approach should restrict bids to those plants with a reasonably high probability of delivering power in a stress event.

3.4.2 Capacity rationing

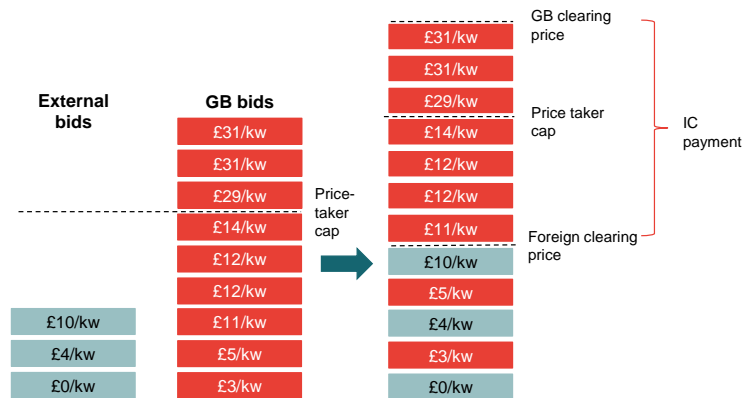
Capacity contracts sold to generators need to be rationed to the de-rated capacity of the interconnector¹². This could be achieved either through an explicit or implicit auction mechanism, and this mechanism will be the means by which value flows to interconnector owners to support investment in interconnection.

- **Explicit auction** – in this model the total de-rated capacity of the interconnector could be sold to external generators before CM participation in the form of ‘tickets’, which qualify them to bid into the GB CM. Since this is the route through which the interconnectors can earn value, they will be incentivised to organise the ticket sale themselves, removing the need for DECC to directly design the auction. The price which generators are willing to pay for the tickets will reflect the expected capacity revenue, as the tickets are the ‘gateway’ to the capacity market. A reserve price could be used to mitigate concerns about market power.
- **Implicit auction** – in this model revenue is allocated between the external generators and the interconnector as part of the main GB capacity auction. External generators receive a lower clearing price based on the most expensive foreign bid in the CM auction, with the interconnector receiving the difference between the GB and foreign clearing prices. An illustrative example is set out in **Figure 4**. This type of auction was part of an option set out by Eurelectric¹³.

¹² Individual bids from external generators may also need to be de-rated according to their physical risk of outages in the same way as domestic generators.

¹³ Eurelectric, ‘Options for coordinating different capacity mechanisms’, December 2013.

Figure 4. Illustrative example of an implicit auction structure

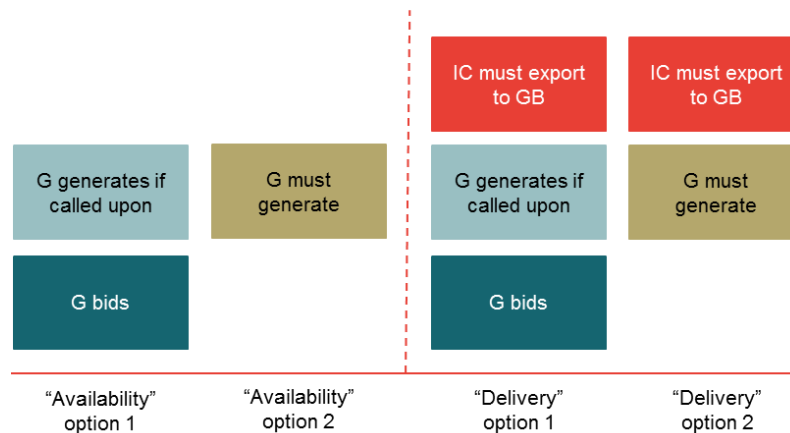


Source: Frontier Economics

3.4.3 Basis of the obligation

Measuring ‘delivered energy’ in generator options is more complex as it depends on not only the generator, but also the flow over the interconnector. In the same way as the interconnector options, an option is defined as an ‘availability’ or ‘delivery’ model depending on whether power must be delivered into the GB market or not. In the generator options, there is a further question about what the obligation means for a generator’s own behaviour.

Figure 5 sets out the potential range of options for defining availability and delivery. Availability options could require generators to demonstrate their availability by bidding into the relevant market, but generating only if called upon. Alternatively, the obligation could simply require plant to generate. Delivery options could be defined in the same way, with the additional requirement of the IC flowing into GB.

Figure 5. Defining availability and delivery in generator options

Source: Frontier Economics

Whether a plant is generating can be assessed using metering data. 'Bidding' however needs to be defined, as it will vary depending on the timescale (e.g. day-ahead or intra-day), and the progress in developing the ETM¹⁴. For stress events known about:

- *At the day-ahead stage* – 'bidding' could represent offering power on the relevant market coupled exchange for the interconnector, if they haven't already nominated a flow using a long-term physical transmission right.
- *At the intra-day stage* – if they haven't already nominated a flow or were not successful in the day ahead auction then they would be required to bid into the intra-day market. The definition of 'bidding' could vary depending on whether intra-day market coupling is in place or not.
 - *With full ETM implementation* there will be a continuously traded cross-border intra-day market which combines energy and interconnector capacity into a single product. In this case, generators will be able to place offers on this platform at a reasonable price to be taken up by suppliers in GB (or elsewhere in the market coupled region) if required.
 - *With the current intra-day market arrangements* to export power to GB in the intra-day market a generator may need to participate in the intra-day auction for capacity (should spare capacity still be available), and if

¹⁴ 'Bidding' raises the question of identifying additionality when the obligation is held by a large portfolio player. Therefore it may be important to be prescriptive about exactly what bidding means, defining clearly both the market(s) and timescales involved.

successful nominate a flow that corresponds to a separate bilateral trade made with a GB supplier. ‘Bidding’ therefore, until full ETM implementation is complete, could refer to the participation in the intra-day auction for capacity and its subsequent nomination.

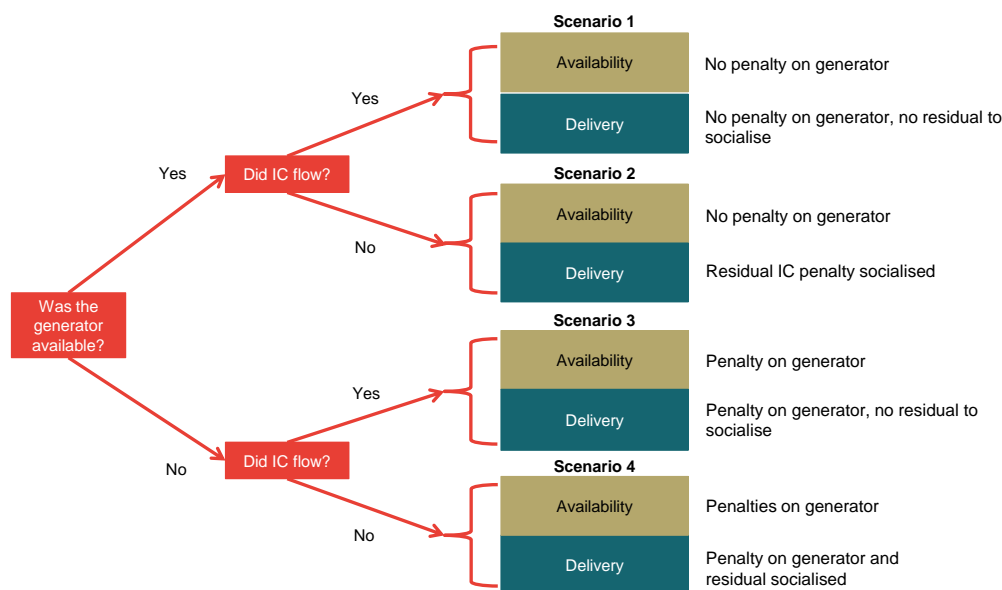
3.4.4 Risk sharing (penalties)

Penalties are charged in each of the models, but their design is dependent on the availability or delivery option.

- In an *availability model* the generator pays directly any penalties that accrue for failing to fulfil its obligation. This is based only on its actions as a generator, whether it is a requirement to generate or at the minimum bid into the relevant market. It is not related to the flow of the IC.
- In a *delivery model* failing to deliver on its obligation is not only based on its availability, but also on whether the interconnector flows in the correct direction and at the correct volume during the stress event.

There are therefore a range of scenarios for how individual generators could be charged during a stress event, set out in **Figure 6**.¹⁵ This diagram illustrates how the different combinations of generator actions and interconnector flows can lead to different penalty outcomes. For simplicity, we have not distinguished in the diagram between the two ‘availability’ or two ‘delivery’ models set out in **Figure 5**. By that we mean, whether the generator is ‘available’ could refer to either a requirement to generate, or at a minimum ‘bidding’ in the relevant market. The first question in the **Figure 6** simply refers to whether the generator meets its part of the obligation.

¹⁵ In these examples, for simplicity, we assume that the interconnector is physically available to flow.

Figure 6. Penalty charging scenarios in generator options

Source: Frontier Economics

In the case of an availability model, the penalties in scenarios 2 and 4 are the same, despite differences in flow on the interconnector. There are no penalties in both scenarios 1 and 3.

In the case of a delivery model, where for example, there is an obligation on generators to be generating (delivery model 2), the penalty scenarios could be as follows:

- **Scenario 1** – The individual generator is generating to its full obligation, and the interconnector fulfils its obligation. In this situation, there is no penalty.
- **Scenario 2** – The individual generator is generating to its obligated level, but the interconnector does not flow at its full obligated level. The penalty for the shortfall in flow from the interconnector is socialised across all generators with a CM contract. This penalty represents residual risk on a generator that they are arguably not well placed to manage e.g. the risk of coincident stress events or market imperfections.
- **Scenario 3** – An individual generator fails to generate (or bid) due to a physical fault but the interconnector still fulfils its obligation. In this scenario the generator faces a penalty, even though its shortfall in generation did not worsen security of supply in GB. The shortfall was covered by the actions of other generators (outside of the CM) taking advantage of high prices over the interconnector.

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- **Scenario 4** – The generator fails to generate (or bid) due to a physical fault and the interconnector fails to fulfil its obligation. The individual generator receives a full penalty based on the shortfall on its contract. This penalty is netted off the penalty for the overall shortfall in flow over the interconnector, with the remainder socialised across all CM generators (including the generator that failed to generate).

There may also be risk sharing between generators and the interconnector owner. For example, if the interconnector does not flow due to an outage, the interconnector owner could pay the penalty. The risk could be transferred between the parties through the contractual terms of the explicit or implicit auction.

3.4.5 Summary of generator options

The building blocks set out in **Figure 3** can be organised to create 16 generator options.

Table 3. Summary of generator options

	Obligation type	Obligation on generator		Rationing interconnect- or capacity	Restrictions on generator participation
		<i>Interconnector flow</i>	<i>Generation</i>		
1	Availability	No obligation on flow	Generate	Explicit	None – all IEM generators can participate
2	Availability	No obligation on flow	Generate or bid	Explicit	None – all IEM generators can participate
3	Delivery	Must flow into GB at least at de-rated capacity	Generate	Explicit	None – all IEM generators can participate
4	Delivery	Must flow into GB at least at de-rated capacity	Generate or bid	Explicit	None – all IEM generators can participate
5	Availability	No obligation on flow	Generate	Implicit	None – all IEM generators can participate
6	Availability	No obligation on flow	Generate or bid	Implicit	None – all IEM generators can participate
7	Delivery	Must flow into GB at least at de-rated capacity	Generate	Implicit	None – all IEM generators can participate
8	Delivery	Must flow into GB at least at de-rated capacity	Generate or bid	Implicit	None – all IEM generators can participate
9-16		<i>As per the options above</i>			Generator participation based on their realistic contribution to GB system adequacy

Source: Frontier Economics

3.5 Contract length

A further design consideration relates to the contract length that interconnected capacity should receive. This raises issues that cut across both interconnector and generator led options and so are discussed here in one place. One option could be to treat interconnected capacity the same as domestic capacity i.e. all receiving a one year contract, unless they meet certain criteria to qualify for a 3 year refurbishment or 15 year new capacity contract. However, there are other potential options which are worth considering given differences between interconnected capacity and domestic generators. Three options are set out in **Table 5**.

Table 4. Options for contract length in both interconnector and generator options

Option	Description
1 Same as domestic capacity	Existing and new capacity receive one and 15 year contracts, respectively. Price and volume are fixed for duration of the contract.
2 One year contracts only	Existing and new capacity receive one year contracts only. Price and volume fixed for the duration of the contract.
3 Variable volume contracts	Existing and new capacity receive one and 15 year contracts, respectively. Price fixed for duration of the contract but volume can vary.

Source: Frontier Economics

The options vary according to the contract for new capacity. Option 1 is an equivalent approach to GB capacity, which could be a sensible approach if an objective is to support investment in interconnection on a comparable basis to domestic generation. However, there are a number of potential concerns with this approach:

- First, a 15 year contract does not allow the de-rating of the line to be adjusted based on the performance of the interconnector over time e.g. the market risk associated with the interconnector not flowing perfectly may improve over time, or equally the risk of coincident stress events may grow with increased renewable generation across Europe. If the level of secure capacity for interconnectors was thought to be more variable than that for domestic generators, it may be desirable to adjust the de-rating factor for the capacity of the line to allow a greater or smaller volume of interconnected capacity to bid in the next auction. A one year contract could therefore be better in this regard.

- Second, future work to harmonise the approach across Europe may require a transition towards a new option for the treatment of interconnected capacity. Long-term contracts may create barriers and increase the cost of any transition. For example, switching to a generator-led option will prove more complex should there exist a number of interconnectors with long-term capacity agreements.

One year contracts (option 2) may be viewed as less likely to be sufficient to support new investment in interconnection. There may be potential to mitigate this through a 15 year contract for new capacity at a fixed price from the initial auction. But the volume could vary based on the flow performance of the line (option 3). This however, may offer little additional comfort for the investor making it hard to secure project finance. These risks associated with options 2 and 3 may however be less critical than for domestic generation, depending on the incentives and insurance provided by the broader regulatory framework. There may be a rationale therefore for limiting the award of longer term contracts to interconnected capacity.

4 Developing a set of criteria for assessment

Each option presented above is assessed against a set of criteria. These capture the main categories of societal costs and benefits such as efficiency and security of supply. They also consider the practicality of the option for DECC and delivery institutions, and the consistency with EC policy now and in the future.

Our approach to choosing the criteria was based on the following steps:

- we considered the specific objectives for the GB capacity market, as well as wider Government objectives for energy policy;
- we identified the objectives whose attainment were most likely to be affected by the design choices we were considering;
- we identified the key constraints that European legislation and guidelines may create for our options; and
- we narrowed down the options to a focused list of criteria through discussions with DECC.

Our criteria are outlined in **Table 5**.

Table 5. Criteria for option assessment

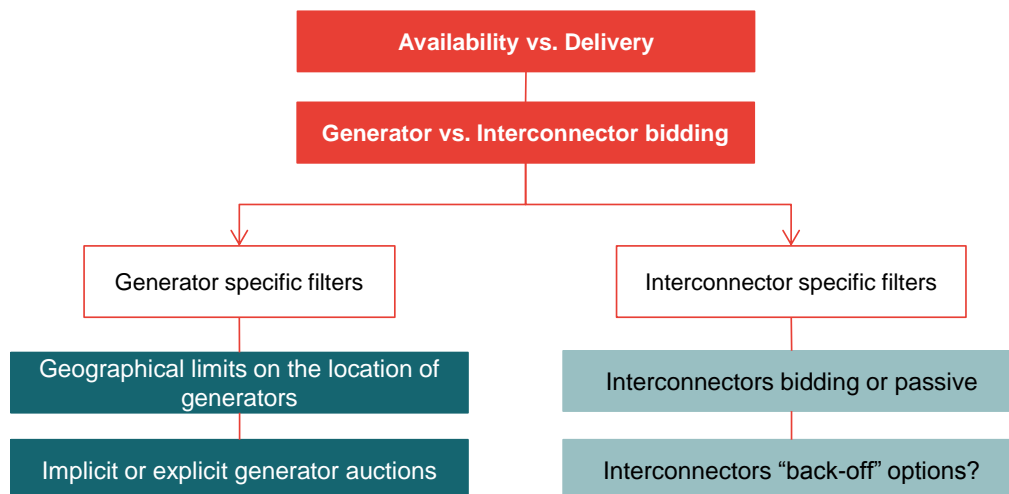
Criteria	Description
Efficiency	Does the option avoid reduced incentives for investment in interconnection relative to generation, and avoid distortions to short-run despatch? This includes, where relevant, an assessment of the allocation of risks between different parties i.e. are the risks allocated to the party most able to manage them? Further, does the option lead to unintended consequences and gaming risks? For example, are there opportunities for parties to exploit market power?
Security of supply	Does the option ensure sufficient capacity is available in a stress event? For example, are there differences in the probability of power flowing into GB during a stress event? The answers to these questions may be dependent on the state of implementation of the ETM.
Costs to GB consumers	Is the cost of ensuring security of supply increased or decreased for GB consumers? This is closely linked to the efficiency criteria above. For example, due to inefficient investment decisions in interconnection. Or, because a lower probability of flow over the interconnector increases the investment requirement from domestic capacity. Costs to GB consumers could also be affected by the cost and complexity of implementing and running the option.
Equity (GB vs. non-GB capacity)	Are non-GB and GB capacity treated fairly? This covers fairness in participation of the CM e.g. do foreign and domestic capacity face exactly the same rules, or do they face the same balance of risk and reward.
Deliverability	How complex is the option to implement? This covers whether the options entail new institutions or complex contracting arrangements?
Consistency with the EC	Would the option raise potential concerns with the EC regarding the implementation of the European Target Model and state aid guidelines? Is the option compatible with the ETM? Is the option consistent with the direction of EC CRM policy? For example, is a particular type of option favoured as an enduring European wide solution, and are there advantages of being consistent with that now to avoid future costs of change?

Source: Frontier Economics

5 Assessing the options

In this section we assess each of the options against the set of criteria set out above. Our approach to the assessment is to focus on each of the key building blocks. By assessing each against the criteria we can build up a set of the most highly ranked features contributing to a preferred option. In effect, by addressing each of the characteristics we are able to ‘filter’ the options. For example, by assessing the choice of ‘availability’ versus ‘delivery’, we are able to filter out from consideration all the options with a particular obligation type. The structure of our assessment is set out in **Figure 7**.

Figure 7. Assessment ‘filters’



Source: Frontier Economics

5.1 Availability versus delivery models

The basis of the obligation placed on the bidding party is of central importance to all of the options. This section discusses the relative merits of availability and delivery models in the context of the assessment criteria, taking each criteria in turn. However, the majority of the discussion is focussed on the potential trade-offs between efficiency and security of supply, and an assessment of any barriers created by the European regulatory context. It concludes with a recommended way forward.

5.1.1 Efficiency

In the assessment of availability and delivery models there is potentially a trade-off between investment efficiency and despatch efficiency.

- **Investment inefficiency** arises due to an ‘implicit subsidy’ in availability models, although there is the potential for its impact to be mitigated for projects under the cap and floor regulatory regime, but not for purely merchant projects.
- **Despatch inefficiency** could arise where there is a requirement or incentive for generators to generate power. This is more likely in delivery models but could also arise in availability models. These distortions are likely to be small and infrequent, and can potentially be mitigated through the design of the obligation.

Investment efficiency

Investment in interconnector capacity is supported by capacity revenues in both availability and delivery models. These flow directly to the interconnector when the interconnector owner is the bidding party, and indirectly through an explicit or implicit auction where the generators are the bidding party. The focus on investment efficiency in this section relates to the effect on efficiency of the options for CM participation. There are other potential reasons why efficient levels of investment in interconnection might not take place, which are being investigated through Ofgem’s Integrated Transmission Planning and Regulation (ITPR) programme. This section also only considers the efficiency of decisions to build domestic generation or interconnection.

In an availability model the interconnector (or generators) is not exposed to the risk that the interconnector does not flow into GB during the stress event i.e. it is insulated from the risk of coincident stress events on both ends of the cable, or the risk that markets do not result in power flowing to the market with the highest prices. Insulating the interconnector from this risk provides a stronger signal for investment.

Under this option the delivery risk is transferred to GB consumers for interconnection but not for domestic generation. If the interconnector is actually less reliable than domestic generators, which face a delivery obligation, exempting it from penalties may represent an implicit subsidy to interconnection. This could distort investment decisions and lead to over investment in interconnectors at the expense of potentially cheaper domestic capacity options. A delivery model may therefore be more likely to lead to an efficient level of interconnection investment since the interconnected capacity is remunerated for the actual security of supply benefit that the interconnector provides, in the same way as for domestic generation.

The implicit subsidy in an availability model will directly benefit purely merchant investors in interconnection (i.e. those that have chosen to opt out of the cap and floor regime) potentially supporting additional investment. To the extent possible it is important to set investment signals using markets. However, at the margin

Assessing the options

inefficiencies could be mitigated using regulation. For regulated interconnectors under the cap and floor regime, there is the potential for the regulator to account for the presence of any implicit subsidy in the cost-benefit analysis of whether the interconnector should be granted regulated cap and floor revenues, thereby limiting the distortion. It is likely that in the medium term the majority of new interconnector investment will be regulated. Therefore, as long as the marginal investment in interconnection is regulated in this way, regulators do have some control over the total amount of new investment and could choose to account for any distortions in the quantity of interconnection.

Despatch efficiency

There is potential to create despatch inefficiency during a stress event in some of the options. Given stress events are expected to be rare these are likely to be small and infrequent. The distortion could arise if incentives on interconnected generators from the CM result in a desire to generate out of least cost order during a stress event. Generators in the foreign market could achieve this by selling power in the day-ahead, intra-day or balancing markets, at a discounted cost reflecting the avoided penalty payment from generating. It could occur directly where the generators are the bidding party, or indirectly if the interconnector ‘backs-off’ their delivery obligation to generators.

This distortion is most likely to occur when the CM obligation requires the generators to generate. It should be noted that if markets are operating efficiently, and the interconnector is already flowing at full capacity into GB then requiring generators to generate provides no additional security of supply benefit (this is discussed further below). If the generator only has to bid in the relevant market then the risk of despatch inefficiency is lower but may still be present. For example, in a model where a generator is faced with a delivery incentive, but is only required to bid in the relevant market there could be a number of possible outcomes. If the generator believes that the interconnector will not correctly respond to the stress event it may either:

- seek to incentivise other cheaper generators to generate, resulting in no distortion; or
- run out of time to coordinate with other generators¹⁶, or see too much risk in doing so, and decide to generate itself leading to a distortion.

The risk of a distortion during a stress event is lowest in an availability model where generators don’t have to generate themselves (i.e. when the requirement is that the interconnector is available and generators are just required to bid),

¹⁶ This is especially the case pre-ETM, where there are a number of transactions in capacity and energy required to ensure the interconnector flows.

although there may still be small distortions related to testing. The expected despatch distortions associated with the different availability and delivery options are summarised in **Table 6**. It highlights that there are potential distortions in both of the generator delivery options¹⁷, and an interconnector delivery option where the obligation is backed off onto generators. The availability options will not lead to a distortion except where a generator is required to demonstrate its availability by generating.

¹⁷ It is possible that in a generator delivery model where the requirement is to generate, some of the distortion could be mitigated by allowing generators to physically trade the obligation to another generator. However, this would add significantly to the complexity of the arrangements.

Table 6. Summary of effect of availability and delivery models on despatch efficiency

Bidding party	Obligation	Despatch distortion
Availability models		
Interconnector	Availability	No distortion
Generator	Availability – generator must generate	Potential distortion as generators must generate to demonstrate availability
Generator	Availability – generator must bid or generate if called upon	No distortion and generators only despatched if ‘in merit’
Delivery Models		
Interconnector	Delivery but interconnector holds obligation	No distortion
Interconnector	Delivery but backed off obligation to TSO	No distortion. TSO incentivised to operate cross-border balancing market efficiently
Interconnector	Delivery but backed off obligation to generators	Potential distortion because generators incentivised to generate in order to influence flow over interconnector
Generator	Delivery – generator must generate	Potential distortion as generators obligated to generate
Generator	Delivery with generation or bidding – generator must bid or generate if called upon	Potential distortion although it could be minimised if generators able to sub-contract with alternative ‘in merit’ generation

Source: Frontier Economics

Testing regime

The discussion so far has focussed on the distortions that arise from generating during a stress event. But, the testing regime can also create incentives for generators to run out of merit. This occurs in the GB CM where there is a requirement to generate outside of the peak winter period because a generator has not sufficiently demonstrated reliability over the winter period. The magnitude of the distortion could potentially be viewed as minimal in the GB context. However incentives from testing will vary by country and whilst remaining small, may be larger for overseas generators where there are larger

plant margins i.e. there is an increased probability that plant will not run sufficiently during winter.

Irrespective of the option chosen, a testing regime is needed for foreign capacity to mitigate against the risk of poorly maintained generators. However, there could be good reason for mitigating these potential distortions further and not testing foreign capacity, at least as a transitional measure. In particular, if a domestic generator fails to meet its obligation then the capacity shortfall needs to be managed by the TSO. In the case of interconnected capacity, it is more likely that the capacity of the interconnector can be filled by alternative (unobligated) generators in the foreign market. The impact of a foreign plant failure increases as the size of the market decreases relative to the size of the interconnector i.e. plant failure in Ireland is of greater significance than plant failure in France.

In the longer-term it will likely be preferable for foreign plant to be tested¹⁸ by their 'home TSO' through reciprocal arrangements than by the GB TSO. This is more likely when neighbouring markets both have a CM and can offer testing services to the other.

5.1.2 Security of supply

The security of supply assessment is linked closely to the conclusion regarding efficiency. Security of supply is not likely to be made worse by any of the models. However, there could be a genuine security of supply benefit if additional flows into GB can be triggered during a stress event.

- *A delivery based model* by incentivising generators (directly in a generator model or indirectly in an interconnector option) to help the interconnector flow into GB, has the potential to provide additional power flows, improving security of supply. This result holds where interconnector flows do not already reliably respond in the intra-day market to a stress event. There is no security of supply benefit if the market responds efficiently and the interconnector flows into GB at full capacity irrespective of the CM.
- *An availability model* does not have the same ability to provide an additional power flow. In a scenario where there is spare capacity on the interconnector during a stress event, an availability model does not improve the probability that the interconnector will be flowing into GB during the stress event. This lower probability could be accounted for by increasing the de-rating factor on the interconnector to reflect its lower security value, potentially

¹⁸ In this case testing by 'home TSO' could imply the monitoring of self-despatch, as opposed to directing plants to generate out of merit.

weakening the economics of the interconnector investment and increasing expenditure on domestic capacity instead.

5.1.3 Conclusions from efficiency and security of supply analysis

Combining the discussion of efficiency and security of supply impacts provides a clear recommendation as to the most appropriate way for measuring ‘delivered energy’. We have set out that the potential differences in terms of investment efficiency between the models could potentially be mitigated by accounting for the ‘implicit subsidy’ inherent in an availability model, through the regulation of the interconnectors. Therefore in choosing the regime more focus should be placed on the trade-off between differences in despatch efficiency and security of supply.

Figure 8 illustrates that where there are potential inefficiencies in flows over the interconnector (‘less efficient markets’), a delivery based model can deliver real security of supply benefits, albeit at the cost of some despatch distortions. These distortions are likely to be small, given the infrequency of stress events, and only occur in the foreign market. However, they can be mitigated further through the design of the delivery incentive and the testing regime, whilst maintaining the security of supply benefits. In particular, the distortion from a delivery incentive could potentially be minimised by only requiring the generator to bid into the relevant market.

As market efficiency improves (‘efficient markets’), the ability to affect security of supply diminishes, however the potential for despatch inefficiencies remain. At which point an availability based model could be more sensible.

Figure 8. Interdependency between the choice of availability and delivery models and the efficiency of the market.

	Less efficient markets	Efficient markets
Availability model	No additional despatch inefficiency but missed opportunity to improve security of supply	No additional despatch inefficiency and no missed opportunity for security of supply benefit
Delivery model	Potential for despatch distortions but improved security of supply.	Potential for despatch distortions and no improvement in security of supply.

Source: Frontier Economics

We have already set out the importance of the ETM for determining interconnector flows. The pace at which it is delivered could also be important in determining the choice of a delivery or availability model. We therefore discuss it further here.

Intra-day market coupling will be delivered as a result of the implementation of the CACM network code. There is still significant work to do before it is fully implemented, and there are likely to be changes to its exact form as it passes through comitology. Although, the code is expected to be adopted by the end of 2014, the exact pace of implementation beyond that will be uncertain, and may not be complete until 2019-20.

Without the full development of the CACM code in particular, there may still be reasonable potential for interconnector flows to be inefficient and leave spare capacity on the interconnector during a stress event. Particularly if responding to a stress event is reliant on intra-day markets. Without certainty over the timing and success of the ETM development, a delivery based model could therefore be viewed as a sensible transitional option, with a longer-term ambition to move towards an availability based model as the ETM is fully implemented.

5.1.4 Cost to GB consumers

The assessment of cost for GB consumers is closely linked to the efficiency and security of supply discussion. A delivery model has the potential to reduce costs for GB consumers if it can provide an improvement in security of supply. The probability of flow into the GB market during a stress event is improved slightly

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allowing a small reduction in the domestic capacity requirement in the auction, lowering the clearing price and potentially reducing costs to GB consumers.

This benefit of the delivery model comes at a cost of potential, albeit small and infrequent, despatch inefficiencies and there is a small chance of a higher clearing price in the auction if interconnected capacity is eligible to be a price maker:

- The cost of despatch inefficiencies is unlikely to be borne directly by GB consumers since the inefficiencies represent an inefficient use of resources in the interconnected market, but does not necessarily affect prices over the interconnector. However, the inefficiency could flow through into higher prices bid into the CM since the interconnected capacity initially bears the cost of the inefficiency and factors this cost into its CM bid. Further, it should be noted that GB consumers may bear the cost of any inefficiency that results from a delivery incentive placed on GB generators participating in other CMs in interconnected markets.
- A delivery model places a higher risk on participating interconnected capacity, potentially increasing their bid into the capacity market. Where interconnected capacity is price making and sets the auction clearing price, there is the potential for an overall increase in costs to consumers at the auction.

There are unlikely to be differences in the administrative costs associated with either model. Both have similar metering requirements and, if required, the testing regime is likely to be the same.

5.1.5 Equity

Delivery based models treat interconnected capacity equitably with domestic capacity on a risk-adjusted basis. Because the penalty payments are based on the flow of the interconnector (in either generator or interconnector models) their remuneration reflects delivered energy onto the GB system. The rules, and hence risks placed on interconnected parties are different to reflect the additional delivery risks associated with an interconnector.

Conversely, in an availability model, the interconnected capacity faces only the physical risk. This is the same as domestic capacity, but fails to reflect the ‘implicit subsidy’ to the interconnected capacity. These differences could potentially be internalised through the regulation of the cable. However, delivery models are likely to be viewed as a more equitable treatment of foreign and domestic capacity.

5.1.6 Deliverability

Overall there are some practical difficulties in implementing the options, for example, agreement between TSOs will be required to enable testing and

metering of plant in the interconnected market. However, these do not affect the choice between an availability and delivery model. There does not appear to be a significant difference in the deliverability of either of the models. It is the other building blocks which we go on to assess where there are greater implications for deliverability.

5.1.7 EC Compliance

There are potentially some uncertainties as to the compliance of availability and delivery models with the EC. In particular we have looked at the regulations underlying the Third Energy Package and The Guidelines on Environmental and Energy Aid. One potential issue which is worth further investigation is whether a penalty payment related to the non-flow of an interconnector is viewed by the EC as compatible with the ETM.

The Guidelines highlight the EC preference for not undermining investment incentives and the operation of the IEM, including market coupling. The exact meaning of the guidelines in relation to the choice of availability and delivery is open to interpretation. However, delivery models could be interpreted as having a negative impact on the ETM, given the greater potential for despatch distortions. However, they are likely to be small and infrequent, and could be mitigated through the detailed design of the mechanism. There is also a general trend within Europe towards availability models e.g. the French capacity mechanism is based on availability and an availability model has also been advocated in recent papers by the industry association Eurelectric.

5.1.8 Recommendation between availability and delivery options

There are no clear barriers to specific options created by the EC, although a delivery model potentially raises more questions than an availability model. Following discussions with the EC, should it become clear that availability models are in fact the only compliant approach, there remains a choice as to whether it is based on generating or bidding. Our analysis suggests bidding in the relevant market works best with an availability model.

However, should both delivery and availability options be compliant with the ETM, then there is potentially a security of supply argument for introducing a delivery model whilst the ETM is being fully implemented, even though this may result in small despatch inefficiencies in the interconnected market. There is then a balance to be struck, where applicable, as to whether that delivery model should obligate interconnected generators to generate, or at a minimum bid in the relevant market. There is greater potential to mitigate some of the despatch distortions if they are only obligated to bid. However, it may be harder to identify the additionality that the obligation has created.

The case for a delivery based model diminishes as the ETM is implemented and its efficiency is proven. At which point an availability based model would

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potentially be a more sensible option. Should the ETM be delivered to schedule in 2019-20 this could suggest an availability model is appropriate in the 2015 auction, given the four year lead time between auctions and the delivery year. However, DECC is concerned with the information available in 2015 about how likely implementation by 2019-20 is. Since there remains uncertainty surrounding delivery to this schedule, there may be merit in persisting with a delivery model until certain agreed milestones are met.

5.2 Generator versus interconnector models

Both generator and interconnector options allow payments to flow to the interconnector owner to support investment in interconnectors. The signal is more direct for the interconnector options. Although in theory the interconnector should be able to capture all the CM payments in a generator option e.g. through an implicit or explicit auction, the extent to which it can capture capacity payments will depend on the efficiency of the process.

There could also be different implications for gaming risks. To the extent that there is a specific concern about generator market power in an interconnected market and its potential impact on the GB CM, interconnector options remove direct participation by generators. However, this does not completely remove the problem of generator market power, and it may still be exercised by generators if the interconnector attempts to back-off the risk to generators.

These efficiency effects could lead to differences in the level of investment in interconnectors. However, as we have noted above, any differences could be taken into account through the regulation of the interconnector.

Despatch efficiency is not directly affected by the choice of bidding party. As discussed above, the type of obligation placed on the bidding party is the most important factor for despatch efficiency.

However, by allowing interconnectors to be the bidding party it does mean that they are able to decide how best to manage the ‘delivery risk’ and they may choose to or not to back-off the obligation onto generators. If the probability of a stress event in any given year is low, and the penalties for non-delivery are not sufficiently sharp, the interconnector owner may choose to hold the obligation themselves. This allows them to take all of the upside in most years, but does not deliver the intended security of supply benefits of a delivery option. Full exposure to the penalty risk in a year with a stress event in a purely merchant model may be sufficiently large to disincentivise this behaviour. Regulation could potentially dampen the signal although we think this effect would be weak under Ofgem’s cap and floor regulation.

The cap and floor regulation is designed to provide strong downside incentives and the floor is likely to be set below the level of revenues that investors would target. This suggests that for much of the time the floor would not insulate

interconnector owners from the penalty risk. Only when revenues were at or close to the floor would the regulation dampen the signals from the penalty regime.

Equity is not affected by the choice of bidding party, since equity is really a function of the type of obligation each party faces relative to domestic generation.

Interconnector options are simpler to administer. Generator options create more non-GB parties bidding into the auction and sites to verify, and will require cooperation with the neighbouring TSO on measurement and verification of bidding or generation by contracted generators. Interconnectors also should, in principle, be relatively easily incorporated into the existing design of the capacity auction. Some generator options may require a more complex zonal auction, and potentially raise difficult questions regarding the geographical limits on participation requiring complex de-rating algorithms.

There may be questions for interconnector options due to the unbundling requirements in the Third Package. However, it is unlikely that receiving a capacity payment by an interconnector creates opportunities for market manipulation. From an economic, as opposed to a legal viewpoint, the payments are not in principle different to those received through other auctions in the market.

However, an option which is more consistent with a longer-term Europe-wide solution would bring benefits through reduced costs of transition in future. There has not been a clear statement of a preference by the EC. However, there is a view that in the longer-term an enduring cross-Europe solution is more likely to revolve around generators e.g. the options presented by Eurelectric are based on cross-border implicit auctions for capacity by generators. There could be advantages therefore of moving to a generator led model now to avoid the costs of future change.

The choice between interconnectors and generators is finely balanced. Interconnector options create a more direct investment signal, are simpler and easier to deliver and potentially are less susceptible to gaming. There is the potential, however, that generators are more likely to be part of the enduring solution favoured by the EC reducing the need to change in future if a generation option were selected. As a result we set out recommended designs for both an interconnector and generator options.

5.3 Generator specific filters

Choosing external generators as the CM participant leads to two further questions, or 'building blocks':

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- Should there be limits placed on which generators in the IEM can participate?
- Should interconnector capacity be rationed through an implicit or explicit auction?

5.3.1 Restrictions on the location of generators

In this paper we assessed two potential options related to the restriction of participation in the CM according to the location of generators:

- unrestricted participation by all generators in the IEM; and
- restrict eligibility by de-rating based their likely on the contribution to GB system adequacy.

Both options allow payments to flow to the IC owner to support investment in interconnectors. Assuming a ‘copper plate’ network i.e. allowing unrestricted participation from anywhere within the IEM, could improve competition from foreign capacity, mitigating concerns about market power and gaming. Despatch inefficiencies will remain within the IEM. However, they are likely to be spread more thinly across Europe.

Security of supply is likely to be affected by allowing the participation of generators where there is no reasonable chance that they can influence the flow over the interconnectors into GB. The security of supply benefits that result from incentivising generators to generate are therefore muted.

By de-rating the amount a particular generator can bid in the CM based on their location means that their remuneration is likely to reflect the degree of their realistic contribution to GB system adequacy, which fits with the overarching principle of de-rating based on the primary connection to GB and, therefore, is a fairer treatment of domestic and interconnected capacity.

There is unlikely to be a significant difference in cost to GB consumers. However, there could be an improvement in efficiency due to increased competition. Opening up the CM to all generators in the IEM may affect the allocation of revenue between interconnectors and generators i.e. the outcome of the implicit or explicit auction will be more competitive providing more revenue to interconnectors.

De-rating each application during prequalification on the basis of its specific location would require a complex calculation to be applied to bids and, inevitably, it will not be possible to perfectly de-rate each generator. However, the methodology should ensure bids are only made from plant in regions with a relatively high probability of delivering power in a stress event, minimising the complexity. This complexity is likely to increase the cost of implementing the option.

The EC State Aid guidelines are more unlikely to support participation of all plant in the IEM. They state that a CRM should allow any capacity which can effectively contribute to generation adequacy to participate. Therefore, de-rating capacity based on the complete transmission path to a particular generator is more likely to be consistent with the EC, lead to better security of supply outcomes and represent a more equitable treatment of foreign and domestic generation.

5.3.2 Explicit versus implicit auctions

In theory, both an implicit and explicit auction could lead to the same allocation of revenues between the generators and the interconnector. However, there are a number of reasons why an explicit auction differs from an implicit auction:

- *'Basis risk'* for generators since there is a gap in time between the explicit auction for the 'ticket' to participate in the CM and the CM auction.¹⁹ Because the sale of these rights takes place in advance of the main CM auction they are likely to trade at a discount, reflecting the risk of an unsuccessful CM bid or lower than expected capacity price. In the case of generators that are price takers in the CM, this could be mitigated by the basing the explicit auction not on a price, but instead a percentage of capacity revenue that the generator will share with the interconnector.
- *Greater control* is left with the interconnector owner in an explicit auction to design the auction rules in a way that best supports interconnection, reducing the involvement of DECC. This may allow the auction to be designed in such a way as to best reflect the issues faced on that specific link.

From an efficiency perspective the 'basis risk' is a new risk created by the explicit auctions. Unless this can be mitigated through effective auction design by the interconnector, implicit auctions should be more efficient and provide a stronger signal for investment in interconnection. For the same reason an implicit auction could be more equitable between domestic and foreign generators, because domestic generators do not face this risk.

Generator market power is potentially a problem for interconnectors as it could reduce their share of the capacity market revenues damaging investment incentives in interconnection. However, the choice of auction is unlikely to be able to materially affect the outcome. Where market power exists generators will be able to exercise that power in both an explicit and implicit auction. Although

¹⁹ Although reduced, this issue would arise even if the auction for the ticket and the CM auction were held simultaneously.

they are less likely to be able to affect the overall CM auction price, generators could reduce the share of the CM revenues going to the interconnector.

In the short-term, security of supply should not be affected as the choice of auction will not affect the despatch of generators. However, to the extent that investment in interconnectors is affected there could be worse security of supply outcomes under an explicit auction. Although there are likely to be relatively straightforward ways this could be minimised in the design of the auction, or as we have already noted through the regulation of the line.

The design and management of an explicit auction could be delegated to the interconnector owner who is incentivised to run the auction as a means of earning additional revenues. Whereas the implicit auction must be incorporated into the existing CM auction design by adding in additional bidding zones. This has the potential to create additional complexity and may delay implementation. However, there is also the potential for each interconnector owner to adopt different approaches to explicit auctions, ultimately requiring coordination from DECC.

Even though the design of the explicit auction is delegated to the interconnector owner, some proportion of the cost may still likely to be recovered from GB consumers through regulation of the interconnector. Consumers will directly bear the additional cost of an implicit auction.

In conclusion, an implicit auction, or an explicit auction which mitigates the basis risk, is more efficient and equitable than an explicit auction. Implicit auctions seem more likely to be consistent with the future direction of the EC.

5.4 Interconnector specific filters

Choosing an interconnector as the CM participant leads to two further questions, or ‘building blocks’:

- Should the interconnectors be able to bid into the capacity market or simply receive capacity payments?
- Should the interconnector ‘back-off’ the obligation? And, if so, how?

5.4.1 Is the interconnector bidding or passive?

Investment in interconnector capacity is potentially supported by CM revenues irrespective of whether the interconnector must bid into the CM or may be a passive CM participant. However, if it is assumed that the interconnector is a passive recipient of CM payments, then there is no obligation on the interconnector and it is insulated from any risk of non-delivery both physical and market. This could potentially lead to more inefficient investment decisions, although as has already been discussed this risk can be mitigated by the regulatory regime. Despite this, a passive model still represents an inefficient allocation of

risk due to the removal of the physical availability risk from the interconnector owner, which it is best placed to manage.

Security of supply is likely to be weakened because the interconnector owner does not receive an additional incentive from the capacity market to be physically available, over and above that provided by normal wholesale market revenues. The line may therefore be less likely to be available in a stress event. If this translates into an increase in domestic capacity bought instead, costs for GB consumers could rise. The passive model is also less equitable by favouring interconnected capacity over domestic capacity.

Both options are relatively straightforward to implement. A passive model is likely to be marginally easier. However, it is expected that interconnectors could be integrated into the CM auction as it is currently designed. The main difference would be the additional complexity from pre-qualifying an interconnector for participation in the auction.

If the EC is comfortable with interconnector participation then neither option is likely to face a further barrier from the EC, although it should be noted that a 'passive' option was suggested as only as a potential transitional option by the EC.

In conclusion, ensuring the interconnector bids and receives an obligation is important for security of supply and ensuring the lowest costs for GB consumers. Making the IC a passive participant is unlikely to significantly reduce complexity and deliverability as both options are relatively straightforward to implement.

5.4.2 Interconnector options for 'backing-off' their obligations

The interconnector is able to 'back-off' the CM obligation in the way it chooses and DECC does not have to determine how this should be done. As set out earlier, an interconnector is only likely to want to do this in a delivery based obligation.

A delivery incentive transfers risk from consumers to the interconnector owner the impact of which has been discussed earlier. However, with delivery options DECC is effectively delegating responsibility for managing and sharing risks between the interconnector, generators and the TSOs. The interconnector should in theory be well-placed to judge the most efficient allocation of risk and, if correctly incentivised to do so, should look to pass the risk to the party best able to manage it. As a result, costs for consumers should be minimised. The specific approach to backing off risk adopted by the interconnector is therefore not a real choice for DECC to make.

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6 Recommendations

We have assessed each of the main ‘building blocks’ against the criteria agreed with DECC. This has led to conclusions on a set of design features which form the basis for our recommendations. Inevitably there is not one clear option, but instead a number of options, the final choice of which depends on value judgements to be made by DECC, and interdependencies with the development of European electricity markets.

An important decision, which our analysis suggests is finely balanced, is whether to allow individual external generators to participate directly in the CM auction, or restrict it to interconnector owners instead.

Interconnector options create a more direct investment signal, are simpler and easier to deliver and potentially are less susceptible to gaming. If a generator option is preferred, there are significant complexities that need to be overcome before such an option can be implemented. For example, a generator option requires complex de-rating calculations to be applied to bids from individual generators and the existing GB auction design may need to be extended to include different zones, each with different clearing prices.

However, despite their complexity, generator options are perhaps more likely to be part of the enduring solution favoured by the EC, reducing the need to change in future if a generation option were selected for the GB CM. The value of a generator option will be higher if there is a belief that the EC can implement an EC wide generator solution more quickly. As a result we set out recommended designs for both an interconnector and a generator option.

The conclusions from this analysis for interconnector options are summarised in **Table 7** and for generator options in **Table 8**.

Table 7. Summary of recommendations for design of **interconnector** design options

'Building block'	Summary
Bidding Party	Here, the interconnector may be an active bidder in the capacity auction receiving capacity payments. We do not expect there to be a barrier to the interconnectors receiving a capacity payment as a result of the Third Package. From an economic, as opposed to a legal viewpoint, capacity payments paid directly to an interconnector owner are not in principle different to those received through other auctions already in existence in the market.
Capacity rationing	The capacity of the line should be de-rated to reflect the market as well as the physical risks associated with the interconnector flowing into GB. The payments to the interconnector are therefore based on the likelihood of delivered energy into GB, which is consistent with the treatment of domestic generation in GB.
Basis of the obligation	<p>There are potentially some uncertainties as to the compliance of availability and delivery models with the EC which need to be investigated further. For example, in the State Aid Guidelines a delivery model is more likely to be interpreted as having a negative impact on the ETM, given the potential for despatch distortions, albeit small and infrequent ones. A distortion could arise where the interconnector has 'backed off' the delivery risk to generators, resulting in their desire to generate out of least cost order during a stress event.</p> <p>Assuming a delivery model is compatible with EU state-aid guidelines, then there is potentially a security of supply argument for introducing a delivery model while there remains uncertainty as to whether the ETM will be in place by 2019-20. However, this may result in small and infrequent despatch inefficiencies. These impacts are contingent on the obligation being backed off onto generators, which is not guaranteed. If the probability of a stress event is low and the penalties not sharp, an interconnector may choose to hold the obligation themselves, in which case security of supply benefits disappear.</p> <p>The case for a delivery based model diminishes as the ETM is implemented and its efficiency is proven. At which point an availability based model would potentially be a more appropriate option. This suggests the need for reviewing the chosen option as progress is made (e.g. passing of certain milestones) on ETM implementation.</p>
Risk sharing (penalties)	By placing a delivery incentive onto the interconnector, DECC is effectively delegating responsibility for managing and sharing the risks. The interconnector should in theory be well-placed to judge the most efficient allocation of risk between themselves, generators and the TSOs and therefore, this is not a real choice for DECC to make.

Source: Frontier Economics

Table 8. Summary of recommendations for design of **generator** design options

'Building block'	Summary
Bidding Party	Here, external generators may be allowed to participate on the basis of their realistic contribution to GB system adequacy i.e. generators not immediately adjacent to the GB market should be de-rated further on the basis of the probability of flow across all interconnectors on route to GB during a stress event.
Capacity rationing	An implicit auction, or potentially an explicit auction which mitigates the basis risk, is more efficient and equitable than a pure explicit auction. Implicit auctions are also more likely to be consistent with the future direction of EC market design, if a model similar to that advocated by the industry association Eurelectric is adopted across Europe. An implicit auction will add significant complexity to the existing auction design, and may result in longer development time for this option (compared to an interconnector based option for example).
Basis of the obligation	<p>There are potentially some uncertainties as to the compliance of availability and delivery models with the EC which need to be understood. For example, in the State Aid Guidelines a delivery model is more likely to be interpreted as having a negative impact on the ETM, given the potential for despatch distortions, albeit small and infrequent ones. The distortion could arise because the delivery incentive on interconnected generators from the CM may result in a desire for them generate out of least cost order during a stress event.</p> <p>Assuming a delivery model is compatible with EU state-aid guidelines then there is potentially a security of supply argument for introducing a delivery model whilst the ETM is being fully implemented. However, this may result in small despatch inefficiencies in the interconnected market.</p> <p>There is a balance to be struck, where applicable, as to whether the delivery model should oblige interconnected generators to generate, or at a minimum bid in the relevant market. There is greater potential to mitigate some of the despatch distortions if they are only obliged to bid. However, it may be harder to identify the additionality that the obligation has created.</p> <p>The case for a delivery based model diminishes as the ETM is implemented and its efficiency is proven. At which point an availability based model would potentially be a more sensible option.</p>
Risk sharing (penalties)	In a delivery model failing to deliver on their obligation and hence receive a penalty is not only based on interconnector availability, but also on whether the interconnector flows in the correct direction and at the correct volume during the stress event.

Source: Frontier Economics

Annex 1: International review

Outline of approach to international review

The scope of the international review is defined in terms of:

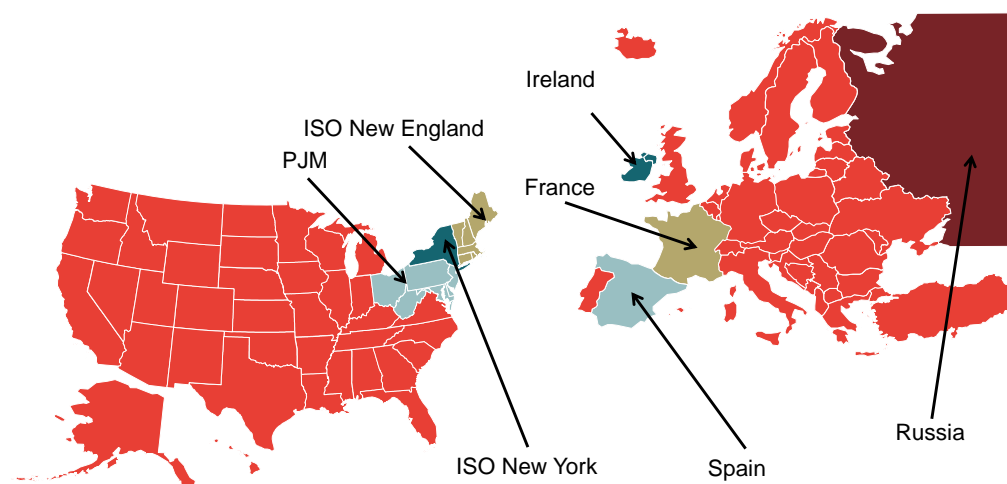
- its geographical coverage i.e. on what basis do we choose to review a particular country/market; and
- the information that is being sought i.e. what questions are we trying to answer.

Geographical coverage

We have focused the review on markets with operational or soon to be implemented capacity markets or capacity payment schemes.

- **In Europe**, Ireland and Spain have a capacity payments scheme and Russia has introduced a capacity market. France is also close to implementing a decentralised capacity market.
- **In the US** capacity markets are more commonplace. We have focussed the review on the major North East markets of PJM, New England and New York.

Figure 9. Mapping out the international review



Source: Frontier Economics

In the case of Europe, our choice of countries has some notable exclusions.

- **Sweden, Norway and Finland all have implemented Strategic Reserves (SR), and Belgium is planning to implement one in 2014.** We have not included these countries in the review. First, they do not allow foreign capacity to bid into their reserves. And second, the issues with a Strategic Reserve are different from those for a market wide capacity mechanism making them less relevant to this discussion. In the case of a SR it is hard to see how foreign capacity can provide a genuinely additional source of capacity, particularly when there are constraints on the interconnector. A shortage in the country with a reserve would push up the price attracting imports, constraining the interconnector. A contracted generator who is sitting outside of the market would not be able to provide any additional security of supply benefit.
- **Germany is also not included.** Germany is still unsure of its position on whether an energy only market is sufficient for ensuring security of supply. They have considered a number of different options for the potential design of a capacity market, for example:
 - A **centralised capacity market**, which is the same high-level approach that has been adopted in GB.
 - A **decentralised capacity obligation** similar to the design proposed in France. Under a decentralised system, market players (e.g. producers, retail suppliers or final consumers) are obliged to contract to secure capacity (kW) in a capacity market. This is in addition to their energy purchases in the energy market.

Questions for the review

This review is aimed at answering a very specific set of questions related to the treatment of interconnected capacity in capacity markets. It is not a review of the capacity markets themselves.

We first need to know whether interconnected capacity is able to participate. If it is then we have investigated the following questions:

- **Who participates in the capacity market?** Do interconnected generation and load participate directly? Or, is it the interconnector directly that participates?
- **How are imports over the interconnector de-rated?** In other words, if the interconnection is 2,000 MW, is there allowed to be 2,000 MW of interconnected generation or less? And, if less, how is the reduction calculated?

Annex 1: International review

- **How is delivery ensured?** Are there arrangements to make sure that if one market is in stress and the other is not, the capacity that has been contracted generates and exports?
- **What is the penalty regime?** How is ‘fulfilment’ of the capacity obligations for interconnected generation measured? What happens and who pays if the obligation is not delivered on.

US case studies

Overview

Many Independent System Operators or Regional Transmission Operators ('ISOs' or 'RTOs') manage reliability of sufficient supply (i.e., resource adequacy) through a centralised capacity market. Load serving entities ('LSEs') are required to demonstrate that they have maintained access to capacity equal to a certain multiple above their peak load such that the planning reserve margin is met. The security standard adhered to in each market is set nationally by the North American Electric Reliability Corporation ('NERC').

Subject to specified conditions (such as the ability to obtain transmission, ability to perform when called upon, and not being committed elsewhere), contracts with imported sources of capacity are generally eligible to help LSEs meet their capacity requirements and receive compensation. Value from the capacity payments paid to imports flows through to interconnectors via the sale of physical transmission rights (PTRs).

LEI has reviewed how imports are treated for capacity purposes in three markets: New England ('ISO-NE'), New York ('NYISO'), and PJM. **Table 9** provides an overview of the key characteristics of these capacity markets.

Table 9. Overview of the key characteristics in selected US capacity markets

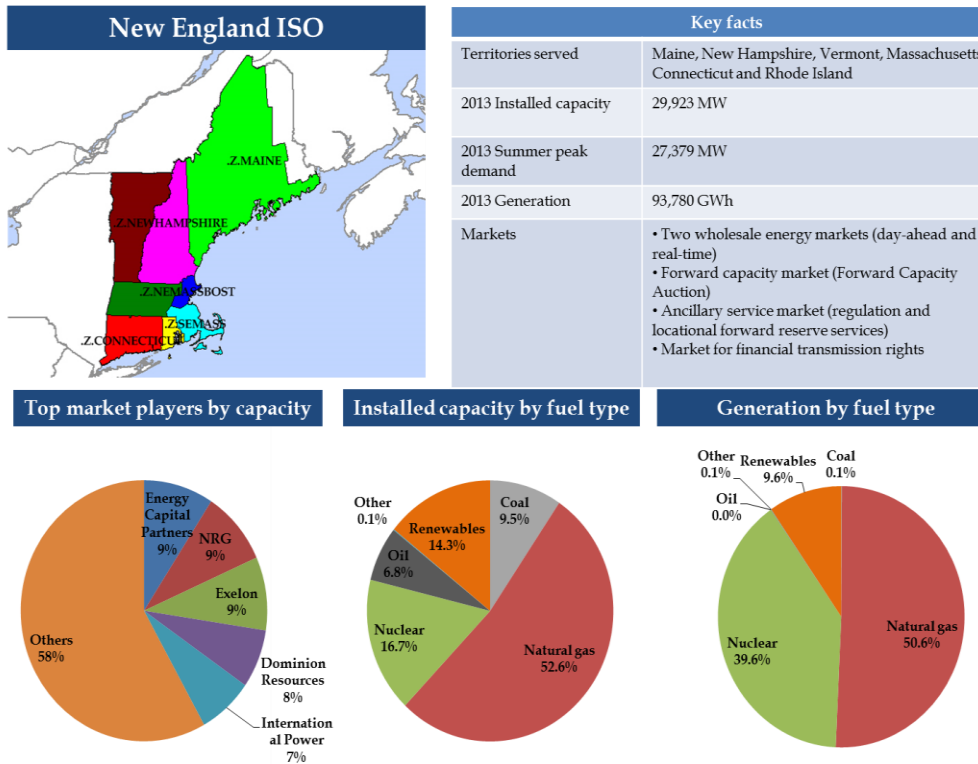
	ISO-NE	NYISO	PJM
Name of mechanism	Forward Capacity Market (FCM)	Installed Capacity (ICAP)	Reliability Pricing Model (RPM)
Demand curve	Vertical (changing to sloping for future auctions)	Downward sloping	Downward sloping
Net CONE	Not resource specific – updated for each auction	Based on peaking plant (gas)	Based on peaking plant (gas)
Market timing (and product term)	3.5 year forward (annual product)	Spot (seasonal and monthly products)	3 year forward (annual product)
Auction/pricing	Descending clock auction	Single round cleared against administratively set locational demand curves	Single round that is cleared administratively
2013 average energy price	\$56.42/MWh	\$52.60/MWh	\$36.74/MWh
Current capacity price	\$7.03/kW-month (delivery year 2017/18)	\$11.30/kW-month (2013 average)	\$1.81/kW-month (delivery year 2016/17)

Source: ISO-NE, NYISO, PJM

New England

The New England Independent System Operator (‘ISO-NE’) oversees and administers the competitive wholesale electricity markets in New England. It operates day-ahead and real-time energy markets as well as a forward capacity market (‘FCM’), an ancillary services market, and a market for financial transmission rights. These markets are coordinated to ensure the supply of reliable power to the region’s 6.5 million households and businesses, or 14 million people in total. ISO-NE spans six states in the northeastern region of the United States (Maine, New Hampshire, Vermont, Massachusetts, Connecticut and Rhode Island). The energy market is currently divided into eight zones mainly based on state boundaries. **Figure 10** shows an overview of the New England market.

Figure 10. Overview of New England Capacity Market



Sources: ISO-NE and third party database provider

ISO-NE uses the FCM to procure installed capacity to meet the Installed Capacity Requirements and ensure reliability of the New England electricity grid. ISO-NE’s FCM is a forward procurement, auction-based locational capacity market. The FCM is built around a Forward Capacity Auction (‘FCA’), the first

US case studies

of which took place in 2008 with the first delivery year in 2010/11. After the initial shorter period, the auctions now take place three and a half years in advance of the delivery period. The market is usually a single price zone, however in some years it is separated out into four separate zones dependent on constraints.

The cost of the FCM is allocated to LSEs based on their peak load. LSEs can contract directly with capacity outside of the FCM. In which case, their share of the total cost is reduced accordingly. The capacity procured through the FCM is reduced accordingly.

For the 2012-13 deliverability period, the Forward Capacity Auction ('FCA') saw 1,900 MW of imported capacity clearing in the market. Québec cleared 1,099 MW and New York cleared 801 MW of capacity. Similarly, in FCA #7, for the 2016-17 delivery period, 1,830 MW of imported capacity cleared in the auction. ISO-NE administers an FCA, as well as Monthly Reconfiguration Auctions ('MRA'), and Annual Reconfiguration Auctions ('ARA') that allow market participants to rebalance their capacity obligations.

Who participates in the capacity market?

Generators, demand resources²⁰ and import resources participate in ISO-NE's FCM. Since the FCM is a forward market, proposed projects, such as generators not yet in commercial operations, can also participate in the auction.

From the point of view of imports, only external generation resources can participate directly in the FCM. Interconnector and external demand resources or load cannot participate in the FCM.

How are imports over the interconnector de-rated?

In New England, capacity resources (i.e. resources that have a capacity supply obligation ('CSO')) clear the market and get paid based on 'qualified capacity'. This is true for both imported and domestic capacity.

Calculations of qualified capacity differ depending whether the resource is an existing one, or a new one. Qualified capacity is based on the summer rating. The summer rating for existing import resources is based on the documents provided by the market participant before the auction. More specifically, the market participant has to provide proof of ownership or direct control over one or more external resources that will be used to back the existing import capacity resource during the capacity commitment period, together with information to establish the summer and winter ratings of the resource(s) backing the import. For new

²⁰ ISO-NE allows both passive demand resources (e.g. energy efficiency projects) and active demand resources (e.g. dispatchable demand response resources) to participate in the FCM.

import resources, if the import will be backed by a single new external resource, the market participant submitting the import capacity must also submit a general description of the project's equipment configuration, including a description of the resource type.

To ensure delivery of imported capacity, ISO-NE limits the amount of capacity from external generators allowed to clear in the FCA to the capacity of the interconnector. The amount of import capacity permitted to clear in an FCA through a particular transmission interface is determined via a planning procedure.²¹ According to the procedure, 'prior to each FCA, Annual Reconfiguration Auction and Annual CSO Bilateral transaction window, the ISO will create an updated network model, which will simulate topology conditions forecasted for the Capacity Commitment Period associated with the auction or transaction window.'²²

Import Capacity Resources are allowed in the FCA up to Transmission Interface Limits minus the tie benefits. The tie-benefits represent the amount of emergency assistance (i.e. balancing resources) that is assumed to be available from New England's neighbouring control areas in the event of a capacity shortage, without jeopardising their reliability.

Transmission Interface Limits will be calculated for internal and external interfaces using the network model, and will be used for calculating the amount of Import Capacity Offers that can be accepted for purposes of meeting capacity requirements. In order to calculate these limits, thermal, voltage and stability studies are updated under a set of criteria and conditions. The criteria used in evaluating the limits include thermal analysis, voltage analysis, stability analysis, and contingency analysis. Using the network model, the transmission interface limit has to meet the above stated criteria under various modelled conditions such as 90/10 load level, base line load power factors, base line generator capability, simultaneous imports from directly connected control areas up to the level of tie benefits, and discrete largest generator outage. This is a technical analysis of the capacity of the interconnector such as dependency of load levels, power transfer across internal and external transmission interfaces, and generation dispatch patterns.

As an example, the 2GW interconnector between New England and Quebec (HQ Phase II tie) is de-rated to 1,400M W for system reasons. Specifically, results of studies performed indicate that under certain system conditions, the

²¹ PP-10 Planning Procedure to Support the Forward Capacity Market, Section 4 - Transmission Interface Limit Analysis.

²² ISO-NE. ISO-NE New England Planning Procedure No. 10 – Planning Procedure to Support the Forward Capacity Market. Section 3 (Submittal, Review and Qualification of Transmission Projects). Page 6.

loss of the HQ Phase II tie under conditions in which a full 2,000 MW of energy was being imported from HQ into NE could cause the bulk power system in the Northeast and Middle Atlantic regions of the U.S. to experience instability, uncontrolled separation or cascading outages, and that these adverse events could also occur at significant lower import levels.

Should there be more Import Capacity Offers below the clearing price in the auction than the de-rated capacity of the interconnector, bids are adjusted pro-rata downwards. During pre-qualification, bidders choose whether they are willing to have their bid reduced pro-rata, and if not they withdraw from the auction at this point.

How is delivery ensured?

This is an availability based model. To ensure an external resource meets its CSO it must bid into the day-ahead and real-time market every hour. In effect, the resource is exclusively available for the New England market. However, no power has to be generated unless ISO-NE dispatches the unit in the energy market.

In order to prevent excessively high bids the New England energy market has a price cap of \$1,000. Resources with a CSO however have their revenue capped at the 'offer threshold' which is below the \$1,000 cap. An external resource with a CSO has its revenue capped, at or below the greater of the offer threshold or the wholesale price of the market in which they are physically located. For example, a unit located within the neighbouring NYISO would have one of its price caps set by NYISO's market price.

Further, to ensure deliverability of import capacity, ISO-NE requires the market participant representing a new import capacity to submit significant documentation prior to bidding in the auction, including:

- documentation of a one-year contract for the entire capacity commitment period, including documentation of the MW value of the contract;
- documentation of a multi-year contract to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the entire capacity commitment period if the import capacity has not cleared in a previous FCA, including documentation of the MW value of the contract;
- proof of ownership or direct control over one or more external resources that will be used to back the new import capacity resource during the capacity commitment period, including information to establish the summer and winter ratings of the resource(s) backing the import; or

- documentation for system-backed import capacity that the import capacity will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load.

Also, for each new import capacity resource, the market participant must specify the interface over which the capacity will be imported.

What is the penalty regime?

Currently, ISO-NE uses an 'availability penalty' regime for capacity resources that are partially or fully unavailable during a shortage event. Penalties are calculated for each shortage event equal to:

$$[\text{Resource's Annualised FCA Payment}] * \text{Penalty Factor} * [1 - \text{Shortage Event Availability Score}]$$

Where:

Penalty Factor = 0.05 for Shortage Events of 5 hours or less. Penalty Factor is increased by 0.01 for each additional hour above 5 hours.

Shortage Event Availability Score is the percentage of the resource's available MW during the shortage hour, subject to adjustments.

The penalty for each resource is subject to a cap on a daily, monthly, and annual basis, based on the amount of payments the resource would receive from the capacity market. The penalties will not exceed 100% of the annual capacity revenue.

Due to the amount of non-performance of capacity resources during shortage hours in recent years, especially during winter when natural gas prices are high and gas-fired generators are facing difficulties in securing gas supply, ISO-NE has been reviewing its capacity market penalty regime.

They argue that capacity providers rarely face financial penalties for failing to perform and so ISO-NE proposed (recently approved by FERC) the Performance Incentive (PI) regime. Under PI, the penalty will be linked to how much energy a resource delivers in real time during very discrete (and unpredictable) shortage events relative to its CSO's share of peak load in that period, and a penalty rate of \$5,455/MWh.

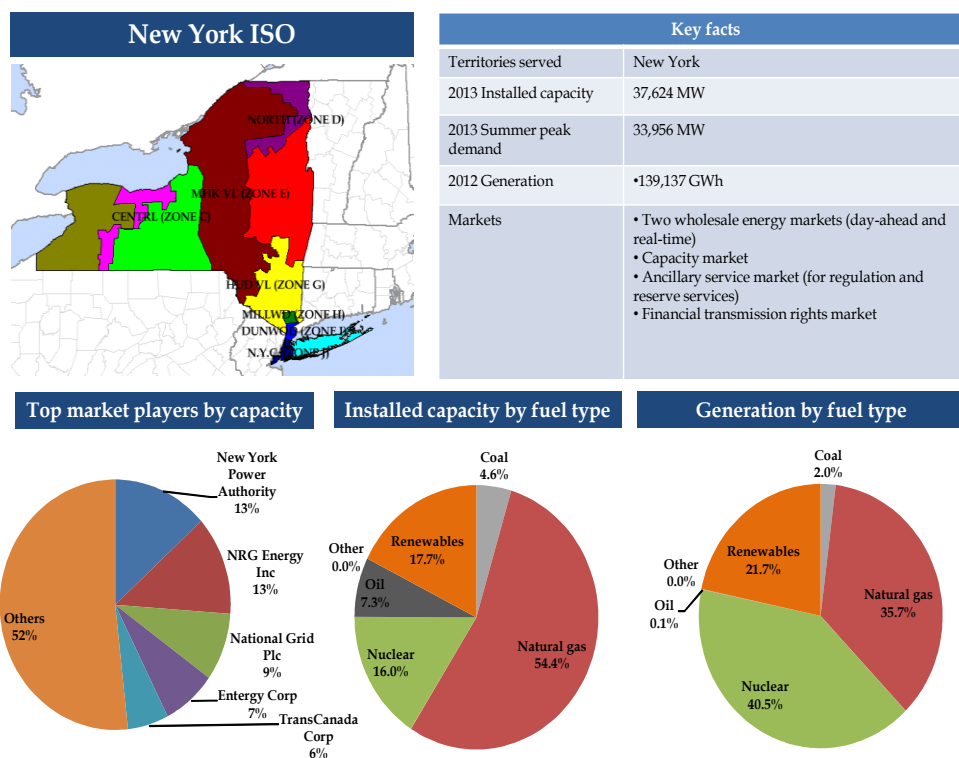
There will be a limit on the penalties but generators may pay penalties that are as much as three times their annual FCA payment. Given the size of penalty and the higher cap, the PI is seen as a more risky performance obligation by most generators.

US case studies

New York

The NYISO is responsible for the reliable operation of the bulk electricity grid of New York State, design and implementation of open and competitive wholesale electricity markets, and energy planning for New York. Currently, the NYISO runs four markets: (i) the energy market (both day-ahead and real-time); (ii) the capacity market; (iii) the ancillary services market (for regulation and reserve services); and (iv) the financial transmission rights market. **Figure 11** presents a snapshot of the NYISO market.

Figure 11. Overview of the New York ISO market



Sources: NYISO, Gold Book and third party database provider

NYISO’s capacity market started in 2000 with the first delivery period 6 months later. It is designed to ensure sufficient resources to meet reserve margins and supplement energy and auxiliary service markets. LSEs can choose the most economic option between purchasing capacity in bilateral transactions, in auctions run by the NYISO, or at the spot auction. NYISO conducts three auctions: a strip, or Capability Period auction, in which unforced capacity may be purchased six months in advance, a forward monthly auction, and a monthly spot

auction. Capacity is also traded bilaterally.²³ The strip and forward auctions effectively target the results of the spot auction. The auctions happen for the next season (prior to winter or summer), for the remaining individual months, and then on a spot basis for the prompt month. The product that is bought is unforced capacity ('UCAP'), and represents the demonstrated capacity of a resource de-rated by historical forced outage rates, which proxy for likely future availability.

Due to transmission constraints within the New York Control Area ('NYCA'), NYISO has historically run three separate geographically distinct capacity market auctions leading to three separate capacity prices. The zones are for New York City ('NYC'), Long Island ('LI'), and NYCA (which is also frequently referred to as the rest of the state or 'ROS'). In 2014, NYISO will add another capacity zone to its auctions. It is expected that this new capacity zone will be known as the Lower Hudson Valley Capacity Zone.

In April 2014, 1,090 MW of external generation were granted capacity obligations in the auction. This compared to a total capacity of 39,529 MW.

Who participates in the capacity market?

Similar to ISO-NE, generators, demand resources, and import resources participate in NYISO's capacity market.

From the point of view of imports, external generation resources participate directly in the NYISO capacity market rather than interconnectors. They receive the capacity price for the market in which they participate i.e. the area where the interconnector enters NYISO.

They must comply with the following key requirements:²⁴

- provide name and location of the resource;²⁵
- demonstrate that the Installed Capacity Equivalent of the amount of Unforced Capacity it supplies to the NYCA will not be recalled or curtailed to satisfy the load of the External Control Area;

²³ The strip auction covers an entire 6 month capability period (summer or winter), and is run at least 30 days prior to the capability period. The monthly auction is run at least 15 days prior to a month, while the spot auction is run 2-4 days prior to the month. Note that in the spot auction, the NYISO purchases capacity for the LSEs that have not purchased sufficient capacity.

²⁴ NYISO. *ICAP Manual. Section 4.9.1.*
<http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf>

²⁵ Control area-backed capacity imports are allowed to participate in the NYISO capacity market.

- provide documentation of a Dependable Maximum Net Capacity ('DMNC') test, or its equivalent;
- provide evidence that the capacity has not been sold elsewhere;
- provide documentation that satisfies the maintenance and scheduling requirements;
- submit data detailing expected return dates from full or partial outages;
- submit operating data for the prior 17 months; and
- demonstrate that the Installed Capacity Equivalent of the amount of Unforced Capacity it supplies to the NYCA is deliverable to the NYCA i.e. that it has a physical transmission right.²⁶

How are imports over the interconnector de-rated?

External generation resources are treated the same way as internal generation in terms of how the unforced capacity (UCAP) is calculated. UCAP is used to represent the demonstrated capacity of a resource in the capacity market. Capacity is de-rated by historical forced outage rates, which proxy for future availability. Note that NYISO determines specific de-rating factors for renewables – on shore wind is de-rated to 10% in the summer and 30% in the winter in the NYCA, while solar capacity is de-rated depending on tilt angle (if fixed), while tracking solar arrays are de-rated to 46% in summer and 2% in the winter.²⁷

Furthermore and similar to ISO-NE, NYISO establishes the maximum installed capacity that can be supplied by each neighbouring control area, as part of the process to set the NY Installed Reserve Margin ('IRM').²⁸ In order to set the amount, the NYISO performs simulations where external installed capacity is varied. The maximum external installed capacity for each neighbouring control area is reduced in direct proportion until the Loss of Load Expectancy ('LOLE') matches the base case.

For controllable transmission projects, unforced capacity deliverability rights ('UDR') are assigned. The amount of UDR for each project is assigned by the

²⁶ External resources will be subject to deliverability tests in which the participant must demonstrate unforced transmission rights.

²⁷ NYISO. *ICAP Manual. Section 4.5.*
<http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf>

²⁸ NYISO. *ICAP Manual. Section 2.7.*
<http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf>

NYISO based on ‘transmission capability, reliability, availability of the facility, and appropriate NYSRC reliability studies.’²⁹

How is delivery ensured?

Similar to ISO-NE this is an availability based model. To ensure an external resource meets its obligation it must bid into the day-ahead market every hour. In effect, the resource is exclusively available for NYISO market. However, no power has to be generated. There is no price cap in the NYISO market.

One of the requirements for external resources to participate in the NYISO capacity market is that they must demonstrate:

*...the Installed Capacity Equivalent of the amount of Unforced Capacity it supplies to the NYCA will not be recalled or curtailed to satisfy the Load of the External Control Area, or that the External Control Area in which it is located will afford NYCA Load the same curtailment priority that it affords its own Control Area Native Load.*³⁰

In short, this arrangement ensures that the external resource will still generate and export, and will not be curtailed as a first option to meet load requirements in the other market.

What is the penalty regime?

If energy associated with external unforced capacity is not offered i.e. made available to the NYCA in every hour, the supplier will face a deficiency charge.³¹ If the full amount is not certified or offered, the penalty is that the supplier pays the NYISO 1.5 times the spot auction clearing price, multiplied by the capacity committed.³²

²⁹ NYISO. *ICAP Manual. Section 4.14.1.*
<http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf>

³⁰ NYISO. *ICAP Manual. Section 4.9.1.*
<http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf>

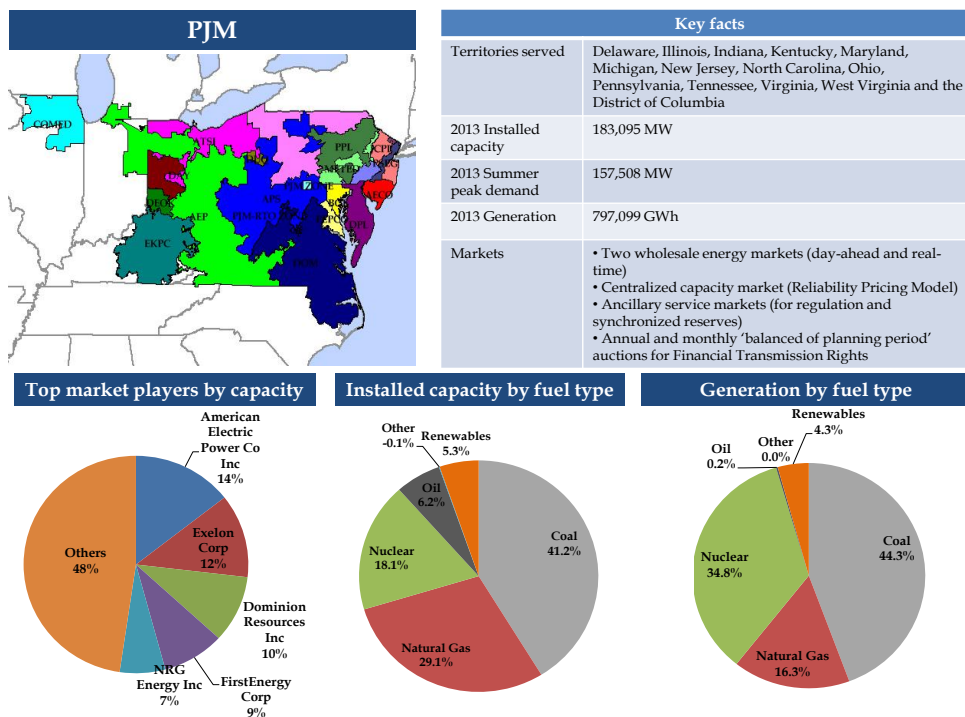
³¹ NYISO. *ICAP Manual. Section 4.9.4.*
<http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf>

³² NYISO. Attachment S. Section 25.7.11.1.3
<http://www.nyiso.com/public/webdocs/markets_operations/documents/Tariffs/OATT/Attachments/att_s.pdf>

PJM

The PJM Interconnection is a Regional Transmission Operator (RTO) that manages grid reliability and wholesale electricity markets for 13 states and the District of Columbia. PJM covers all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM operates two wholesale energy markets – a day-ahead and a real-time market, both of which are based on the Locational Marginal Pricing (‘LMP’) model.³³ It also has a centralised capacity market called the Reliability Pricing Model (‘RPM’), ancillary service markets (for regulation and synchronised reserves), and annual and monthly ‘balance of planning period’ auctions for Financial Transmission Rights (‘FTRs’). **Figure 12** presents an overview of the market.

Figure 12. Overview of the PJM market



Sources: 2013 PJM State of the Market Report and third party database provider.

PJM’s RPM was implemented in 2007 with delivery 3 years later. It is designed to ensure availability of resources that can be called upon to ensure the reliability of

³³ PJM was the first market to institute LMPs for energy.

the electric grid. The RPM has a multi-auction structure designed to procure resource commitments to satisfy the region's unforced capacity obligation through a Base Residual Auction ('BRA')³⁴ and Incremental Auctions.³⁵ The BRA occurs three years in advance of the annual deliverability period. In addition to the capacity price for the whole of the PJM (also known as the PJM RTO), the RPM also has locational capacity pricing, which allows Locational Deliverability Areas ('LDAs') to reflect the need for capacity in import constrained areas. LSEs can either procure capacity through the RPM, or alternatively they can demonstrate their capacity plan for that delivery year separately.

Based on the 2013 auction (for delivery in 2016), a total of 7,483 MW of imports were procured. This is 4% of the total capacity that cleared during the auction.

Who participates in the capacity market?

Like ISO-NE and NYISO, generators, demand resources or load, and import generation resources participate in the RPM. Existing and planned generation resources outside of PJM (imports) can participate in PJM's RPM auction and receive the PJM RTO price (even if the interconnector enters the PJM in another more constrained LDA). They also need to demonstrate a request for Firm Transmission Service from the resource to and into PJM and meet the other requirements set by PJM Manual 18:³⁶

- Provide an indication of the intended ATC path to deliver the existing external capacity into PJM (firm transmission service from the unit to the border of PJM and generation deliverability in PJM must be demonstrated by the start of the delivery year);
- provide twelve months of NERC/Generating Availability Data System ('GADS') unit performance data to establish its forced outage rate (EFORd) and the unit's operating and maintenance information;
- provide results of winter and summer testing confirming the unit's capability;
- submit a letter of non-recallability assuring PJM that the energy and capacity from the unit is not recallable to any other control area;

³⁴ BRA is held every May, three years in advance of the delivery year.

³⁵ Incremental Auctions are usually conducted after the BRA to procure additional resources due to changes in committed resources or increased unforced capacity obligations.

³⁶ See *PJM Manual 18: PJM Capacity Market*, Section 4.2.2 (Existing Generation Resources-External) for more information.

- external capacity without firm transmission must establish an RPM credit limit prior to an RPM auction;
- create a communication path between the PJM dispatchers and the operator of the unit; and
- for planned generation resources, in addition to the above, a resource provider must demonstrate that it has executed an interconnection agreement with the transmission owner of the transmission facilities or distribution facilities to which the resource is being connected.

Existing generation located outside the PJM region that is offered into an RPM auction is treated in the auction process as capacity delivered into the unconstrained area of the RTO.

How are imports over the interconnector de-rated?

Similar to ISO-NE and NYISO, external generation resources are treated in the same way as internal resources in terms of how they are de-rated in the RPM. Capacity supply is determined as unforced capacity ("UCAP") which is installed capacity ("ICAP") rated at summer condition that is not on average experiencing a forced outage or forced de-rating. UCAP is calculated as follows:

$$\text{UCAP} = \text{ICAP} \times (1 - \text{Equivalent Demand Forced Outage Rate or EFORD})$$

Where:

ICAP is the value of a unit based on the summer net dependable rating; and

EFORD is a measure of the probability that a generating unit will not be available due to forced outages or forced de-ratings when there is a demand on the unit to generate.³⁷

The EFORD of a unit is based on forced outage data over the period from October to September. If a unit does not have a full one-year history of forced outage data, the EFORD will be calculated using class average EFORD, which PJM posts on the internet by November 30 before the delivery year.

How is delivery ensured?

A resource committed to RPM is expected to be able to deliver unforced capacity during the delivery year that is equal to or greater than the unforced capacity committed through RPM Auctions. This means a generator must bid into the energy market below the \$1,000 price cap in every hour. Again this is a measure of availability rather than actual energy delivered.

³⁷ PJM. *Manual 18: PJM Capacity Market*. Section 4.2.5.

In addition, before an external generation can participate in the capacity market, the resource provider must provide a letter of non-recallability assuring PJM that the energy and capacity from the unit is not recallable to any other control area.³⁸

Lastly, PJM filed on November 29, 2013 a proposal with FERC to limit the amount of capacity from external resources that can be imported into the PJM region, effective January 31st, 2014.³⁹ PJM noted that while its RPM recognises locational constraints that limit the delivery of capacity within PJM, it does not do so for locational constraints from outside the region.

Currently, there are no capacity import limits in PJM's RPM auction clearing rules, and there is evidence of speculative bidding. This involves submitting a bid into the BRA which is not linked to a physical resource, or one associated with an underlying resource (e.g. transmission investment) which itself has no degree of certainty that it can be available in the delivery year. The economic loss of a bid is likely to be low, and there is a high probability of profit. The capacity obligation can be sold back into the IA where prices have usually been higher.

PJM has tried to address this issue by reviewing requests for firm transmission service into PJM. However, some of the capacity import offers may be assuming firm transmission that will eventually prove uneconomic. Furthermore, PJM worries that none of the capacity offers are taking into account the risk of firm transmission curtailments. As a result, PJM believes that at present, offers from external resources are being submitted and cleared in the RPM auctions above the level that can be reliably delivered to PJM as capacity.

The PJM RTO capacity price has declined by more than 50% from \$136/MW-day in the 2015/2016 BRA to \$59.37/MW-day in the 2016/2017 BRA due, in part, to the 90% increase (3,546 MW) in import capacity that cleared in the market.

Because of all of these concerns, PJM proposes to impose a capacity import limit which will be modified annually and will be set using appropriate modelling and application of engineering judgment.^{40, 41}

³⁸ PJM. *Manual 18: PJM Capacity Market*. Section 4.2.1.

³⁹ PJM. *PJM's Application to Limit the Amount of Capacity from External Resources that PJM can Reliably Import into the PJM Region* (FERC Docket No. ER14-503-000). November 29, 2013. Available online at <http://www.pjm.com/~media/documents/ferc/2013-filings/20131129-cr14-503-000.ashx>

⁴⁰ 5 zones have been identified for the capacity import limit: North (NYISO and ISO-NE), West 1 (East and West Midcontinent ISO, Ohio Valley Electric Corporation), West 2 (MISO Central and South), and South 1 (Tennessee Valley Authority and Louisville Gas and Electric Co), and Virginia-Carolinas reliability subregion.

⁴¹ PJM provided limited information with regards to the type of modeling it will use to determine the capacity import limits in its November 2013 filing.

PJM allows exceptions to the capacity import limit as long as three conditions are met:

- at the time of the offer, the external resource has confirmed firm transmission;
- it has met all requirements to be a ‘pseudo-tied’ resource in PJM (e.g, a generation resource that is located physically in one reliability authority area but treated electrically as being in another reliability authority area and is subject to the dispatch of the second reliability authority); and
- it has agreed to be subject to the same ‘capacity must offer’ requirement as PJM internal resources.

This proposal is still being reviewed by FERC.⁴²

What is the penalty regime?

Similar to ISO-NE and NYISO, PJM imposes deficiency charge penalties to the external generation resource for failure to meet generation resource commitments to be available to the PJM market at all times. In other words, PJM imposes penalties for non-availability. A daily capacity resource deficiency charge will be assessed on the commitment shortage when a resource owner’s daily RPM generation resource position is less than its daily RPM resource commitment. The Daily Capacity Resource Deficiency Charge is calculated as follows:

$$\text{Daily Capacity Resource Deficiency Charge} = \text{Daily Deficiency Rate} \times \text{Daily RPM Generation Shortage}$$

Where:

Daily Deficiency Rate (in \$/MW-day) is equal to the weighted average resource clearing price + the higher of the two: (i) 0.2 x weighted average resource clearing price or (ii) \$20/MW-day.

Daily RPM Generation Shortage is calculated as daily RPM resource commitments⁴³ minus daily RPM generation resource position.

⁴² On January 28, 2014, FERC issued a deficiency letter to PJM stating that it needs to provide additional information on its filing. In particular, FERC wants to know how PJM arrived at its proposed capacity limits and more details on how generators can be exempted. PJM responded to FERC on February 21, 2014 and asked FERC to approve the proposal by April 21, 2014.

⁴³ Or, the UCAP cleared in the market.

European case studies

Ireland

The Single Electricity Market (SEM) has, since Go Live in November 2007, remunerated generators in part through a capacity mechanism. Owing to the need to ensure compliance with the ETM, the SEM will be redesigned. The draft design (June 2013) is likely to introduce a capacity market, with the specific design choice of a reliability option. There is no decision yet on how or whether foreign plant can participate.

The SEM can be described as a mandatory wholesale market i.e. electricity generators, with over 10 MW capacity, are obliged by law to sell electricity into a single pool for the island of Ireland. Generators must sell electricity to the pool at the short-run marginal cost of producing each unit of electricity (€/MWh).⁴⁴

In addition to the wholesale price generators also receive a capacity payment. This is paid simply for being available, irrespective of actual generation. The capacity payments are aimed at encouraging availability close to real time as well as allowing generators to recover their fixed costs (i.e. the fixed cost of the peaking unit of the most cost efficient plant).^{45 46}

The generators receive the following payments:⁴⁷

- System Marginal Price (SMP) for their scheduled despatch quantities; and
- Capacity payments for a forecast availability and for actual availability.

This payment structure has the potential to distort flows over the interconnector. i.e. flows are not driven by wholesale price differences alone. For example, in a scenario where the wholesale price is higher in GB than SEM, the interconnector could still flow towards Ireland. This is because the additional capacity payment paid on the flow into Ireland makes it more profitable to flow out of GB. This is a further reason why the Irish model is not directly applicable to the GB situation.

⁴⁴ <http://www.aireland.com/the-single-electricity-market/wholesale-electricity-market.746.html>

⁴⁵ <http://www.esbi.ie/news/pdf/White-Paper-Integration-Electricity-Markets.pdf>

⁴⁶ <http://www.aireland.com/the-single-electricity-market/capacity-payments-mechanism-cpm.751.html>

⁴⁷ <http://iea-rettd.org/wp-content/uploads/2011/10/Ireland-Country-Report.pdf>

Including interconnected capacity

Interconnector users are able to participate in the capacity payment mechanism.⁴⁸ Not the interconnector owner itself. The interconnected generators receive a payment paid out on the basis of their eligible availability in each trading period regardless of the technology type or technical characteristics such as likelihood of outages. The de-rating is set by the generators when they submit their individual availability⁴⁹. The total interconnector users' availability cannot be higher than the available transfer capacity of the interconnector.

The Total Capacity Payment paid to the market is a function of an estimate of the MW required and the annual cost of new entry for a peaking plant (which is determined net of any expected ancillary service and energy market revenues).

Figure 13. Calculating the total capacity payment pot in SEM

$$\begin{array}{ccc}
 \text{Total Capacity payment} & = & \text{Total MW Required} \\
 & & \text{(based on demand forecast, calculated by EirGrid)} \\
 & & \times \\
 & & \text{Annual Cost of Peaking Plant} \\
 & & \text{(based on efficient new peaking plant, calculated by the regulator)}
 \end{array}$$

Source: Frontier Economics

How is delivery assured?

Capacity payments are made to Generator Units for the supply of availability. The treatment is the same for Irish generators and GB generators. As described in the Trading and Settlement Code, there are three parts to capacity payments:

- fixed part (based on annual load forecast);
- ex-ante variable part (based on ex-ante loss of load probability); and
- ex-post part (based on ex-post loss of load probability).

These are currently set at 30%, 40% and 30% respectively. When a generator is available i.e. it bids into the SEM, it receives all three payments. If it fails during a half-hour trading period, it will only receive the fixed and variable payments, it will not receive the ex-post payment. It will also not receive the ex post payment

⁴⁸ Appendix M of Trading and Settlement Code, <http://www.sem-o.com/MarketDevelopment/Pages/MarketRules.aspx>

⁴⁹ What Role Does a Capacity Payment Mechanism Play in Ensuring Adequate Generation in Electricity Markets? An Irish Perspective, Hannon (2010).

for the period of time in which it is on outage. Payments resume once the outage has been resolved and it has been tested

What is the penalty regime?

The obligation is not on energy, and is paid day by day. When the generator declares itself available by bidding into the SEM, it receives a payment. If a generator fails to be available during a trading period, it will only receive the fixed and ex-ante variable payments for that period.

France

France has decided to implement a capacity mechanism, which is due to operate from 2016. This will be a decentralised capacity market operated by the TSO for France, RTE. France has determined that it does not need to notify its capacity mechanism to the EU for the purposes of obtaining State Aid clearance. The details of the rules for the French CRM have recently been published, in which they state that the proposed mechanism meets EU requirements.

There is no resolution to the debate as to how exactly interconnected capacity is to be included. But France has set out a roadmap to introduce it and believes that it will be possible to achieve 'explicit' participation of interconnected capacity. RTE have launched a ten month consultation.

Whilst we do not know what the final treatment will be for interconnected capacity, the French CRM will factor in the capacity value of interconnections to its capacity calculations i.e. 'implicit' participation of interconnected capacity. It will do this by scaling down the amount of capacity procured to reflect the contribution of interconnectors to security of supply.

The amount of capacity procured through the CRM is set with reference to peak consumption in the event of a cold wave, adjusted for a security coefficient. The security coefficient reflects:

- the contribution of interconnectors to security of supply; and
- a margin to reflect residual risk (other than related to a cold wave).

This aspect of the CRM features in the Decree from December 2012 that defines the basic design of the French CRM. This feature has been confirmed in the recent documentation concerning the rules.

Although RTE has not set out the final details, it has set out its initial thinking on principles for the 'explicit' participation of interconnected capacity, as follows:

- The arrangements should not undermine the progress made to date in terms of operation and the efficiency of the internal market for energy.
- The arrangements should not undermine the split of competences as per the Lisbon Treaty and in particular the fact that there are national definitions for security of supply.
- The economic rationale for explicit participation relies on actual contribution to security of supply, which in turn rests on the capacity being:
 - available (and the possibility to monitor that availability in times of stress);

- compatible with the interconnector capacity; and
- able to contribute to domestic security of supply in the event of shortage in several countries at the same time.

As a result RTE has set out some potential conditions for a target solution:

- Condition 1 - There is no need to harmonise the criteria for security of supply across member states.
- Condition 2 - Capacity bookings on the interconnector are not required.
- Condition 3 - The volume of capacity that can participate from different locations should be bounded by the physical import capacity from that location in peak periods.
- Condition 4 - A cross-border certification/monitoring arrangement should be set up (this might include a ‘conversion’ mechanism that sets how many units of capacity from country X is equivalent to a unit of capacity in France in terms of contribution to security of supply).
- Condition 5 - Crisis management arrangements should be made to deal with coincident stress events in neighbouring markets.

Given the amount of coordination these conditions imply (conditions 4 and 5 in particular), RTE suggests an interim solution might be a requirement that foreign capacity participates in the French balancing mechanism. Alternatively, where the foreign country has set up a CRM, France/RTE could enter a mutual recognition agreement with it. During this interim phase interconnectors on different borders could be treated differently i.e. ‘implicit’ and ‘explicit’ participation co-exist, with explicit participation perhaps more likely initially with Germany.

Spain

Following market liberalisation in 1997 Spain introduced a capacity payments scheme. A fund was created from a levy on consumers and distributed to generators based on their peak availability. In 2007 this was split into two separate payments: the investment incentive and the availability incentive. The former has the objective of incentivising sufficient new entry and the latter sufficient capacity availability.

- The investment incentive consists of an annual payment to generators of 26,000 €/MW during the first 10 years of the plant's life.
- The availability incentive paid to a plant is equal to its net capacity x 5,150 €/MW x a factor that depends on the technology.

This factor is equal to 0.912 for coal plants, 0.913 for CCGTs, 0.877 for fuel oil plants and 0.237 for big hydro and pumped storage. In order to receive the availability payments corresponding to a given year plants have to prove an average available capacity equal to 90% of their net capacity in the period that includes the hours in which demand is typically the highest in the day (not taking planned interruptions into account). The system operator is in charge of deciding if a plant meets the availability requirements to receive the incentive.

Only the installations listed in the Spanish register of installations are able to participate. This limits the regulation only to Spanish installations, meaning that foreign capacity is not allowed.

However, when the Transmission System Operator (REE) evaluates future demand they do take into account interconnection. Spain is interconnected to three countries, France, Portugal and Morocco. The respective import capacities are 1,200 MW, 2,100 MW, and 600 MW. The export capacities are 1,000 MW, 2,700 MW and 900 MW respectively. Since 2010 Spain has been a net exporter of electricity: there were 8 TWh of exports in 2010, 6 TWh in 2011-12 and 11 TWh in 2012-13. Consequently, in the analysis of capacity requirements in 2013-14 it is assumed 1.2-1.9 GW (25-40% of total interconnector capacity) will be exported at peak demand. For subsequent years the analysis assumes the interconnectors will be at zero balance.

Russia

The introduction of the Russian Capacity Market responded to concerns over the need for investment in new capacity at a time when the Russian wholesale electricity market was undergoing extensive reforms (privatisation and liberalisation). The capacity market creates a stable revenue stream contributing to the fixed costs of existing plants and new investments. It was introduced when liberalisation of the market began in 2006 and was gradually implemented to become fully operational in 2011.

There are three electricity lines linking the Finnish and Russian electricity market with an overall capacity of 1,400 MW.⁵⁰ The electricity interconnectors are managed and owned by the Finnish Electricity Transmission company Fingrid. However, the use of interconnector capacity is assigned to the Russian state-owned company InterRAO.

Currently only exports are possible from Russia to Finland. The interconnector has never been used to transport electricity from Finland to Russia due to technical restrictions. But, we expect that two-way trading will soon be possible after an upgrade on one of the interconnected lines⁵¹.

Interconnected capacity in Finland can participate in theory in the Russian capacity market. However, even with two-way trading, it may not be possible since in order to sell capacity in the Russian capacity market, Finnish generators must always be able to deliver the volume of electricity in its obligation and participate in Russian operational and/or spinning reserves.

Should these rules change in future it may become easier for Finnish capacity to participate in the Russian capacity market. In this case, interconnected capacity would compete with existing generation capacity at the auction (there are separate payments for new and existing capacity). But, capacity payments to interconnected capacity, in contrast to generation, are based on availability rather than actual delivery.

Even without the participation of interconnected capacity from Finland the Russian capacity market does have a negative impact on the efficient use of the interconnector, as recently highlighted by ACER. Flows from Russia to Finland

⁵⁰<http://www.fingrid.fi/en/powersystem/general%20description/Nordic%20power%20system%20and%20interconnections%20with%20other%20systems/Pages/default.aspx>

⁵¹<http://www.bloomberg.com/news/2012-12-04/finland-to-test-first-power-exports-to-russia-next-year.html>

only occur when the price in Finland compensates for a ‘capacity fee’ on exports from Russia. This will lead to underutilisation of the interconnector.

Exports are treated as if they were load. To export electricity to a neighbouring country during peak hours, the exporter must buy capacity from the capacity market. As a result there is an additional direct cost which Russian exporters need to take into account when deciding whether to export or not. The exporter has to notify the SO about its planned capacity export (or maximum hourly electricity export during peak hours) two months before the auction.

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