Title: Participation of Interconnection in the Capacity Market	**Impact Assessment (IA)**
	Date: 19/1/2015
IA No: DECC0183	**Stage:** Final
Lead department or agency: DECC	**Source of intervention:** EU
	Type of measure: Secondary legislation
	Contact for enquiries: Janina Ketterer janina.ketterer@decc.gsi.gov.uk
Summary: Intervention and Options	**RPC:** N/A

Cost of Preferred (or more likely) Option				
Total Net Present Value	**Business Net Present Value**	**Net cost to business per year** (EANCB in 2009 prices)	**In scope of One-In, Two-Out?**	**Measure qualifies as**
			No	Tax and Spend

What is the problem under consideration? Why is government intervention necessary?

Investors are concerned about 'missing money' weakening the incentive to invest in generation capacity in an energy-only market. As the sector decarbonises, uncertainty about running hours increases, making generators more reliant on very high prices during periods of scarcity to recover their fixed costs. As a result of this increased uncertainty, an energy-only market may no longer incentivise sufficient capacity to meet demand. The Capacity Market addresses this market failure by providing steady payment for capacity.

The introduction of the Capacity Market is likely to lower the domestic electricity wholesale price and potentially affects incentives for additional investment in interconnection, who cannot currently participate in Capacity Market auctions. The rationale for interconnector inclusion in future Capacity Market auctions is, in particular, to correct for this potential impact. In addition, participation of interconnectors featured prominently in the European Commission's State Aid decision for the Capacity Market, which includes a commitment from the Government to include interconnectors for auctions taking place from 2015 onwards.

What are the policy objectives and the intended effects?

The high level objectives of including interconnectors in the capacity market are:

- **Security of Supply**: to incentivise sufficient investment in capacity to ensure security of electricity supply;
- **Cost-effectiveness**: to incentivise in lowest cost capacity;
- **EU internal energy market**: Commitment to the European Union internal energy market and the State Aid rules.

What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)

This Impact Assessment provides further evidence supporting the design choices with respect to treatment of interconnectors in the Capacity Market. This incorporates several elements: bidding party (interconnector- versus generator-led model); nature of the capacity obligation (delivered energy versus declared availability); penalty regime; de-rating methodology and process; and agreement length.

The lead policy option is a delivered energy model whereby the interconnector itself is the Capacity Market participant and eligible for rolling annual agreements. The interconnector will be de-rated to the realistic long run expectation of the contribution at times of stress, receive the same clearing price and hold the same obligations as other participants.

Will the policy be reviewed? It will be reviewed. **If applicable, set review date:** See Section 10

Does implementation go beyond minimum EU requirements?			**N/A**		
Are any of these organisations in scope? If Micros not exempted set out reason in Evidence Base.	**Micro** No	**< 20** No	**Small** No	**Medium** No	**Large** No
What is the CO2 equivalent change in greenhouse gas emissions? (Million tonnes CO2 equivalent)			**Traded:**	**Non-traded:**	

I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed by the responsible Minister: Matt Hancock Date: 16/1/2015

Summary: Analysis & Evidence

Lead Policy Option

Description: Participation of Interconnection in the Capacity Market

FULL ECONOMIC ASSESSMENT

Price Base	PV Base	Time Period	Net Benefit (Present Value (PV)) (£m)		
			Low: N/A	High: N/A	Best Estimate: N/A

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low	N/A		N/A	**N/A**
High	N/A	-	N/A	**N/A**
Best Estimate	N/A		N/A	**N/A**

Description and scale of key monetised costs by 'main affected groups'

The evaluation of costs and benefits of interconnector participation is undertaken though a qualitative analysis (Section 7), supported by financial and electricity dispatch modelling (in Section 6). The latter quantitative analysis looks at the likely impacts on the auction clearing price. It is therefore complementary to previous Impact Assessments but does not draw conclusions on the monetary and non-monetary effects of the wider Capacity Market intervention itself, including the impact on consumer bills.

Other key non-monetised costs by 'main affected groups'

Including interconnectors in the Capacity Market has a number of significant non-monetised costs and benefits (discussed further in Section 7). We have evaluated different options for how interconnectors could be included in the Capacity Market. We have applied success criteria, such as impacts on security of supply, cost to GB consumers, minimisation of future transition costs and compatibility with EU policy, to ensure the policy option chosen promotes competition and efficient investment signals across GB and non-GB generators. This should minimise costs for the main affected groups.

Regardless of the impact on clearing prices, the participation of interconnectors will increase the amount of capacity to be procured through the Capacity Market. This increases the overall policy cost, to the extent that buying more capacity is not offset by a corresponding decrease in the clearing price.

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low	N/A		N/A	**N/A**
High	N/A	-	N/A	**N/A**
Best Estimate	N/A		N/A	**N/A**

Description and scale of key monetised benefits by 'main affected groups'

Please see above.

Other key non-monetised benefits by 'main affected groups'

The participation of interconnected capacity in the Capacity Market is expected to increase the pool of competitors and can help to achieve a lower clearing price, if it causes more interconnection to be built or if interconnectors put pressure on the marginal plant to bid more competitively in the Capacity Market auction. The quantitative analysis in Section 6 expands on these points.

Key assumptions/sensitivities/risks Discount rate (%) N/A

The first capacity auction, for GB generation only, has been run in December 2014, with a delivery year of 2018/19. The results of this auction have not yet included in the electricity dispatch modelling in this IA.

Currently, it is not possible to endogenously model interconnector investment decisions within the Dynamic Dispatch Model and any interaction between Capacity Market revenues and interconnector build. Therefore, the modelling assumes that the interconnector build is exogenous across the range of scenarios.

The central scenario presented in this analysis continues to use the interconnector capacity assumption of 3.75GW for existing capacity, which corresponds to 1.5GW de-rated capacity. For the reference case, we have updated the assumption for the future interconnection capacity and estimate that 5.4GW of de-rated capacity is available from interconnection by 2030. A sensitivity analysis of this assumption is conducted, as outlined in Section 6.

BUSINESS ASSESSMENT

Direct impact on business £m:			In scope of OIOO?	Measure qualifies as
Costs: N/A	Benefits: N/A	Net: N/A	No	N/A

Evidence Base (for summary sheets)

Contents

1 Overview

1.1 The Capacity Market has been implemented to incentivise sufficient reliable capacity (both supply and demand side) to ensure a secure electricity supply.

1.2 Through the first auction in December 2014, the Government has procured 49.26GW[1] of capacity at a clearing price of £19.40/kW, at a total cost of £0.96bn (all in 2012 prices).[2] Our latest estimate for the average impact of the CM on consumer bills up to 2030 is £2 between 2016 and 2030 (again in 2012 prices).[3]

1.3 Interconnection to other electricity markets can contribute to secure electricity supply in GB by allowing other markets to supply electricity at times of stress and potentially reduce the need to build domestic backup plant. Allowing interconnectors to participate also enables greater competition in the auction and ensures that the Capacity Market does not affect interconnector investment signals.

1.4 This Impact Assessment provides an update to the analysis of the Capacity Market and focuses on the inclusion of interconnectors. It supports the laying in Parliament of the Electricity Capacity (Amendment) Regulations 2015. This Impact Assessment provides the analytical justification for the detailed design choices made on integration of interconnectors in the GB Capacity Market. It discusses on what basis and in which form interconnectors should participate in future Capacity Market auctions through largely qualitative analysis, along with quantitative analysis of the impact of their participation on 1) interconnector revenues and 2) the Capacity Market clearing price.

1.5 The quantitative analysis in Section 6 indicates that more interconnector capacity can lower the Capacity Market auction clearing price, while less interconnection puts upward pressure on the clearing price.[4] The qualitative analysis in Section 7 gives more detail on the different options for how interconnectors could be included in the Capacity Market.

1.6 The conclusion of this analysis (presented in Section 8) – and therefore the approach set out in regulations – is that the interconnector itself is a participant and eligible for rolling annual (i.e. one-year) agreements. It would be de-rated to the realistic long run expectation of the contribution at times of stress, receive the same clearing price and be subject to the same obligations as other participants in the Capacity Market.

[1] 2.5GW are held in reserve for the T-1 auction in 2017.
[2] https://www.gov.uk/government/news/the-first-ever-capacity-market-auction-official-results-have-been-released-today
[3] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/252743/Capacity_Market_Impact_Assessment_Oct_2013.pdf
[4] Part of the analysis presented is based on a standardised set of assumptions, including technology costs and electricity demand at the time this analysis was undertaken. Modelling assumptions are set out in more detail in Annex A and B.

2 Background

2.1 Previous Impact Assessments for the Capacity Market – primarily December 2011[5], November 2012[6], May 2013[7], October 2013[8], June 2014[9] and September 2014[10] – have analysed the policy options that would best deliver our security of electricity supply objective. The key contribution from these previous impact assessments are:

- A capacity market is the preferred instrument to mitigate security of electricity supply risks compared to alternatives, including a strategic reserve and doing nothing.

- The September 2014 IA accompanied the final policy decision on the target capacity, made by the Secretary of State in line with the Delivery Body's recommendation.[11] Accordingly, the Dynamic Dispatch Model (DDM) of the Department for Energy and Climate Change (DECC) has been updated so that 53.3 gigawatt (GW) of capacity is targeted for the first delivery year (2018/19).[12] For all other delivery years (2019/20 onwards) the modelling of target capacity remains unchanged.

Modelling changes since September 2014

2.2 The DDM has been updated with November 2014 market intelligence, including updated plant closure years and Supplemental Balancing Reserve contract information[13].

Contribution of Interconnection

2.3 In December 2013, DECC published 'More interconnection: improve energy security, lowering bills'[14] setting out UK policy to increase electricity interconnection which can support government objectives in energy security, affordability and decarbonisation, including through facilitating the single European electricity market.

2.4 The Government is committed to enabling the effective participation of interconnected capacity in the Capacity Market, whilst at the same time retaining value for money for GB consumers and working within the rules being implemented across the European Union (EU) to harmonise wholesale electricity markets.

[5] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42797/3883-capacity-mechanism-consultation-impact-assessment.pdf
[6] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66039/7103-energy-bill-capacity-market-impact-assessment.pdf
[7] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/197911/capacity_market_ia.pdf
[8] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/252743/Capacity_Market_Impact_Assessment_Oct_2013.pdf
[9] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/324430/Final_Capacity_Market_Impact_Assessment.pdf
[10] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/354677/CM_-_revised_IA_and_front_page__September_2014__pdf_-_Adobe_Acrobat.pdf
[11] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/324973/20140627_Edward_Davey_to_Nick_Winser_and_Mark_Ripley.pdf
[12] This is the main change since the June 2014 IA. For the June 2014 IA, the DDM calculated the target capacity that would meet a loss of load expectation of 3 hours per year in 2018/19. 53.3GW is the requirement for the CM in 2018/19 after accounting for capacity that we expect to be delivered from other policies.
[13] http://www2.nationalgrid.com/UK/Services/Balancing-services/System-security/Contingency-balancing-reserve/SBR-Tender-Documentation/
[14] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/266460/More_interconnection_-_improving_energy_security_and_lowering_bills.pdf

2.5 Eligibility for the first Capacity Market auction (held in December 2014) included GB-located capacity only. This is because a workable solution to incorporate non-GB capacity could not be put in place in the timescale available. This Impact Assessment presents the options for the inclusion of interconnectors in the Capacity Market from the second capacity auction, in December 2015 for delivery in 2019/2020.

2.6 By giving access to electricity generation capacity in other markets, interconnection can improve security of supply at times of system stress up to its de-rated capacity, providing market prices reflect scarcity and flows across interconnectors follow prices differentials. This may reduce the need for domestic backup plant. Following gate closure, interconnectors can further support electricity security at times of system stress through use of commercial contracts for Emergency Assistance available for the System Operator to call upon if the market had failed to meet demand.

2.7 However, accurately assessing the contribution of interconnectors to GB security of supply is a complex issue. The EU Target Model, the Third package and EU Network Codes require that interconnectors are treated as transmission capacity and, taken together with market coupling[15], they facilitate the flow of electricity according to price differentials only. However, not being able to guarantee the direction of flow is a challenge for determining the contribution to capacity, further complicated by differences in the desired level of security (such as the Reliability Standard in GB, set at 3 hours Loss of Load Expectation) between interconnected markets.[16]

2.8 Estimating the future flow of interconnectors at times of system stress is difficult due to:

- Uncertainty around future power price developments,
- Recent developments in EU legislation (market coupling) and Ofgem rules (cash out) which will have a significant impact on improving the efficiency of interconnector flows,
- Structural changes between interconnected markets (that may impact on security of supply) , for example due to changing generation mixes in European countries, and
- Coincidence of system stress events that may occur between GB and some European countries.

2.9 Due to these rapid changes in power markets, historical data may not be a completely robust indicator of future interconnector flows. In theory, electricity should flow from areas of low price to areas with high prices, meaning electricity should flow into GB when prices are higher than in interconnected markets. However, historical electricity prices may not reflect the value of capacity at times of system stress. Ofgem's reforms of cash-out[17] should mean that wholesale electricity prices better reflect scarcity conditions, while European market coupling is improving the efficiency of interconnector flows (i.e. to ensure they follow price differentials). Together we expect that this will improve the likelihood that interconnectors will flow into GB at times of system stress. It is also hard to make inferences from historical data as GB has not experienced periods of significant stress in recent years.

[15] Market coupling involves combining all bids and offers in a region to create a larger, integrated electricity market in the area concerned. For example, in February 2014 Grid operators and power exchanges from 14 EU Member States (Belgium, Denmark, Estonia, Finland, France, Germany, Austria, UK, Latvia, Lithuania, Luxembourg, the Netherlands, Poland and Sweden) plus Norway inaugurated a pilot project for joint electricity trading.
[16] France also has a 3 hours Loss of Load Expectation, Ireland 8 hours and Netherlands 4 hours.
[17] https://www.ofgem.gov.uk/ofgem-publications/87782/electricitybalancingsignificantcodereview-finalpolicydecision.pdf

2.10 For some countries, particularly those with a large amount of renewable electricity generation, there may be a risk that stress events are increasingly associated with temperature and weather affecting wind output. Where wind output and temperature is highly correlated across neighbouring European markets, the contribution of interconnection to security of electricity supply may be limited.

Effects of including interconnectors in the Capacity Market

2.11 Interconnectors derive their revenues from congestion rents – payments for the capacity to trade electricity, dependent on price differentials between the connected markets. In Britain, there are two routes for investment. Under the 'merchant-exempt' model, private developers identify market opportunities and take the full upside and downside risk on revenues. These projects must seek exemptions from certain aspects of EU legislation.[18]

2.12 Alternatively, developers whose projects meet eligibility criteria may apply to Ofgem for 'Cap and Floor'[19] regime, whereby revenues above the cap will be passed back to consumers, but should they fall below the floor a top-up payment up to the level of the floor will be underwritten by consumers. Ofgem will determine cap and floor levels on a project-by-project basis through applying financial parameters to the efficient costs of developing and operating the project. While the floor reduces the risk of revenue volatility affecting interconnectors, the return received by investors 'between' the floor and the cap is driven by market forces. In this context, the receipt of revenues from the Capacity Market may decrease the likelihood of projects requiring floor payments and increase the likelihood of projects reaching the cap.

2.13 The analysis undertaken in Section 6 sheds further light in the impact of Capacity Market on interconnector revenues. We expect that, if Capacity Market revenues have a limited impact on interconnector returns, interconnectors are likely to submit low bids into the Capacity Market auction, which will mean that they have a good chance of clearing.

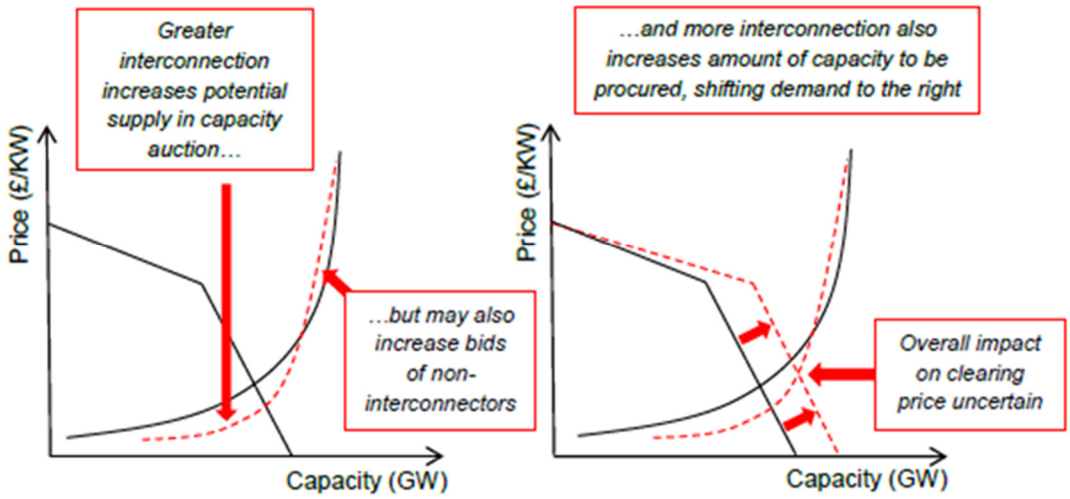
2.14 The participation of interconnected capacity in the Capacity Market is expected to increase the pool of competitors and could help to achieve a lower clearing price. However, although allowing interconnectors to participate increases the amount of capacity competing for agreements, the volume of capacity to be contracted under the Capacity Market also increases (see Figure 1) in accordance with the assumptions of interconnector contribution. Interconnector participation in the Capacity Market will therefore only decrease clearing prices, if it causes more interconnection to be built or if interconnectors put pressure on the marginal plant to bid more competitively. However, increased interconnection (and hence greater imports) may also mean that existing generators receive lower energy market revenues and consequently increase their bids in future Capacity Market auctions.

2.15 Regardless of the impact on clearing prices, with interconnector participation the capacity to be contracted under the Capacity Market is unambiguously higher. This increases the overall policy cost to the extent that buying more capacity is not offset by a decrease in the clearing price. We have not attempted to quantify this overall impact on policy costs through a comprehensive modelling of the wider Capacity Market intervention, which includes any associated impact on consumer bills.

[18] See Article 17 of Regulation (EC) no. 714/2009, available at: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0015:0035:EN:PDF

[19] https://www.ofgem.gov.uk//publications-and-updates/decision-roll-out-cap-and-floor-regime-near-term-electricity-interconnectors

Figure 1: Illustrative Impact of interconnector participation on the clearing price



Interconnection assumptions for modelling purposes

2.16 Britain currently has 3.75GW of available interconnection capacity: 2GW to France (IFA), 1GW to the Netherlands (BritNed), and 750MW[20] to the Irish grid (East-West and Moyle).

2.17 Since the last published Impact Assessment of the Capacity Market in September 2014, DECC has reviewed the policy developments and evidence in relation to interconnection, which fall into 3 categories:

- Sharpening and changing price signals: Ofgem's announcements on cash-out reform.
- Regulatory developments: Market coupling at the day-ahead stage as so far been successfully trailed with GB's interconnectors with France (IFA) and Netherlands (BritNed).
- Future interconnection with the continent: NEMO (a 1GW interconnector between GB and Belgium) has now received its final regulatory settlement and five further projects are being assessed by Ofgem for Cap & Floor regulation.[21] This means we can be more certain of an increase in future interconnection capacity.
- Due to these developments, DECC has revised its modelling assumptions compared to past Impact Assessments, which results in a higher future contribution from interconnectors to GB security of supply, at times of system stress.

[20] The installed interconnector capacity to Ireland is two links of 500 MW each but the Moyle interconnector has been operating at lower capacity in recent years.
[21] FAB and IFA2 (to France), Greenlink (to Ireland), NSN (to Norway) and Viking Link (to Denmark): https://www.ofgem.gov.uk/ofgem-publications/90803/cfeligibilitydecisionfinal.pdf

2.18 The analysis, presented in this Impact Assessment, continues to use the assumption of 3.75GW for existing interconnector capacity, which corresponds to 1.5GW de-rated capacity[22]. We have updated our assumptions about future interconnection capacity, based on the evidence sources and a report by Baringa[23]. This means that we estimate that a total of 5.4GW of de-rated capacity is available from interconnection by 2030.

2.19 Nevertheless, despite the developments and additional evidence outlined above, uncertainty over how future interconnector flows may respond to tight security of supply conditions in GB remains. We believe that our revised assumptions on interconnection, allowing for a larger contribution from the continent at times of system stress, are reasonable whilst recognising the related uncertainties.

[22] The Capacity Market Impact Assessment published in September 2014 provides more detail. Current capacity (3GW) to the continent is de-rated at 75% (2.25GW). To be prudent, the interconnector to Ireland is assumed to export at times of system stress with a de-rated capacity of 0.75GW.

[23] New electricity interconnection to GB – operation and revenues, February 2014, Baringa, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/322005/new_electricity_interconnection_to_gb_operation_and_revenues_baringa.pdf

3 Objectives

3.1 As set out in the previous Impact Assessment, the high level objectives of a capacity market are:

- Security of electricity supply: to incentivise sufficient investment in generation and non-generation capacity to ensure security of electricity supplies.
- Cost-effectiveness: to implement changes at minimum cost to consumers.
- Avoid unintended consequences: to minimise design risks and ensure compatibility with other energy market policies, including decarbonising the power sector.

3.2 Including interconnectors in the Capacity Market can help to achieve these objectives:

- A greater degree of interconnection can help to reduce the overall level of investment needed in GB capacity to the extent that interconnected capacity provides security of electricity supply. In addition, interconnectors can help diversify GB generation stack with that of neighbouring countries and can consequently reduce the incidence of supply stress events by virtue of this diversification.
- The participation of interconnected capacity in the Capacity Market is expected to increase the pool of competitors and ensure fair and equitable treatment for interconnection. In addition, this could help to achieve a lower clearing price, resulting in a lower cost to consumers. However, as outlined above, this impact depends on whether more interconnection is built and the response of other market participants to interconnector participation.
- Commitment to the EU internal energy market is a cornerstone of GB energy policy and further interconnection is a key part of that. Indeed, DECC's interconnection policy statement from December 2013[24] recommends further interconnection to markets as being beneficial for GB by supporting government objectives in energy security, affordability and decarbonisation, including through facilitating the single European electricity market.
- Participation of interconnectors featured prominently in the European Commission's State Aid decision for the Capacity Market[25], which includes a commitment from the Government to include interconnected capacity in some form, for auctions taking place for delivery year 2019/20 onwards.

[24] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/266460/More_interconnection_-_improving_energy_security_and_lowering_bills.pdf
[25] http://ec.europa.eu/competition/state_aid/cases/253240/253240_1579271_165_2.pdf

4 Rationale for intervention

4.1 Previous Impact Assessments have identified market failures present in the energy-only market that justify the introduction of a capacity market. An energy-only market may fail to send the correct market signals to ensure optimal security of electricity supply, including enabling investors to obtain the necessary finance for building new capacity. This is commonly referred to as the problem of 'missing money', where the incentives to invest are reduced, due to the three reasons below:

- Current wholesale energy prices do not rise high enough to reflect the true value of additional capacity at times of scarcity. This is due to the charges to generators who are out of balance in the Balancing Mechanism (cash-out) not reflecting the marginal costs of balancing actions taken by the System Operator (such as cost of contracting plant in the balancing market and ancillary services or customer disconnections).

- Stress events are unlikely to occur frequently. With an increasingly decarbonised power sector, investors face uncertainty about running hours and so will be increasingly reliant on recovering fixed costs through infrequent and uncertain scarcity rents.

- At times when the wholesale energy market prices peak to high levels, investors are concerned that the Government or regulator will act on a perceived abuse of market power, for example through the introduction of a price cap.

4.2 The Government has decided to introduce a market-wide capacity market 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, including at times of system stress.

4.3 As outlined above, the Capacity Market has been put in place to address investor concerns about this missing money. Increasing uncertainty about running hours and reliance on very high prices during periods of scarcity to recover their fixed costs, which investors may find difficult to predict may therefore mean that an energy-only market might not provide sufficient incentives to invest in enough generating capacity to meet demand.

4.4 The rationale for including interconnectors in future Capacity Market auctions is, in particular, based on ensuring that incentives for additional investment are not potentially skewed in favour of GB generation (potentially at the expense of more efficient interconnection to European markets). This could happen if investors choose to develop new domestic power plants instead of more interconnection capacity, because of the additional investment incentive provided to domestic capacity through Capacity Market payments, in addition to the GB wholesale electricity price.

4.5 Interconnectors to GB could possibly be deprived of revenue, as the Capacity Market is expected to have a dampening effect on the wholesale electricity price in GB (as shown in previous DDM modelling). This may damage their business case and undermine future investment in interconnection projects.

4.6 The investment in interconnectors depends on a number of economic and regulatory factors, including the Cap and Floor regime which aims to reduce some of the risks around interconnector investment. The Capacity Market is intended to complement measures to strengthen energy market incentives for investment. Therefore, the primary rationale behind including interconnectors in the Capacity Market is not to directly boost interconnector investment, but to ensure that the Capacity Market works efficiently to provide security of supply for GB at lowest cost to consumers as well as to avoid unintended impacts on interconnector projects as a result of government policy design.

5 Options Appraisal

5.1 As set out earlier, previous Impact Assessments set out the evidence for the choice of a capacity market as the lead policy option to mitigate risks to GB electricity security of electricity supply. Therefore, these issues are not revisited here.

5.2 This Impact Assessment presents evidence supporting the design choices with respect to treatment of interconnectors within the Capacity Market. It discusses on which bases interconnectors should participate in future Capacity Market auctions, primarily based on qualitative analysis. It also presents quantitative analysis, which focuses on what impact interconnector participation in the Capacity Market has on 1) interconnector revenues and 2) the Capacity Market clearing price.

Option assessment

5.3 Relevant options are appraised through both qualitative and quantitative analysis. The quantitative analysis in Section 6 indicates that more interconnector capacity can lower the Capacity Market auction clearing price, while less interconnection puts upward pressure on the clearing price.

5.4 To complement these quantitative estimates, the qualitative assessment provides a more comprehensive assessment of the following design choices, as set out in the recent policy consultation:

- Bidding party: Interconnector- versus generator-led
- Nature of the capacity obligation: ‘Delivered energy’ versus ‘declared availability’
- Penalty regime
- De-rating
- Agreement length

6 Quantitative Options Assessment

6.1 Two value for money assessments have been undertaken to evaluate the impact of interconnector participation in the Capacity Market:

1. Potential impact on interconnector revenues via commercial analysis, using financial modelling;

2. Potential impact of more interconnection on the Capacity Market clearing price, using the DDM.

Impact on interconnector returns

6.2 As outlined above, the Capacity Market is expected to dampen the GB wholesale price and therefore have a potential effect on the returns of interconnectors, potentially affecting investment decisions.

6.3 To evaluate the business case for investment in new interconnectors, we modelled the potential impact on investment for projects being brought forward as merchant projects[26] as well as under Ofgem's Cap and Floor regime. The analysis has considered a range of potential interconnector projects. Further detail on the modelling assumptions is provided in Annex B.

Results

6.4 The commercial analysis indicates that the inclusion of interconnectors in the Capacity Market has a limited, but positive, impact on interconnector returns, in particular for 'long-cable' projects (such as a potential interconnector to Scandinavia). The exact impact will depend mostly on the specific commercial merits of each project and on the assumed level of the Capacity Market clearing price.

6.5 The analysis also has considered how investability could change when longer capacity agreements are provided to interconnectors, both for merchant interconnectors and for interconnectors coming forward under Ofgem's Cap & Floor regime. This analysis is discussed in Section 7.

Impact on the clearing price

6.6 As set out earlier in Section 2, interconnection participation in the Capacity Market auction is likely to have an effect on the clearing price. However, a priori, it is difficult to assess the likely magnitude and direction of this effect.

6.7 In order to attempt to quantify the effect of interconnector participation on the Capacity Market clearing price, we use the DDM to model the impact on Capacity Market auction clearing prices, for a range of scenarios based on different volumes of interconnector build in the future.

[26] For merchant projects, private developers identify market opportunities, construct and operate the assets, and take the full upside and downside risk on revenues. Merchant projects seek exemptions from various aspects of EU legislation, in particular around the use of revenues.

6.8 Currently, it is not possible to endogenously model interconnector investment decisions within the DDM and any interaction between Capacity Market revenues and interconnector build. Therefore, the modelling assumes that the interconnector build is exogenous across the range of scenarios considered below.[27] This is also a justifiable approach as the results of the commercial analysis indicate that Capacity Market participation is unlikely to significantly change interconnector financeability.

6.9 The following scenarios for interconnector capacity have been considered against the counterfactual (central scenario), based on the latest evidence presented in Section 2, where the current capacity is 3.75GW (de-rated to 1.5GW). In addition, a total of 3.15GW of de-rated capacity comes forward in stages by 2030.

1. High scenario: Compared to the central case, 1.47GW of de-rated capacity comes on earlier than in the central scenario, which implies an additional 0.84GW of de-rated capacity compared to the central scenario by 2030.

2. Low scenario: Compared to the central case, existing interconnectors are assumed to be at float throughout at times of system stress, in line with National Grid's Future Energy Scenario. Furthermore, 0.7GW of de-rated capacity is added in 2019/20.

6.10 If Capacity Market revenues have only a limited impact on interconnector returns, it is likely that interconnector bids into the Capacity Market auctions will be low enough for them to have a good chance of clearing the auction.

6.11 The participation of interconnected capacity in the Capacity Market is expected to increase the pool of competitors and could help to achieve a lower clearing price.

- Although allowing interconnectors to participate increases the amount of capacity competing for agreements, the volume of capacity to be contracted under the Capacity Market also increases in accordance with the assumption of interconnector contribution. Interconnector participating in the Capacity Market will therefore only decrease clearing prices if it causes more interconnection to be built. In short, when interconnectors participate, supply as well as demand increases by the same amount, unless new interconnection is built.

- Interconnector participation could put pressure on the marginal plant to bid more competitively. However, more interconnected capacity (and hence electricity imports) may mean that existing generators receive lower energy market revenues and increase their bids in future Capacity Market auctions accordingly. The modelling does account for this potential impact on energy-only revenues, hence bidding behaviours of other plant associated with different levels of interconnection.

6.12 Regardless of the impact on clearing prices, with interconnector participation the capacity to be contracted under the Capacity Market is unambiguously higher. This increases the overall policy cost to the extent that buying more capacity is not offset by a decrease in the clearing price. We have not attempted to quantify this overall impact on policy costs through a comprehensive modelling of the wider Capacity Market intervention, which includes any associated impact on consumer bills.

[27] In the current modelling, interconnectors do not participate in Capacity Market auctions. In place of bidding into the auction, interconnectors are taken into account by netting off estimates of de-rated interconnector capacity from the required capacity, to ensure a maximum 3 hour Loss of Load Expectation.

Results

6.13 Modelling results which attempt to quantify the impact of different interconnection scenarios on the Capacity Market clearing price indicate that:

- A greater amount of interconnection (comparing the high and central scenario) generally exerts downwards pressure on clearing prices, with an average reduction of around £3/kW between 2019 and 2030. The dampening effect is more pronounced for the first 5 years due to interconnection capacity being brought forward to that time period in the high scenario. After that, the impact becomes more variable across years, with reductions in some years and increases in others. This may be influenced by the front-loading of new capacity in the high compared to central scenario. It is not currently possible to model interconnector investment endogenously within the DDM.

- Less interconnection (comparing the low and central scenarios) has a more unambiguous upward impact on Capacity Market clearing prices, resulting in an average increase of around £8/kW between 2019 and 2030. Nevertheless, as outlined for the high scenario, there is still a greater degree of volatility in results beyond 2023.

7 Qualitative Options Assessment

7.1 To complement the quantitative analysis in assessing the impact of interconnection on the Capacity Market, we have conducted a qualitative assessment on the following options:

A. Bidding party: Interconnector- versus generator-led model

B. Nature of the capacity obligation: Delivered energy versus declared availability

C. Penalty regime

D. De-rating

E. Agreement length

7.2 We have assessed each of these choices against a set of criteria, including:

- Efficiency: does the option avoid reduced incentives for investment in interconnection relative to generation, and avoid impacts on short-run dispatch decisions?
- 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 developments on the EU level

A. Bidding party: Interconnector- versus generator-led model

7.3 When including interconnected capacity in the Capacity Market, the question of who holds the capacity obligation is central. There are two possibilities, 1) the interconnector owner or 2) the non-GB generator (or resource, e.g. DSR) participate.

Interconnector-led options

7.4 Both interconnector- and generator-led options allow payments to flow to the interconnector owner to support efficient investment in interconnectors. The signal may be more direct for the interconnector-led options.

7.5 In the interconnector-led option, there may be fewer gaming risks. To the extent that there is a specific concern about generator market power in an interconnected market, interconnector-led options remove their direct participation.

7.6 Interconnector-led options are also simpler to administer. Fewer parties are bidding into the auction and fewer participants require verification. An interconnector-led approach also requires a smaller degree of co-operation with neighbouring Transmission and System Operators (TSOs) in other countries on measurement and verification. An interconnector-led option should also, in principle, be relatively more easily incorporated into the existing design of the capacity auction.

7.7 For the interconnector-led approach, it was considered whether the interconnector owner actively participates by bidding in the Capacity Market auction, or simply receives a capacity payment, i.e. is passive. A report conducted by Frontier Economics for DECC gives more information on these options.[28] However, the passive role is deemed to be suboptimal and not aligned with the rationale for the intervention, because it would not accurately remove potential impacts on investment incentives between GB and foreign generation caused by CM as well as allowing interconnectors to compete directly.

Generator-led options

7.8 Alternatively, non-GB generators could hold the Capacity Market obligation. In considering the participation of non-GB generators in the Capacity Market, an important question concerns whether there should be limits placed on the location of generators eligible to bid. There are two potential approaches to assessing the eligibility of generators based on their location:

- Unrestricted option – the participation in the GB Capacity Market is allowed from any generator within the Internal Electricity Market (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 Capacity Market. The obligation and penalty regime would not vary by location.

- Restricted option – eligibility is determined on the basis of contribution to GB system adequacy. In this version of the option, capacity that bids into the Capacity Market is de-rated according to the likelihood that power will flow and make a positive contribution to GB during a system stress event. In effect this would imply that remote capacity, which is separated from GB by numerous (potentially congested) interconnectors and is therefore more limited in its ability to contribute to GB system adequacy will be de-rated more heavily. This de-rating could take place during prequalification on the basis of its specific location, requiring a complex calculation to be applied to bids.

7.9 A generator-led option may appear to be more intuitive in that it is more consistent with the current Capacity Market design for domestic capacity providers and is more aligned with the current debate at EU level. However, it significantly increases complexity, as it potentially means many non-GB parties bidding into the auction. It would also require a change to a number of aspects of the Capacity Market auction parameters, pre-qualification, the auction design, secondary trading, and further work on the nature of the obligation and product that a non-GB plant can offer. It would also require further consideration of the penalty regime and how to split the obligation as well as the risk of non-delivery between the non-GB generator and the interconnector.

7.10 There is a view that an enduring cross-Europe solution for participation in capacity markets is more likely to revolve around generator-based options in the longer term. An option which is more consistent with a longer-term Europe-wide solution would bring benefits through reduced future costs of transition. There could therefore be advantages of moving to a generator led model now to limit the costs of future change.

[28] Participation of interconnected capacity in the GB Capacity Market, September 2014, Frontier Economics, http://www.frontier-economics.com/documents/2014/05/frontier-report-interconnector-participation-in-capacity-remuneration-mechanisms.pdf

7.11 The proposed approach in the recent consultation[29] was an interconnector-led solution. The majority of respondents agreed that the proposed interconnector-led model is an acceptable interim solution; they argued it will send the right investment signals and will contribute to security of supply. Some respondents preferred a generator-led approach but also recognised that this solution is unlikely to be possible in the short term, given the extent of international co-ordination that would be required.

Conclusion

7.12 As explained above, a generator-led solution is likely to require a significant amount of international cooperation to bring to fruition. Also, should the EU end up pursuing a different approach for cross-border capacity market participation in the future, it would be very complicated to remove or change. In light of the above discussion, an interconnector-led approach as a transitional measure is thought to be more appropriate in the interim.

7.13 This will mean that interconnectors will be eligible to participate in the GB Capacity Market in auctions for the delivery year 2019/2020 onwards. The T-4 and T-1 auctions for this delivery year will take place in 2015 and 2018 respectively. Interconnector owners will be the bidding parties and will become the holder of a capacity agreement up to the level of their de-rated capacity. They will receive the clearing price in the auction and will hold the capacity obligation in line with requirements for other resources.

B. Nature of the capacity obligation: Delivered energy versus declared availability

7.14 The nature of the capacity obligation is important when considering the delivery aspect of the policy design – whether the obligation is based on delivered energy or declared availability.

- In an availability model, an 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.

- In a delivered energy model, the obligation is fulfilled if the market delivers the agreed de-rated level of electricity through the interconnector at times of stress. This highlights a key feature of this model, which is the exposure of the capacity provider to a risk which may be out of its control. For example, an interconnector may be physically available to flow but, due to a coincident stress event or market imperfection elsewhere, it may not flow into GB at a time of system stress at the level of its de-rated capacity. This could potentially affect the appetite of interconnectors to participate in the Capacity Market.

Declared availability model

7.15 Availability is a different and arguably less secure product (capacity that has to be technically available) than that currently secured via the Capacity Market auction (capacity that has to be delivered). Availability is more complicated to monitor and creates a significant vulnerability to gaming, a problem that has been observed, for example, in the United States.[30] These problems would likely require comprehensive testing and monitoring to mitigate these risks.

[29] Consultation on the Capacity Market Supplementary Design and Transitional Arrangements, September 2014, DECC, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/358461/CM_October_Condoc_FINAL.pdf
[30] See Annex 'International Review' in the report by Frontier Economics,

7.16 Models where the obligation relates to availability may also lead to investment inefficiencies. In an availability model, the interconnected capacity is not exposed to the risk that power does not flow into GB during the stress event. The delivery risk is transferred to GB consumers for interconnected capacity but not for domestic generation. This may represent an implicit subsidy to interconnectors participating in the CM, which could potentially impact on investment decisions.

7.17 Therefore, an availability-based model would mean paying the same price in the auction for a different, potentially less secure product or redesigning the auction completely to take account of different products.

Delivered energy model

7.18 A delivered energy model is the basis of the current GB Capacity Market obligation for capacity providers. This means that there is a requirement to provide electricity when a Capacity Market warning is called, and penalties are imposed if a capacity provider is not delivering during a stress event. This design choice was made because it was considered an appropriate and proportionate way of ensuring that the plant bidding in to the Capacity Market is incentivised to deliver security of supply when it is most needed. This model is also quite resilient to gaming. In addition, under the current design of the Capacity Market, we have a single product auction where only one product – delivered energy – is procured.

7.19 Models where the obligation relates to cross-border delivery-based incentives may have potential to lead to dispatch inefficiencies in the non-GB market – for example, if a generator is obliged to generate out of merit in its own market, due to a requirement to provide capacity during a stress event in GB. However, this is a small risk and dependent on the policy design, so can be mitigated.

7.20 Notwithstanding this small risk, a delivery-based model was determined as the best way to enhance security of supply. Considering the uncertainty around interconnector flows, this approach reduces the exposure to consumers –it allows the Government to measure performance and levy penalties for non-delivery against the capacity agreement. This ensures that consumers do not pay for something that ends up not being delivered. This is consistent with the current arrangements for domestic capacity providers. It also accounts for the uncertainty of flows until a more developed evidence base on the impact of market coupling on interconnector flows is available.

7.21 While the interconnector is asked to accept a market risk, it is also worth noting that the penalty liability will not exceed Capacity Market revenues in any given year. This approach does not create any different treatment for interconnectors in comparison to other resources.

7.22 It is worth noting that neither delivered energy nor declared availability for interconnected capacity would guarantee that electricity flows to GB over interconnectors at times of system stress. This is because the direction of flow is determined by price differentials between the interconnected markets. That said, following the reform of imbalance pricing by Ofgem (the Electricity Balancing Significant Code Review (EBSCR) and the full implementation of market coupling, we do expect a positive security of supply contribution over interconnectors at times of system stress through more price-reflective trades. This is because GB prices should be higher, given the differences in underlying generation mix (hence short-run costs of the marginal generator) and relative differences in non-dispatch costs (e.g. Carbon Price Floor).

7.23 In the consultation, the majority of stakeholders agreed that, if interconnectors participate directly, they should bid under the same rules as domestic generation and for the same product, i.e. delivered energy. A few respondents argued that the existing Capacity Market model of delivered energy is not appropriate for interconnectors as they do not have control over the direction of flow of energy.

Conclusion

7.24 Given the arguments above, the nature of the obligation of interconnected capacity will be based on the delivered energy model, as per the existing rules for domestic generation. The level of the obligation will be the de-rated capacity of the interconnector – the realistic long run expectation of imports at times of system stress.

C. Penalty regime

7.25 The choice of the penalty regime is closely related to the choice between the delivered energy and the declared availability model. Depending on the type of obligation that is placed on the interconnector, there are different options for how penalties are levied and the way risk is managed.[31] The focus here lies on the question whether interconnectors should be subject to the same penalty regime as all other Capacity Market participants.

7.26 The Capacity Market design aims to treat capacity equally and to include interconnector owners on the same basis as domestic generation. Therefore, interconnectors should be subject to the same penalty regime. The existing penalty regime effectively caps penalties at the level of benefits received. It therefore does not create any particular unfairness for interconnectors.

7.27 In the latest consultation, the majority of respondents supported the view that interconnectors should be treated the same as all other Capacity Market resources, given that receive the same clearing price.

7.28 As with other resources, the energy market provides the main incentives for delivery. The penalty regime is not designed to supplant this; rather it acts as a method to "true-up" the performance of resources in relation to their de-rated capacity. This will also be true for interconnectors in that there will be a requirement to reach the level of the capacity obligation when a Capacity Market warning is issued. This is in line with Government's intention to have a 'single product' auction where only one product - delivered energy - is secured.

Conclusion

7.29 The Government's policy is to treat interconnection on the same basis as all other Capacity Market resources. The existing penalty regime caps penalties at the level of benefit received. Therefore it does not create any particular different treatment for interconnectors in comparison to other resources. As the penalty regime is capped, we believe it mitigates the risk of the Capacity Market influencing flows. This latter issue has been an important consideration for the Government in the development of this policy.

[31] A more detailed discussion can be found in: Participation of interconnected capacity in the GB Capacity Market, September 2014, Frontier Economics, http://www.frontier-economics.com/documents/2014/05/frontier-report-interconnector-participation-in-capacity-remuneration-mechanisms.pdf

D. De-rating

7.30 De-rating provides, statistically, the long-run expectation of a resource's contribution to electricity supply at times of system stress, and therefore the amount of capacity eligible for capacity payments. The following paragraphs explain why finding a de-rating methodology is less straightforward for interconnectors than for domestic capacity and outlines the success criteria that should apply to any chosen approach.

7.31 The de-rating factor of any resource is estimated statistically as the long run expectation of their contribution to security of supply, i.e. energy delivered that a given resource class can offer at times of system stress. A de-rating factor for domestic generation is based on how often we expect a technology to be taking an outage for technical reasons whether this is routine planned maintained or unplanned. This is referred to as the 'technical factor' in this Impact Assessment. For interconnectors the technical factor is also relevant (i.e. we need to make an assumption of how often it will need to take outages) but we would expect interconnectors to be working most of the time.

7.32 The more important consideration is the proportion of time we expect the interconnector to be importing to GB as opposed to exporting during such times of system stress. This is referred to as the 'country flow' factor in this Impact Assessment. This is dependent on the relative prices in countries at either end of the interconnector (i.e. electricity should flow from areas of low price to areas of high price) and if electricity markets are efficient enough to facilitate trade according to these price signals.

7.33 The determination of the de-rating factor is ordinarily a backward facing, statistical exercise. For the mainstream Capacity Market, de-rating of domestic generation takes seven years of historical data from the balancing market and uses this data as the best predictor of future performance. This methodology has the advantage of being simple and transparent, but may be less appropriate for interconnectors because of known and anticipated rapid changes in the future operating environment:

- Europe's electricity generating infrastructure is generally shifting towards greater penetration of renewables, a move away from nuclear energy in some countries and a pressure on gas plant profit margins. These factors drive different generation mixes across countries, which will change the dynamics of price signals across Europe.

- Interconnectors have begun operating within the new EU-wide legislative framework, known as market coupling (introduced in in February 2014).[32] This new regime means that the flows over the interconnectors are determined by a computer algorithm which schedules interconnector flows from lower-priced to higher-priced markets. Further developments over the coming years will begin to introduce market coupling to intra-day markets and with the Irish Single Energy Market.

- Ofgem's cash-out reform will allow prices in GB to more accurately reflect scarcity. This will make it more likely that interconnectors flow to GB at times of system stress.

[32] http://www.acer.europa.eu/Media/News/Pages/ACER-welcomes-the-day-ahead-market-coupling-in-15-countries-and-publishes-its-latest-Status-Review-Report-on-Regional-initi.aspx

- Furthermore, there is not yet a comprehensive and robust body of statistical data across interconnectors, especially their behaviour in stress events due to the limited number of interconnectors to GB and the relatively comfortable capacity margins that GB has historically experienced.

7.34 The following success criteria should apply to the preferred de-rating option:

1. Reflect likely future technical reliability
2. Reflect likely future direction of system flows at times of system stress
3. Be calculated for individual interconnectors, rather than on a generic sector basis
4. Mitigate any potential conflict of interest and ensure that no undue influence has had an effect on the final determination of the de-rating factor

7.35 The final de-rating methodology will be outlined in the publication of the Capacity Market Rules in March 2015. DECC plans to engage with industry before this date to ensure that stakeholders are kept abreast of developments and have an opportunity to comment. We are also currently undertaking further work to understand the risk exposure of different de-rating options.

7.36 De-rating factors will be published annually in June, together with factors for domestic generation, via the auction guidelines.

E. Agreement length

7.37 A further design consideration relates to the agreement length that interconnectors should receive in the Capacity Market.

7.38 All resources in the Capacity Market auction receive one-year agreements by default and a large burden of proof is required for any exception to this rule. The longer agreements available for new-build domestic generation were only introduced following an exhaustive policy development process and a wealth of evidence provided by the sector, followed by the Government's own analysis that this approach was suitable in this case. In the case of interconnectors, the Government has analysed responses to the latest consultation and, insofar as possible, undertaken some analysis to determine whether a similar bar was reached in terms of evidence to support an exception for longer agreements.

7.39 In contrast to the previous consultation on domestic new build, the latest consultation did not provide any convincing evidence in respect of interconnectors, or many tools on which to base analysis. The Government conducted analysis, to the extent possible, on the basis of the evidence available. This can be revisited if and when further, robust evidence emerges in future.

7.40 To the extent possible, we undertook commercial analysis of the business case for investment in new interconnectors (also see Section 6).

7.41 This commercial analysis investigated how interconnector investability and bankability may change, if longer agreements were provided to interconnectors in the Capacity Market. This was conducted both for merchant interconnectors and for interconnectors coming forward under Ofgem's Cap & Floor regime.

7.42 The outcome suggests that longer agreements for merchant interconnectors or for interconnectors coming forward under Ofgem's Cap & Floor regime would have a limited impact on Interconnector base case returns, depending mostly on the specific intrinsic commercial merits of each project and on the CM clearing prices.

7.43 The outcome also suggests that longer agreements for merchant interconnectors or for interconnectors coming forward under Ofgem's Cap & Floor regime do not have a significant impact on the level of project financing available to new interconnector projects.

- For merchant projects, the analysis shows that even with a 15-year agreement the capability to raise high levels of project finance debt would be very limited and would still require additional sources of assured revenues over the long term (e.g. securing long-term supply agreements).

- For projects coming forward under current Cap and Floor regime, capacity payments would be rolled into the overall calculation of revenues which are then subject to Cap and Floor mechanics. This means that Capacity Market payments would need to be guaranteed to be consistently higher than the floor to have any additional impact on the project financing capability.

7.44 There are two additional concerns with respect to longer agreements:

- First, longer agreements could exacerbate the challenge of accurate de-rating. Agreements beyond one year do not allow the interconnector de-rating to be adjusted according to the performance of the interconnector over time. The market risk associated with the interconnectors not flowing perfectly may improve over time, or the risk of coincident stress events may grow as penetration of renewables increases. If certainty over the level of interconnector capacity was thought to be more variable than that for domestic generators, it may be desirable to adjust the de-rating factor over time. One-year agreements would 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 agreements may create barriers and increase the cost of any transition. For example, switching to a generator-led option would prove more complex if a number of interconnectors already have long-term capacity agreements.

Conclusion

7.45 The agreement length for successful interconnectors in the Capacity Market auction will be one year. However, the question of agreement length - alongside many other issues of auction design - is subject to the regular review process and may be reconsidered if sufficient evidence is provided.

8 Conclusion

8.1 The Government has introduced a Capacity Market to address the missing money problem that may occur in the energy-only market and to incentivise sufficient reliable capacity (both supply and demand side) to ensure a secure electricity supply, even at times of peak demand.

8.2 Through the first auction in December 2014, the Government procured 49.26GW[33] of capacity at a clearing price of £19.40/kW (in 2012 prices).

8.3 The Government is committed to enabling the effective participation of interconnected capacity in the Capacity Market, whilst at the same time retaining value for money for GB consumers and working within the rules being implemented across the European Union (EU) to harmonise wholesale electricity markets.

8.4 Interconnection to other electricity markets can contribute to secure electricity supply in GB by allowing other markets to supply electricity at times of stress and potentially reduce the need to build domestic backup plant. Interconnectors also enable greater competition in the auction and ensure that the mechanism does not affect interconnector investment signals.

8.5 The rationale behind including interconnectors in the Capacity Market is to ensure that the Capacity Market works efficiently and at lowest cost, as well as to avoid potential consequences for interconnector projects as a result of government policy design.

8.6 This impact assessment has evaluated the inclusion of interconnectors in a quantitative and qualitative analysis. The quantitative analysis in Section 6 indicates that more interconnector capacity can lower the Capacity Market auction clearing price, while less interconnection puts upward pressure on the clearing price. However, we have not attempted to quantify the overall impact on policy costs through a comprehensive modelling of the wider Capacity Market intervention, which includes any associated impact on consumer bills.

8.7 The qualitative analysis in Section 7 gives more detail on how interconnectors will be included in the Capacity Market, presenting the approach whereby the interconnector itself is the Capacity Market participant and eligible for rolling annual agreements. The interconnector will be de-rated to the realistic long run expectation of the contribution at times of stress, receive the same clearing price and subject to the same obligations as other Capacity Market participants.

[33] 2.5GW are held in reserve for the T-1 auction in 2017.

9 Other Impacts

Impact on small firms

9.1 In terms of additional regulatory or administrative burdens, the Capacity Market will primarily impact on electricity generators in the sector, which are mostly classed as large businesses, which also includes interconnectors. In case a generator-led approach is chosen in the future, some capacity providers in the non-GB market may be small or medium-sized. These could be negatively impacted by additional administrative costs, should they decide to participate in the Capacity Market.

GB Competitiveness

9.2 The Capacity Market is not expected to have an impact on GB competitiveness[34] as the Capacity Market costs are likely to be offset by wholesale price savings. GB competitiveness should benefit from increased energy security boasting investor confidence. Furthermore, the Capacity Market should make the GB electricity sector more attractive for investors, including new commercially attractive, yet voluntary, Demand Side Response opportunities for businesses.

Implications for One-In, Two-Out

9.3 Based on the latest HMT advice, the Capacity Market options are to be treated as tax and spend measures, so would be out of scope for One-In, Two-Out (OITO).

Equality impact

9.4 It is not envisaged that the Capacity Market will impact on measures of equality as set out in the Statutory Equality Duties Guidance. Specifically, options would not have different impacts on people of different racial groups, disabled people, men and women, including transsexual men and women. There are also no foreseen adverse impacts of the options on human rights and on the justice system. We will keep a watching brief on this but we are confident that any issues have been addressed at the design stage without adverse impact on either human rights, or on the effectiveness of the mechanism.

Impact on Business

9.5 The Capacity Market has the potential to impact businesses, mainly through the benefit to businesses of reduced energy unserved and though the potential cost from higher energy bills (which is expected to be limited, as outlined above). More interconnection may transfer energy market revenues from GB generation to interconnector owners and foreign generators.

[34] Northern Ireland is part of the Single Electricity Market (SEM) electricity.

10 Post-Implementation Review

10.1 DECC has committed to regular reviews of the Capacity Market. There will be a five-yearly review of the mechanism, which will:

- Set out the objectives of the provisions of each Chapter subject to review,
- Assess the extent to which those objectives have been achieved, and
- Assess whether those objectives remain appropriate and, if so, the extent to which those objectives could be achieved in a less burdensome way.

10.2 This review will involve a public consultation to invite views. The outcome of the review will be published.

10.3 DECC has commissioned an independent evaluation of the Capacity Market (and Contracts for Difference) to provide independent assurance and utilise networks and evidence outside the Department. The outcome of this review will be published later in 2015.

10.4 Ofgem will also complete a yearly review of the operational effectiveness of the Capacity Market. This will be delivered within six months of the Capacity Market auction.

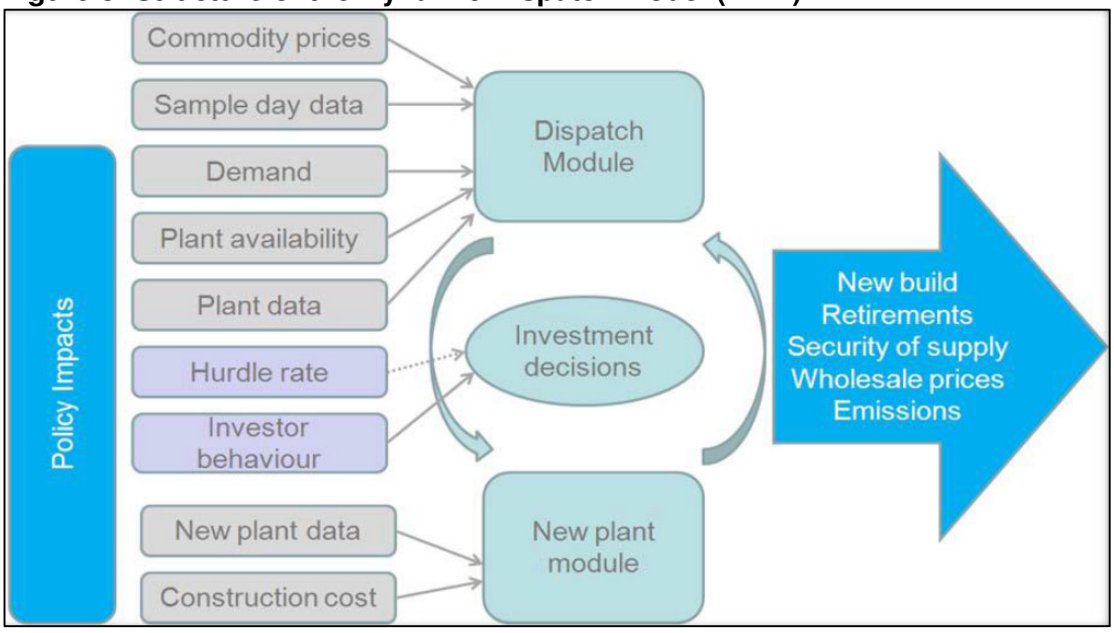
Annex A: Energy System Modelling

1. The Dynamic Dispatch Model (DDM) is a comprehensive fully integrated power market model covering the GB power market over the medium to long term. The model enables analysis of electricity dispatch from GB power generators and investment decisions in generating capacity from 2010 through to 2050. It considers electricity demand and supply on a half hourly basis for sample days. Investment decisions are based on projected revenue and cash flows allowing for policy impacts and changes in the generation mix. The full lifecycle of power generation plant is modelled, from construction through to decommissioning. The DDM enables analysis comparing the impact of different policy decisions on generation, capacity, costs, prices, security of electricity supply and carbon emissions, and also outputs comprehensive and consistent Cost-Benefit Analysis results.

Overview

2. The DDM is an electricity supply model, which allows the impact of policies on the investment and dispatch decisions to be analysed. The figure below illustrates the structure of the model.

Figure 8: Structure of the Dynamic Dispatch Model (DDM)



3. The purpose of the model is to allow DECC to compare the impact of different policy decisions on capacity, costs, prices, security of electricity supply and carbon emissions in the GB power generation market.

Dispatch Decisions

4. Economic, energy and climate policy, generation and demand assumptions are external inputs to the model. The model runs on sample days, including demand load curves for both business and non-business days, including seasonal impacts and are variable by assumptions on domestic and non-domestic sectors and smart meter usage. Also, there are 3 levels of wind load factor data applied to the sample days to reflect the intermittency of on- and offshore wind. The generation data includes outage rates, efficiencies and emissions, and also planned outages and probabilities of unplanned outages.

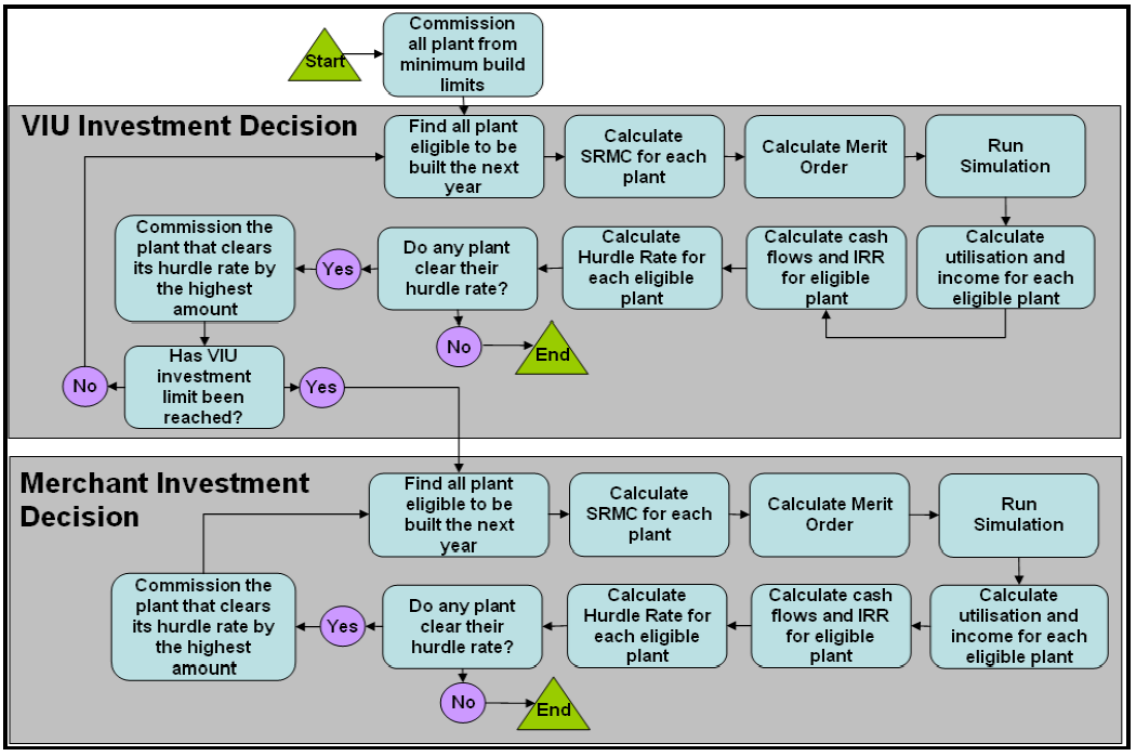
5. The Short Run Marginal Cost (SRMC) for each plant is calculated which enables the calculation of the generation merit order. Demand for each day is then calculated taking wind profiles into account and interconnector flows, pumped storage, auto-generation and wind generation. Once

the required reserve is calculated the system SRMC is calculated by matching the demand against the merit order and taking the SRMC of the marginal plant to meet demand. The wholesale price is equal to the system marginal price plus the mark up. The mark up is derived from historic data and reflects the increase of system marginal price above marginal costs at times of reduced capacity margins. Plant income and utilisation are calculated and carbon emissions, unserved energy, and policy costs are reported.

Investment Decisions

6. The model requires input assumptions of the costs and characteristics of all generation types, and has the capability to consider any number of technologies. In investment decision making the model considers an example plant of each technology and estimates revenue and costs in order to calculate an IRR. This is then compared to a user specified technology specific hurdle rate and the plant that clears the hurdle rate by the most is commissioned. This is then repeated allowing for the impact of plants built in previous iterations until no plant achieves the required return or another limit is reached. The model is also able to consider investment decisions of both Vertically Integrated Utilities (VIUs) and merchant investors, see the figure below. Limitations can be entered into the model such as minimum and maximum build rates per technology, per year, and cumulative limits.

Figure 9: Investment decisions in the DDM



Policy Tools

7. The model is able to consider many different policy instruments, including potential new policies as well as existing ones. Policies are implemented by making adjustments to plant cash flows which either encourage or discourage technology types from being built in future and impact on their dispatch decisions. The policy modelling has been designed flexibly and policies can be applied to all technologies or specific ones, only new plants or include existing plants and be

varied over time and duration. Policies can be financed through Government spending/taxation or charged to consumers.

Outputs

8. The model can be run in both deterministic and stochastic modes – this enables analysis to be carried out with different levels of randomness, allowing for more realistic treatment of uncertainty to be incorporated into the model outputs and better understanding of investment behaviour. The model outputs many metrics on the electricity market and individual plant that enables the policy impacts to be interpreted. Using these outputs a Cost Benefit Analysis is carried out on the model run including a distributional analysis.

9. The DDM therefore enables analysis to be carried out on policy impacts in different future scenarios, allowing DECC to consider and compare the estimated impacts of different potential policies on the electricity market.

Peer Review

10. The model was peer reviewed by external independent academics to ensure the model is fit for the purpose of policy development. Professors David Newbery and Daniel Ralph of the University of Cambridge undertook a peer review to ensure the model met DECC's specification and delivered robust results. The DDM was deemed an impressive model with attractive features and good transparency. For the Peer Review report see 'Assessment of LCP's Dynamic Dispatch Model for DECC' (http://www.decc.gov.uk/assets/decc/11/about-us/economics-social-research/5427-ddm-peer-review.pdf).

Levy Control Framework

11. On 23 November 2011, the Government agreed a Levy Control Framework (LCF) to 2020, which is set at a total of £7.6bn (in real, 2012 prices).[35] This will help diversify our energy mix by increasing the amount of electricity coming from renewables, as well as supporting new nuclear power and carbon capture and storage commercialisation. It also helps to provide certainty to investors across a range of generation technologies and protection to consumers.

Scenario-based analysis

12. The baseline for DDM analysis represents a plausible outcome of Electricity Market Reforms, characterised by a diversified supply mix[36] and an assumed carbon emissions intensity of 100gCO2/kWh in 2030, which is an illustrative level of decarbonisation in the power sector, consistent with previously published EMR impact assessments.

13. Dispatch modelling is sensitive to a number of such assumptions (e.g. around inputs, methodology), which influence the capacity and generation mix realised under different scenarios. This outcome therefore represents a specific state of the world and is not intended to be a prediction or forecast about what the future is expected to be.

Input assumptions

Fossil fuel price assumptions

[35] http://www.decc.gov.uk/en/content/cms/news/pn12_0146/pn12_0146.aspx

[36] Diversification reflects (in part) the objective of support for the development of a portfolio of low-carbon generation technologies, in order to reduce the technology risks associated with the decarbonisation objective for the power sector

DECC's fossil fuel price assumptions are used in the DDM. Details can be found at

https://www.gov.uk/government/publications/fossil-fuel-price-projections-2014

Carbon Prices

The DDM uses DECC's appraisal values for carbon, as set out in the URL below.

https://www.gov.uk/government/publications/updated-short-term-values-used-for-modelling-purposes-2014

In addition to this the Carbon Price Floor is included in the model following the trajectory set out in the government's response to the consultation on the Carbon Price Floor:

http://www.hm-treasury.gov.uk/d/carbon_price_floor_consultation_govt_response.pdf

Technology Assumptions

Cost and technical data for new plant is taken from DECC's Electricity Generation Costs 2013 report for all renewable and non-renewable technologies. Details can be found at:

https://www.gov.uk/government/publications/electricity-generation-costs

Electricity Demand

The DDM uses Electricity Demand from the 2014 Updated Emissions Projection (UEP). These can be found in Annex C of the following link:

https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2014

Note: The UEP numbers are then adjusted downwards by 2.7% before use in the DDM model as they include Northern Ireland, while the DDM models Great Britain alone. Northern Ireland is reflected in the modelling through the analysis conducted by National Grid and the System Operator Northern Ireland (SONI).

Limitations of the modelling

14. There are important limitations to the modelling. Two significant ones from a security of electricity supply perspective are:

    - It assumes perfect foresight of demand. This means that the model finds that the economically efficient capacity level is close to zero. In practice demand is uncertain and the risks to building too little are greater than the risks of building too much, so the economically efficient capacity level is higher in reality.
    - It doesn't model the effects of plants needing to be warm in order to operate. As a result, it may underestimate the likelihood of scarcity events or prices rising above marginal cost when margins are wide. It also fails to reflect the effect of cash-out reform on the degree of plant warming or on the market incentives to invest in plant faster ramp-up times.

Capacity Market

15. To capture the effect of capacity agreements, both the allocation process (auction) and the effect on the wholesale electricity market have been modelled.

16. The auction process is modelled by a ‘stack’ of the capacity offered into the auction. For simplicity we have assumed that all existing and potential new generators are bidding in their de-rated capacity to the auction. However, low-carbon plant in receipt of payment through the RO and CfD is not eligible for capacity payments.

17. The bid prices for each generator are calculated based on the required additional revenue to cover their operating costs, extend the plant lifetime or build a new plant.

18. In each year, the auction ‘stack’ requires as inputs the volumes of capacity offered by each generator or new project and the prices at which this capacity is offered. Each generator offers at a price which makes their generation or project profitable, de-rated by the standard capacity credits in the Electricity Market Reform modelling. From this ‘stack’, the auction clearing price for each year is calculated, along with which plant receive the reliability contracts.

19. The key parameters for a modelled Capacity Market are:

- For delivery years 2018/19 onwards, the volumes of capacity procured by the central buyer are sufficient to deliver 3 hours lost load per year. This is open to all eligible capacity and there is no differentiation based on flexibility.
- CfD and RO-funded plant as well as interconnected capacity are assumed to not receive capacity payments, although their capacity credit is taken into account when setting the level of capacity to contract for.
- Agreement length: 1-year agreements for existing plant and fifteen-year agreements for new plant.
- Once a generator has physically closed it cannot re-enter the auction in a later year – i.e. the possibility of mothballing capacity has not been considered.
- Generators offer their capacity factors into the auction.
- All plant operating under the Limited Lifetime Opt-out (LLO) mechanism must close in 2023.

Annex B: Commercial Modelling

1. The commercial analysis assessed a range of known potential interconnector projects under both Ofgem's Cap & Floor and merchant route. The analysis focused on estimating the project and equity internal rates of returns as well as likely capital structures including the minimum debt able to be raised under project finance facilities.

2. The sources for the key assumptions were:

Merchant Revenues

- *New* electricity interconnection to GB – operation and revenues, February 2014, Baringa, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/322005/new_electricity_interconnection_to_gb_operation_and_revenues_baringa.pdf

Cap & Floor revenue allowances

- Based on Ofgem Cap & Floor Financial Model available online, and adapted accordingly depending of the specific project being analysed.
- See "Simplified Financial Model Illustrating Proposed Regime Design for NEMO" from https://www.ofgem.gov.uk/publications-and-updates/cap-and-floor-regime-regulated-electricity-interconnector-investment-application-project-nemo

CM clearing prices

- Based on the analysis by Baringa, 2014, see above. Cross-checked with latest DECC modelling in the September 2014 Impact Assessment.

Project specific data (Costs, commissioning year, construction stage)

- Various public sources including Ofgem's consultation papers
- Complemented by latest market intelligence and investor feedback
- Note: Specific assumptions won't be made available due to commercial sensitivity/ on-going regulatory assessment

Financial assumptions

- Cost of debt: In line with recent Ofgem study, commissioned from CEPA, https://www.ofgem.gov.uk/ofgem-publications/59246/cepa-report-financeability-study-cap-and-floor-regime.pdf
- Complemented by latest market intelligence and investor feedback
- Senior Debt Repayment: Flat debt repayment and interest profile
- Grace period during construction for principal repayment and interest
- Gearing: Variable – depended on assured long term revenue

Macroeconomic assumptions

- Flat CAPEX amortization throughout full lifetime of asset
- 2% annual inflation
- Neighbouring interconnected country assumed to have the same regulatory, macroeconomic and tax environment than GB