The Capacity Remuneration Mechanism in the SEM

Prepared for Viridian

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Executive Summary

On 5 February 2014, the Regulatory Authorities (RAs) of the all-island electricity market published a Consultation Paper laying out proposals to reform the Single Electricity Market (SEM). This Consultation Paper (the “SEM Consultation”) considers proposals to reform the nature and scope of energy trading arrangements within the SEM, and also reviews different options for reforming the Capacity Remuneration Mechanism (CRM) used to remunerate generating capacity.

Viridian has asked us to consider the RAs’ proposals to reform the CRM that currently applies throughout the all-island market. In particular, we were instructed to consider the alternative options proposed by the RAs, and to address some specific questions about the design of CRMs in general.

Electricity Market Problems

We are conscious that a perfectly competitive electricity market (an “energy-only” market that puts a market-clearing price on all sales of electricity) will encourage efficient investment in capacity and will secure generator adequacy. Discussion of CRMs therefore begins by observing how an electricity market departs from this ideal form, and identifying a solution that mitigates the ensuing problems.

If every consumer had a smart meter offering information on half-hourly electricity prices, they could choose what quality of supply they wanted to receive or the maximum price they were prepared to pay. In practice, consumers (the “demand side” of the electricity market) do not participate fully, due to the technical difficulty and cost of doing so. Instead, if demand ever exceeds the available supply, the system operator decides when and where to cut off consumers’ demand in blocks (“load shedding”). Generator adequacy therefore possesses some characteristics of a “public good”, which leads to under-provision of a good or service unless a central authority intervenes.

The intervention required to encourage efficient investment in generator capacity can be as simple as putting a high price on electricity (the “Value of Lost Load” or VOLL) whenever load is actually shed. However, whilst the political process might put a high price on load shedding, experience suggests a tendency for regulatory and political authorities to cap actual electricity prices below VOLL (explicitly or implicitly). This tendency may be driven purely by short term political considerations, but it also reflects the difficulty of distinguishing between a genuine shortage of capacity and anti-competitive behaviour. Many regulators have concluded that their electricity markets are not sufficiently competitive to allow

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1 The all-island electricity market is jointly regulated by the Commission for Energy Regulation (CER) in the Republic of Ireland and the Utility Regulator (UR) in Northern Ireland. Together, they constitute the Regulatory Authorities that oversee the Single Electricity Market.

2 In discussing electricity markets, it is conventional to refer to “capacity” and “generator capacity” as if they were interchangeable. In principle, “capacity” can and should include “demand-side measures”, i.e., load shedding arranged on a commercial basis. In practice, the extent of demand-side measures is limited by technology (the need to cut off all a consumer’s demand, rather than fine-tuning their consumption) and/or cost (the time, money and effort required to liaise with a consumer over which forms of demand to sacrifice at what price levels).
unfettered rivalry between generators. If any generators have a large market share, regulators may put an explicit cap on prices, to prevent excessive pricing. If any large generator is state-owned, its competitors may suspect it of acting in a non-commercial manner. In response, regulators may regulate the formation of generators’ offers to the market, thereby implicitly capping electricity prices.

In any case, the mere threat of such interventions in electricity pricing is enough to reduce the expected long run revenue from generation. That deters investors from building enough generation capacity and requires some other mechanism to provide the “missing money”.

These problems are compounded in electricity markets that are small relative to the minimum size of investment in generator capacity. Any single investment can turn a capacity shortage with very high prices into a capacity surplus with very low prices. Investors may therefore wait until a shortage is particularly acute before they invest, to avoid causing prices to collapse. Coordinating such a strategy across all potential investors is difficult, especially if liquid forward markets do not emerge. The possibility of over-investment acts as a further deterrent to investment.

The RAs have identified these and similar concerns when deciding how the all-island electricity market should work. In 2007, when the market was set up, and again when the RAs conducted a Medium Term Review between 2009 and 2011, they concluded that the small size of the market, the market power of dominant companies, and the inherent regulatory/political risk would all deter efficient investment in generator capacity. The solution adopted then was to include a Capacity Remuneration Mechanism within the SEM. These particular problems have not disappeared since the RAs last looked at the electricity market, which implies that some form of CRM is still required. The RAs would therefore need strong arguments to support a decision to remove the CRM now, to persuade investors that conditions had changed, and that the decision was not driven purely by short term political considerations. Otherwise, the RAs would inject new and additional regulatory risk into investors’ perceptions of the all-island market, with adverse consequences for investment and consumers’ interests.

The RAs use the alleged incompatibility of the existing CRM with the EU Target Model as a reason for reviewing its design. In practice, it may not be necessary to redesign the CRM fundamentally to make it compliant with the Target Model. It may be sufficient simply to replace the ex post component of the capacity payment with an ex ante component, or to exclude interconnectors from the mechanism.

**Important Factors in Any Evaluation of Options for the CRM**

The SEM Consultation discusses seven “options” for a future CRM in the all-island market. Those options are:

- 1: “Strategic Reserve”
- 2a: “Long Term Price Based”
- 2b: “Short Term Price Based”
- 3: “Capacity Auctions”
- 4: “Capacity Obligations”
The “strategic reserve” differs from the other options, as it would “target” any payment for capacity on a few selected generators, rather than making a “market-wide” payment to all available capacity. Such schemes might help to increase or to maintain the level of “flexible capacity”, which is useful for meeting the system operator’s statutory duty to operate the electricity system securely from minute to minute and hour to hour. However, strategic reserve does not contribute to generator adequacy, since the capacity it supports simply displaces or “crowds out” investment in other capacity.

We understand that the system operator might wish for a strategic reserve, because the growing volume of intermittent generation from renewable energy sources is increasing the hourly fluctuations in output from dispatchable plant. However, such considerations concern short term “operating reserve”, not the provision of adequate generator capacity to meet demand in the long term. In a competitive market, long term security of supply is not the responsibility of the system operator, but it is of direct interest to consumers and to the regulator (acting on behalf of consumers). Discussion of strategic reserves – or rather, short term operating reserves – should not be allowed to distract from consideration of generator adequacy.

This discussion highlights the need to set out clearly the reasons for having a CRM. Elucidating the reasons will also be important to ensure that the proposed CRM passes the scrutiny of the European Commission under the rules on State Aid. The current CRM was introduced with the aim of promoting investment in generator adequacy. Conditions in the SEM have not changed so radically since the last time the RAs reviewed it. The SEM still appears to face several of the problems that afflict electricity markets and make a CRM necessary:

- The market is small and open to abuse of market power by dominant producers;
- Investors receive imperfect signals from electricity prices, because of transactions costs (e.g., lack of demand side participation, and insufficient “granularity” of energy prices) and the lack of liquid forward markets;
- Prices still vary widely, so generator adequacy suffers from the “missing money” problem owing to a variety of actual and threatened interventions in the market. These interventions include explicit price caps, regulation of generator bidding, and regulatory and political interventions that deny generators the opportunity to recover their costs.

The options in the SEM Consultation are not spelled out in enough detail to permit a full evaluation at this stage. However, no proper evaluation or selection process could be carried out without giving consideration to these key factors. For example:

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3 Available capacity eligible to receive a market-wide CRM includes generation fired by fossil fuels, but also renewable capacity receiving separate support under environmental policies, to the extent that renewable capacity relies on revenue from sales of energy and capacity to cover its total costs.
The “price-based” options (2a and 2b) will have to take into account the instability of a small market and the need to remedy problems of market power, so in practice they are likely to incorporate a demand curve (price-quantity trade-off).

The “quantity-based” options (3 and 4) are also likely to incorporate a price-quantity trade-off, for exactly the same reasons. In this respect, the “price-based” and “quantity-based” options will be very similar. However, the “price-based” options offer a real-time or spot price for capacity. In contrast, the “quantity-based” options comprise a kind of forward contract for capacity, with a penalty for non-delivery imposed in real time (rather like a spot price). Designing a quantity-based forward contract for capacity raises all the same questions as a price-based CRM (such as the definition of eligible capacity). Any CRM (whether it includes penalty arrangements or not) will require a compliance mechanism (such as enforced testing).

In addition, setting up forward contracts (i.e., quantity obligations) in advance would create a need for market participants to trade their obligations, if their available capacity or capacity obligation change over time. Such trading may be inefficient in a market dominated by a single market participant (especially one that is not subject to commercial pressures). However, if suppliers cannot buy and sell capacity obligations efficiently, they will find it difficult or impossible to compete for new customers. Problems in a secondary market for capacity obligations will therefore hinder competition in the retail electricity market.

Finally, as specified in the SEM Consultation, the “reliability options” (5a and 5b) appear to be nothing more than long term electricity contracts settled financially (“contracts for difference”) against an electricity market reference price. It is not clear what problem these options are intended to solve. For instance, they would not be expected to offer any more revenue than is available from the electricity market, so they do not contribute any of the “missing money”. We note that early versions of the Electricity Market Reform (EMR) in Britain discussed a similar form of contract. However, the latest EMR proposals impose an additional penalty for non-delivery (closer to the concept of VOLL) over and above the electricity price.

From these observations, we conclude that the SEM Consultation has not specified the options for any future CRM in sufficient detail to allow a full evaluation of them. We conclude also that any future evaluation would have to take into account a number of important factors specific to the all-island electricity market, to ensure that it serves not just administrative requirements, but also the interests of consumers.
1. Introduction

1.1. Overview

On 5 February 2014, the Regulatory Authorities of the all-island electricity market (the CER and UR), published a consultation paper laying out proposals to reform the Single Electricity Market (SEM). The “SEM Consultation” considers proposals to reform the nature and scope of energy trading arrangements within the SEM, and reviews different options for reforming the Capacity Remuneration Mechanism (CRM) used to remunerate generating capacity.

Viridian asked us to consider the RAs’ proposals to reform the CRM that currently applies throughout the all-island market. In particular, we are instructed to consider the alternative options proposed by the RAs, and to address some specific questions about the design of CRMs in general.

1.2. Our Instructions

Viridian asked us to:

- describe the requirements set out by the European Commission on the compatibility of CRMs with state aid guidelines; and
- review the options proposed by the RAs for a new CRM, setting out the minimum requirements for evaluating the different options.

To support this review, Viridian asked us to consider the reasons for having a CRM and the conditions affecting its design in greater detail. We therefore:

- outline the conditions in which it would be economically efficient to have a CRM, rather than relying on an “energy-only” market (such as demonstrable and irremediable market failures in the energy-only market), thereby identifying the economic criteria for assessing whether a CRM is necessary; and
- review the case for a CRM in Ireland, in the light of the underlying economics of the system and the requirements set out by the EC and ACER, focusing on whether the specific characteristics of the Irish electricity system (noting the projected surplus capacity out to 2022) provide good reason for instituting a CRM from the standpoint of economic efficiency and the EC’s guidelines.

In addition, on the assumption that considerations of economic efficiency justify the adoption of a CRM, Viridian asked us to propose solutions for key choices in the high-level design of a CRM that meet the economic criteria and are likely to comply with European-level guidance. We set out the questions put to us by Viridian in Appendix B.

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5 Our review of this point will only consider economic interpretations of these guidelines and will not constitute legal advice.
1.3. The Structure of This Report

This report proceeds as follows:

- Chapter 2 provides the background and context to the review of the CRM in the SEM, including the EC State Aid guidelines;
- Chapter 3 gives an outline of the role of a CRM in the Irish market, and answers some questions about its future design;
- Chapter 4 sets out criteria against which to evaluate the options put forward by the RAs;
- Chapter 5 uses these criteria to set out the minimum requirements for evaluating each of the RAs’ options;
- Appendix A provides detailed arguments on the role of a CRM in the Irish market; and
- Appendix B provides detailed answers to the high level design questions put to us by Viridian.
2. Background and Context

This chapter sets out the background relevant to both our review of the need for a CRM in Ireland and our comments on its eventual design. In particular:

- Section 2.1 sets out the context of the CRM in the all-island market;
- Section 2.2 describes the RA’s review of the CRM in the all-island market and sets out an overview of the RA’s views on the future of the CRM; and
- Section 2.3 sets out the constraints set out by the EC State Aid guidelines on the possible design of the CRM in the all-island market.

The current CRM has been in place since the creation of the SEM in Ireland in 2007, justified by, amongst other things, by a need to attract and retain investment in a small market. That investment is needed to meet peak demand, but the CRM is designed to spread its cost over a wider range of periods, including some with a shortage of capacity and some with excess capacity.

The market is currently experiencing a period of excess capacity. According to the TSOs’ assessment, this excess capacity will last for some time, but that conclusion depends on the continuation of existing incentives within the SEM. The RAs’ review suggests that they are minded to retain a CRM (the question remains open for consultation), but that they believe the CRM must be adapted to comply with the EU Target Model. The EC State Aid guidelines set out high level criteria for justifying CRMs under state aid rules. These guidelines specifically require policymakers to explain the need for a CRM before intervening in the market.

2.1. The Context of the CRM in the All-Island Market

2.1.1. The SEM has included an explicit CPM since its creation in 2007

The Regulatory Authorities (the Northern Ireland Authority for Energy Regulation and the Commission for Energy Regulation (SEM) for the island of Ireland in November 2007. They decided to introduce an explicit capacity payment mechanism (CPM) to attract investment, rather than to rely on the implicit reward that generators receive in an energy-only market when prices rise above the short run marginal cost of production. During the design process, they explained the objectives of the CRM:

“This decision is driven by the need to attract timely investment, retain capacity and encourage efficient exit recognising specific characteristics of the all island market. Particularly, the scale of the market, the relative size of new investments and their impact on market dynamics and consequent uncertainty.”

The RAs subsequently comprehensively reviewed the CPM between 2009 and 2011 to assess its performance against its objectives. The RAs concluded that the CRM remained important to the SEM because of its impact on the financeability of generation projects, that the CPM was “generally working well and that there is no compelling need to make major changes to the current design”.  

The CPM operating in the SEM at present allocates an “annual capacity payment” determined by the RAs among all eligible generators participating in the market. It is funded by electricity suppliers. The annual payment is equal to a volume of capacity times the cost of building new capacity, specifically (1) the volume of capacity required to ensure a predetermined standard of security of supply times (2) the fixed cost per kW of the “Best New Entrant”, i.e. a peaking plant. This annual payment is split into twelve monthly “capacity period payments” of varying size. The larger payments fall in months where there is a higher expected loss of load probability (LOLP), and vice versa. These monthly payments are therefore greater during winter months of high demand than during summer months of low demand. Each monthly payment is divided among the available capacity in that month. The more capacity generators make available in total, the less they receive for each kW of available capacity. The current CPM therefore applies a trade-off between price and quantity.

Generators receive a share of the monthly “capacity period payment” for every half hour in which they are available to generate. The total payment to all generators in each half hour is determined by dividing the monthly “capacity period payments” into three components.

- **“Fixed” (30 per cent):** this portion of the monthly payment is allocated across hours within the month in proportion to ex ante forecasts of demand.

- **“Variable” (40 per cent):** this portion of the monthly payment is allocated across hours within each month in proportion to ex ante forecasts of LOLP. Ex ante LOLP is determined in advance of each month by calculating generation margins, which are a function of forecast demand, registered capacity, scheduled outages and forced outages. LOLP is a decreasing function of generation margin.

- **“Ex Post” (30 per cent):** this portion of the monthly payment is allocated across hours within each month according to assessments of ex post LOLP. Ex post LOLP is determined after the end of each month by calculating generation margins as a function of actual demand and actual available capacity. The margin is then converted into a LOLP using the same function as for the ex ante component (although, after the fact, there is actually no probabilistic element to the loss of load).

Some sources of generation in the SEM (namely energy flows across interconnectors and intermittent generators) receive half hourly payments that are proportional to their production of energy, rather than their availability. In the case of interconnectors, traders importing electricity receive a capacity payment, while traders exporting electricity must contribute towards the cost of capacity payments. Intermittent generators using renewable energy sources rely on revenue from energy sales and capacity payments, to the extent that other forms of support do not fully cover their costs.

2.1.2. Security of supply is forecast for the medium-term

The SEM currently has a large surplus of generating capacity which the system operators forecast to last until at least 2023, as shown in Figure 2.1. The system operators forecast that the reserve margin will tighten from a high of 35 per cent in 2015 to 12 per cent in 2023, as demand growth erodes excess capacity on the system. The most recent forecasts show a larger reserve margin for most of the period than at any time in the last four years, principally because forecast demand growth has been revised down over that time. Interconnector capacity has also increased: since 2002 the Moyle interconnector (450MW) linked Northern Ireland with Scotland; in May 2013 the East-West interconnector (500MW) established a second link between Ireland and Wales.

The actual levels of excess capacity that may materialise over the coming decade depend crucially on the redesign of the SEM. The system operators base their forecast of capacity on the existing stock of plant, less plant that has announced its retirement date. If the redesign of the SEM were to threaten the ability of existing plant to cover its costs, for example, by reducing the capacity payment, some plant may retire earlier than anticipated by the system operators. That might turn the forecast excess supply into an actual shortage. We discuss the implications of the current level of capacity on the objectives of the CRM in Appendix A.3.
To calculate generation margins, the Irish TSOs reduce peak demand by the amount of demand served by wind farms. This “wind capacity credit” corresponds to a varying load factor, of approximately 20 per cent for 1,000MW of installed capacity, decreasing to 10 per cent for 6,000MW of installed capacity.\(^\text{12}\)

Thermal plant dominates electricity generation in the SEM. Figure 2.2 shows that, as of 2014, the SEM contains 1,331MW of coal-fired capacity, 5,260MW of gas-fired capacity and 1,503MW of oil-fired capacity.\(^\text{13}\) According to the TSOs’ forecasts, levels of thermal capacity are relatively stable – capacity from coal-, gas- and oil-fired plant is forecast to fall by only 4 per cent between 2014 and 2020. By contrast, intermittent generation is growing rapidly. Between 2014 and 2020 nominal wind capacity is forecast to grow by 65 per cent, from 2,840MW to 4,700MW.

The increase in intermittent generation from wind is likely to contribute to greater reliance on flexible thermal generation to balance supply and demand. As a proportion of installed

\(^{11}\) Eirgrid, SONI, *Generation Capacity Statements* (passim.). The margins presented here are surplus capacity ÷ peak transmission demand.

\(^{12}\) Eirgrid, SONI (2014), page 38.

\(^{13}\) These figures include capacity which can switch between fuel types. We have assumed that both the Moneypoint and Kilroot plants operate as coal-fired units.
capacity, generators defined by the TSOs as “non-dispatchable” or “partially dispatchable” are forecast to make up 82 per cent of the total in 2020, down from 90 per cent in 2014.  

Figure 2.2  
Intermittent Generation Is Forecast To Grow As A Share Of The Capacity Mix  

Source: Eirgrid, SONI (2014); NERA analysis.  
Wind capacity is derated with a 30 per cent load factor.  

2.1.3. Market Power and the CRM  

The all-island electricity market is relatively concentrated by European standards. The Herfindahl-Hirschman Index (HHI) is a measure of market concentration, which ranges between 0 for a perfectly competitive market and 10,000 for a monopolised market. The all-island generation market has an HHI of 2,590, above the level (2,000) at which European rules suggest a merger of any two parties would raise competition concerns.  

Similarly, the supply market is also concentrated, with an HHI of 2,697.

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14 Both calculations and Figure 2.2 use an estimate of wind capacity based on the assumption of a 30 per cent load factor, for illustrative purposes.  


16 The EC merger guidelines state that industries with a post-merger HHI of above 2,000 and a delta (i.e., change in HHI) of above 150 may raise competition concerns. See Guidelines on the assessment of horizontal mergers under the Council Regulation on the control of concentrations between undertakings, Official Journal of the European Union, (2004/C 31/03), 5 February 2004, paragraph 20. US authorities define a “highly concentrated” market as one with a HHI greater than 2,500. See Horizontal Merger Guideline, Department of Justice and Federal Trade Commission, 19 August 2010, page 19.
The largest player in the all-island generation market is ESB, which accounted for 46 per cent of electricity output in 2013 (a market share that may indicate dominance, according to EU guidelines). The other large sources of electricity are interconnector flows (11 per cent), Bord Gais (8 per cent), and Viridian (6 per cent). The supply market is dominated by Electric Ireland (a subsidiary of ESB) which holds a 37 per cent share. The two other largest players are Viridian (26 per cent) and Airtricity (24 per cent). The balance between different players in the upstream and downstream market is illustrated Figure 2.3.

Figure 2.3
The All-Island Market Has One Large Player in Generation and Supply

Figure 2.3 shows that there are sizeable differences between the market shares in each segment. Both Viridian and Airtricity are major retail suppliers of electricity, but their upstream operations provide limited generation. Possible sources to make up this shortfall include independent generators like AES and energy traded over interconnectors (supplied through the gross pool). By contrast, ESB has a portfolio which generates more than enough electricity to meet the needs of its downstream customers. Since ESB is 95 per cent state-owned, its competitors face a risk that it responds to non-commercial incentives in the energy and capacity markets.

These imbalances between generation and retail supply do not affect the outcome of the current CPM in the all-island market, since the payment made to available capacity is determined centrally rather than by downstream market participants. However, the presence of (1) a dominant market player and (2) large imbalances in the supply and demand for

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17 Market share figures on which this calculation is based are quoted are on a generation basis for 2013. Figures taken from ESB (March 2014), Investor Presentation – 2013 Full-Year Results and Business Update, pages 16-17.


capacity are important constraints when considering different designs for a CRM, especially those that rely on capacity markets and trading.

2.2. **The SEM Committee’s Review of CRMs under I-SEM**

On 5 February 2014, the RAs announced a re-design of the SEM as part of implementing the EU Target Model. They call this new market the I-SEM. In order to comply with the EU Electricity Target Model by 2016, the regulators are consulting on reforming various aspects of the market, including its Capacity Remuneration Mechanism.

In their most recent statements, the RAs leave open the question of whether a CRM will still be necessary in the reformed SEM.20 However, the RAs argue that the current mechanism is inconsistent with the Target Model. Cross-border flows across interconnectors receive a capacity payment based on electricity production, but the value of this payment is not known beforehand, due to the ex post component of the payment. The EC Target Model puts more emphasis on cross-border trading in day-ahead timescales, but the ex post component of the CRM appears to be a barrier to market coupling, as it prevents market participants from hedging risks and trading efficiently across borders based on observed price differentials. The RAs therefore state that “to include a capacity price in market coupling would require the capacity prices to be known ex ante (for cross-border trading)”.21 The RAs may decide to retain a CRM. If so, given the parallel proposals to reform energy trading arrangements in the SEM, they intend to reform the form and scope of the current all-island mechanism, to accommodate the requirements of the EU Target Model and to be compatible with EC guidelines on state aid.

2.2.1. **The RAs are considering CRM options**

In the SEM Consultation on the high level design of the reformed market, the RAs put forward a number of options for a future CRM. They set out five design attributes for categorising CRMs (see Figure 2.4):

- **Scope**: whether the mechanism is targeted or market-wide.
  - Targeted mechanisms procure capacity that does not participate in the energy market (or does not participate unless prices are unusually high). The capacity is only used to address a shortage of capacity at times of system stress.
  - By contrast, market-wide mechanisms involve all generators and may include demand-side response, both of which are also free to participate in the energy market.
  - The RAs state that they consider capacity trades under targeted mechanisms (such as procuring strategic reserve) to have more limited “consequences [for] the wider energy market”, but have not investigated their effects in detail.22

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The RAs Are Considering Five Options For A Reformed CRM

**Figure 2.4**
The RAs Are Considering Five Options For A Reformed CRM

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<td>1: Strategic Reserve</td>
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<td>2a: Long Term Price Based</td>
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<td>2b: Short Term Price Based</td>
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<td>5a: Centralised Reliability Options</td>
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<td></td>
<td>5b: Decentralised Reliability Options</td>
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</table>

**Source:** I-SEM Consultation.23

- **Nature of the incentive**: whether the CRM is based on price or quantity. The RAs’ division of CRMs into “price-based” and “quantity-based” mechanisms depends on how the obligation is defined and the method used to remunerate capacity.
  - According to the RAs, a price-based mechanism is any CRM where a value is “attached to capacity and included as an explicit element of the price paid to available generation/demand resources”.24 It does not impose an obligation on generators to deliver capacity into the market, but rewards them for doing so. Within the RAs’ taxonomy, the current CRM in the SEM is an example of a price-based mechanism. The RAs’ definition of a price-based mechanism does not require the price for capacity to be constant. In the current CRM, the revenue for capacity is fixed, and the price per kW of capacity varies according to the quantity of capacity available.
  - Quantity-based CRMs place an obligation on the participant to ensure that adequate generating capacity (or demand reduction capacity) is delivered into the market. Such schemes may include a payment for fulfilling this obligation (or a penalty for failing to fulfil it), determined either administratively or through a market mechanism.

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Timing: whether the price signal provided by a CRM is visible in advance, or only ex post, and when the payments fall due.

- Proposed CRMs in France and Great Britain provide a price signal four to five years in advance of delivery. By contrast, prices in the CRM in Ireland depend on annual reviews but are not fully known *ex ante*, because of the *ex post* component.

- The RAs state that the distribution of capacity payments throughout the year should reflect any seasonality in the value of capacity. They argue that the current CRM system (which sets a fixed annual payment, but allocates more of it to periods where capacity is relatively scarce) allows for a balance between (1) “a short term signal to provide the required capacity during periods of tight capacity margin”, and (2) “the longer term certainty over capacity revenues for generators”.25

Level of intervention: whether the CRM involves setting an explicit capacity target, and what penalty arrangements accompany it. The RAs have stated that:

- they intend to define centrally the target level of capacity, whether they adopt a price-based or quantity-based mechanism;

- the obligation to procure this capacity (if any) may be placed either on the TSO, or on market participants in proportion to their share of peak demand; and

- penalty arrangements (if any) may be either determined by the regulator, or through a market-based contractual approach.

Eligibility: whether participation in the CRM is limited to generators participating in the local energy market, or includes generators located outside that market.

- A key requirement for market coupling is to avoid distorting cross-border participation in electricity markets. Therefore the RAs have concluded that, to comply with the Target Model, “the SEM CRM would have to be set *ex ante* (rather than partially *ex post* as now)”.26

- It is not clear whether the RAs base their reasoning on statements made by the European Commission or on other principles of the EU Target Model. As a matter of economic principle, trade need not be “distorted” even if the value of capacity is only known *ex post*, as market participants can and will trade on the expectation of future revenues.

- The target model requires *day-ahead* market coupling across Europe, but within-day trading of electricity is also feasible in some member states. Within-day prices in European electricity markets may not match day-ahead prices, if conditions change in the meantime. As a result, the flow of electricity from one market to another prompted by day-ahead prices (and market coupling) may not appear profitable from an *ex post* perspective. However, the source of the difference between day-ahead and within-day energy prices is the change in conditions, rather than any distortion or inefficiency. It is not obvious that within-day revisions to the price (or value) of

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capacity are conceptually different from within-day revisions to energy prices, and may just reflect changing conditions.

- However, the *ex post* element of the CRM in Ireland may create a risk that is not be present in electricity markets in other member states, where the reward for capacity is fixed in advanced through energy trading or *ex ante* capacity mechanisms. As a result, traders will be unable to hedge certain risks of cross-border trading.

In practice, the RAs’ taxonomy only refers to the major decisions that might fall within the remit of the RAs themselves. As Figure 2.4 shows, it only reduces the range of potential CRMs to a number of general approaches, each of which contains more than one possible design. The advantages and disadvantages of adopting any one approach (as defined by the RAs’ taxonomy) will depend on the precise details of the proposed designs. Bearing in mind the limited information available at this stage, we set out in Chapter 3 a high-level appraisal of the options and the minimum requirements for the RAs’ future evaluation of each option.

### 2.3. EC State Aid Rules

State Aid describes benefits granted through state resources, which favour certain undertakings or the production of certain goods, in a way that distorts (or threatens to distort) competition within the internal market, and that affects trade between Member States. The European Commission rules on State Aid for generation adequacy (currently in draft form) place limits on when market intervention using state resources, through CRMs, is justified. 27

The emerging EC rules require that any future CRM aimed at ensuring generation adequacy in the all-island market must meet the following criteria. 28

- **Objective of Common Interest**: a CRM must be aimed at a clearly defined generation adequacy problem. However, the EC notes that introducing a CRM may contradict the objective of phasing out subsidies to fossil fuel generators. The EC requires that Member States must first consider alternative means of ensuring generation adequacy, such as increased demand-side management and interconnector capacity.

- **Need for State Aid**: a CRM should not be used as a substitute for addressing deficiencies in the energy market, such as a lack of market coupling or an effective ancillary services market. In its assessment, the EC will consider whether demonstrable market or regulatory failures have given rise to a generation adequacy problem, citing the example of wholesale price caps. There is a presumption that Member States must take steps to remove these market failures before a CRM can be justified. 29

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29 [See EC Staff Guidance (2013), Generation Adequacy in the internal electricity market – guidance on public interventions, Working Document, Commission Staff, SWD(2013) 438 final, 5 November 2013, page 16: “Member States are encouraged to identify and, where possible, remove regulatory and market failures […] before intervening in the market. In particular […] the removal of wholesale and retail price regulation […] has an important role to ensure generation adequacy”.]
Background and Context

- **Appropriateness**: A CRM should remunerate solely the provision of capacity available to generate electricity, and not the sale of electricity. A CRM should allow different technologies, with different lead times, to meet the need for generation adequacy. However, State Aid “should in principle not reward investments in generation from fossil fuel plants unless it can be shown that a less harmful alternative to achieve generation adequacy does not exist”\(^{30}\).

- **Incentive Effect**: A CRM must incentivise the “beneficiary to change its behaviour … which it would not do without the aid”, and not merely subsidise activities generators would undertake regardless.\(^{31}\) The EC suggests the incentive effect can be identified by comparing levels of activity with and without intervention – it cites the example of examining the NPV of investment with and without aid.\(^{32}\)

- **Proportionality**: A CRM must result in its beneficiaries earning a rate of return which is “considered reasonable”.\(^{33}\) The EC advocates a “bidding process on the basis of clear, transparent and non-discriminatory criteria” to ensure this outcome, noting it must be open to existing and new generation.

- **Avoidance of Negative Effects**: A CRM must be designed in such a way that any capacity can participate if it is able to address the generation adequacy problem, including different technologies and operators in different Member States. The CRM should be designed to allow a sufficient number of generators to participate “to establish a competitive price for the capacity”, and should not impose negative effects on the internal market such as export restrictions.\(^{34}\) In addition (in a departure from the general rules on competition and state aid), the EC guidelines suggest that any CRM should favour low carbon generators when they are technically and economically equivalent to alternative options.\(^{35}\)

Of the above criteria, the first two create an obligation to demonstrate that a CRM is needed to solve established market failures. We consider the implications of these criteria in the context of the all-island market in Appendix A. The following four criteria are concerned with the detailed design of a CRM that is compliant with the law on state aid. We address these criteria in our answers to the specific questions put to us by Viridian in Appendix B.

The State Aid guidelines rely on economic criteria such as identifying market failure as a means to establishing the need for a CRM. The clear lesson from the State Aid guidelines is that the economic conditions of the all-island electricity market are important to the design of any capacity payment and need to be considered in combination with any legal constraints.

\(^{30}\) EC Draft Guidelines (2013), page 56, paragraph 212.


\(^{34}\) EC Draft Guidelines (2013), page 57, paragraph 218.

\(^{35}\) EC Draft Guidelines (2013), page 56, paragraph 219 (e).
3. CRM Justification and Design

This chapter outlines the arguments on which we rely subsequently when we examine the RAs’ seven “options” for a reformed CRM and set out the minimum requirements for evaluating them. In particular:

- Section 3.1 outlines the arguments for keeping a CRM in the all-island generation market. The full detail supporting these arguments can be found in Appendix A; and
- Section 3.2 considers certain questions put to us by Viridian about the design of a CRM. We support these arguments in detail in Appendix B.

The CRM currently operating within the all-island market is an attempt to overcome the market failures that prevent an energy-only market from delivering an efficient mix of generation. These market failures are still relevant to the choice of CRM. When considering the design of a reformed CRM (or any alternative market arrangement), the RAs should consider the coverage of the scheme, the need to provide efficient signals for market entry and exit, avenues for abuse of dominance, and its compatibility with the EU Target Model.

3.1. The Need for a CRM in the SEM

Energy-only markets are in principle capable of delivering a generation mix that is both allocatively efficient (demand is met at least cost every half hour) and dynamically efficient (sufficient invest takes place to ensure future demand is met optimally). Because generator capacity is limited, prices in an energy-only market will occasionally rise to the “Value of Lost Load” (VOLL) in times of scarcity. At those times, demand is met by an efficient mix of generation and load-shedding. Such “price spikes” are needed to offer peaking plants and other generators the opportunity to recover their fixed costs. (See Appendix A, Section A.1.)

In practice, market failures mean that energy-only markets may not encourage efficient investment in generator capacity. Significant political and regulatory risk diminishes the value to investors of markets that rely on prices rising to VOLL. Regulatory and political institutions tend to react adversely to price spikes, and many energy market rules explicitly cap wholesale prices below the level of VOLL. Even if such explicit caps are absent, as long as regulators remain averse to price spikes, market participants will face a risk that regulators intervene to prevent high prices from occurring. This threat of regulatory intervention places an implicit cap on prices. Any cap on prices (whether explicit or implicit) creates a problem of “missing money” – a shortfall in the revenue required to cover the cost of investing in generator capacity. (See Appendix A, Section A.2.1.)

Limited participation by consumers (the demand-side) in energy markets is likely to compound this problem. The limited scope for consumers to participate in energy markets means that the demand curve for electricity is very “inelastic”, i.e. demand does not respond to price movements. Inelastic demand makes electricity prices more volatile, heightening the regulatory and political risks surrounding the reliance on high prices, diminishing expected revenues and deterring investment. An inelastic demand curve also facilitates the exercise of market power, which invites more regulatory interventions. (See Appendix A, Section A.2.2.) Limited participation in the associated market for long-term contracts means that the forward curve of prices does not give investors reliable signals about the future need for capacity. (See Appendix A, Section A.2.3.)
The problems above are prevalent in a small market, especially one characterised by large investment in long-lived assets. In a small market, problems in co-ordinating “lumpy” investment mean that investors require long periods of capacity shortage and high prices before they will build new capacity, in case their investment produces a long period of excess supply and low prices. (See Appendix A, Section A.2.4.)

A review of the SEM suggests that these problems are still likely to afflict the all-island energy market. In particular, the presence of an explicit cap on wholesale prices (as well as the recent history of regulatory intervention) is likely to create a “missing money” problem. In addition, the presence of a potentially dominant (and state-owned) player in the wholesale market may increase the perception by market participants that prices are effectively capped. (See Appendix A, Section A.3.)

A CRM is an attempt to overcome the failure of the energy-only market to prompt adequate investment in capacity, by replacing revenues from occasional energy price spikes with a smoothed payment for capacity.

In 2007 the RAs recognised that conditions in the SEM justified such a mechanism – a position that they reaffirmed as recently as 2012 in their Medium Term Review. There seems to be no reason to believe that conditions in the SEM have changed sufficiently to remove the need for a CRM. Even if the SEM could manage without a CRM in the short term, it would be opportunistic (and therefore harmful to investment) to remove the CRM now, with the intention of re-introducing it later, if it became necessary. (See Appendix A, Section A.4.)

3.2. High Level Design Questions

On the assumption that some sort of CRM is required in the SEM, Viridian asked us to address some high level design questions about its design.

3.2.1. Coverage of the scheme

The EC and the RAs both view “targeted” CRMs favourably, suggesting that they “distort” the market less than “market-wide” CRMs. However, this view betrays a misunderstanding of the economics of electricity systems. Targeted schemes may help with the system operator’s need for the flexible generation required to provide short term operating reserves. However, targeted “strategic reserves” do little to aid generator adequacy, i.e. the provision of enough capacity to meet peak demand. They merely distort the selection of generator capacity by displacing or “crowding out” cheaper forms of generation capacity.

Inclusion of “targeted” options in the RAs’ list highlights the need to understand the purpose of a CRM by identifying a problem with the electricity market, and to the check that the proposed CRM will remedy the identified problem. Following such a process will help to meet the EC’s criteria for State Aid. (See Appendix B, Section B.1.)

3.2.2. Provision of efficient exit signals

A well designed CRM will induce efficient exit from the market, as well as efficient entry into it. When the legacy of historical investment decisions means that there is excess capacity in the market, it is efficient for plant with high costs to retire. The plant with the highest costs may not be the oldest plants. The selection of plant to retire is likely to be
relevant in the SEM, which has a 30 per cent generation margin at present. (See Appendix B, Section B.2.)

3.2.3. Abuse of dominance (market power)

The design of the SEM includes a number of safeguards against the abuse of market power – both withholding supply to increase prices and predatory (or merely non-commercial) reductions in prices to increase market share. These safeguards arose from a recognition that some generator companies have large market shares and/or are state-owned and therefore subject to non-commercial pressures. The rules of the SEM energy market – in particular the Bidding Code of Practice – were designed to give investors more confidence that market outcomes would reflect the interplay of supply and demand in competitive conditions.

Similar considerations will arise in the design of any CRM. In particular, other capacity markets have broken down the distinction between “price-based” and “quantity-based” schemes, by introducing a trade-off between price and quantity – otherwise known as a demand curve. Careful consideration of market power and measures to mitigate its effects should form part of the design process for the future CRM or any alternative market arrangement. (See Appendix B, Section B.3.)

3.2.4. Compatibility with EU Target Model

Finally, the EU Target Model neither permits (nor forbids) the introduction of a CRM, but the design of any CRM must be compatible with it. The current CRM in the SEM is unlikely to meet that standard, because the ex post component militates against risk management in day-ahead cross-border trading. The risk it creates acts as a barrier to hedging and to efficient trade across borders.

In practice, the desire to promote cross-border trading may not require a fundamental redesign of the existing CRM. It may be enough to replace the current ex post element with a payment fixed ex ante (e.g., by adjusting the shares of each component). The RAs might also follow the example of the UK government in excluding foreign generators and traders from participation in the CRM, so that trade between the SEM and the British market is driven by the difference between energy prices alone. (See Appendix B, Section B.4.)

3.3. Conclusion

The arguments that we have outlined above (supported in Appendix A of this report) suggest that there is no reason to think that the market failures recognised by the RAs in 2007 and 2012 are no longer present in 2014. To the extent that these market failures are well understood, have already received the concerted attention of the RAs and are not soluble by alternative means, a CRM remains a necessary feature of the reformed SEM.

The answers to the high level questions on CRM design that we have outlined above (and detailed in Appendix B) suggest that careful consideration is needed to ensure the chosen CRM is fit for purpose within the all-island market. In particular, we note that the coverage of the CRM needs to be justified with reference to the market failure it is aiming to address. Any evaluation must also consider the need to induce efficient exit, to mitigate market power, and to remove barriers to cross-border energy trading and risk management.
4. Evaluation of Options

4.1. The RAs’ Seven Options

As discussed in Chapter 2, the RAs have identified seven “options” for a reformed CRM. These options are set out in the SEM Consultation paper (and repeated in Figure 2.4 above) under the following titles:

- 1: “Strategic Reserve”
- 2a: “Long Term Price Based”
- 2b: “Short Term Price Based”
- 3: “Capacity Auctions”
- 4: “Capacity Obligations”
- 5a: “Centralised Reliability Options”
- 5b: “Decentralised Reliability Options”

These seven options are likely to provide the basis for future consideration of CRM designs. However, the framework used to define these options does not appear to have been applied comprehensively. Some items mentioned in Table 9 of the SEM Consultation (such as the “Timings and distribution of the CRM”) are missing from taxonomy in figure 16 on the next page. Some lists included in both Table 9 and Figure 16 are not exhaustive or mutually exclusive (such as the list of items under “Level of Intervention”). In paragraphs 10.7.1 to 10.15.5, the SEM Consultation provides only high level descriptions that do not specify each option in full.

The options have not therefore been developed to be point where anyone can conduct a comprehensive evaluation of the system best suited to the all-island SEM. Indeed, the SEM Consultation assesses each option by a different set of criteria, which prevents a proper comparison of their relative merits.

A proper evaluation of CRM options would require a full specification of each design. However, we understand that the RAs have given themselves limited time to design, evaluate and select the appropriate option. This process may require some options to be evaluated in more detail than others, but it would be undesirable to overlook potential major advantages or disadvantages. Below, therefore, we set out our recommendations for the next stage in the process as guidance on the evaluation of individual options.

4.2. Relevant Factors

For each of the seven options, we begin by setting out our understanding of the relevant CRM and of any areas that still require clarification. We then note important factors that the RAs would have to take into account when developing and evaluating each option. The list of the factors relevant to these options derives from the analysis presented in Appendix A and Appendix B. In those appendices, we identify the following concerns.
4.2.1. The problem to be addressed by the CRM

The first concern to be considered in any evaluation of options is ensuring that a CRM is fit-for-purpose. In Appendix A, section A.2, we discuss a number of reasons for electricity markets to include a CRM, which we summarise here:

- Instability of prices, due to the small size of the all-island electricity market relative to minimum-scale investments in generation capacity;
- Lack of liquidity in forward contract markets, limiting the ability of generators to manage risks;
- The corresponding threat to generator adequacy due to the “missing money” problem caused by:
  - Explicit caps on the energy price imposed by the SEM rules and the Bidding Code of Practice;
  - Implicit caps on the energy price imposed by the threat of (1) regulatory and political intervention in markets and of (2) policies that deny generators the opportunity to recover costs;
  - Inadequate provision of pricing signals due to transactions costs, e.g. lack of demand side participation, and insufficient disaggregation (“granularity”) of energy prices by time and location.
- Selection of particular types of generation to meet specific purposes (by location or for flexibility), due to the lack of granularity in market price signals.

Appendix A, Section A.3, provides more detail on the market failures that are likely to affect the SEM, which provide the justification for a CRM. We illustrate there how a CRM provides an alternative to relying on revenue from the energy market when prices spike to VOLL. A CRM should provide generators with a replacement source of revenue, which is needed to cover their fixed costs. Renewable generators may also rely on this payment, to the extent that the direct subsidy they receive under various environmental policies is insufficient to cover their costs without an additional payment for capacity.

Understanding and identifying the reason(s) for introducing any CRM will be an important part of any evaluation process, and it will help deal with the EC’s guidelines on State Aid. Indeed, providing a good reason for including a CRM within the SEM would fulfil a large part of the EC’s own requirements for State Aid. Questioning the purpose of each option will therefore be important, to ensure that the design of the new I-SEM, and of its CRM in particular, is tailored to conditions within the island of Ireland, and is not merely selected to circumvent administrative barriers.

4.2.2. Minimising regulatory/political risk

The problems listed in the previous section derive, to a large extent, from regulatory and political risk. A CRM will not solve these problems unless it minimises regulatory and political risks, either by reducing it or by offsetting it:

- A CRM reduces regulatory and political risks if it removes the source of the risk (such as reliance on occasional high electricity prices) and replaces it with a less risky alternative (such as – for example – a capacity payment spread over many periods).
A CRM offsets regulatory and political risks if it merely provides additional revenue for long term investments in capacity, whilst leaving the existing risks unchanged.

In assessing whether a proposed CRM minimises regulatory/political risk, it is necessary to consider the following aspects of its design:

- The potential for over-remuneration of capacity, in the short term or over the long term, within the design of a CRM; and
- The risk inherent in the mechanism (whether automatic “demand curves” or discretionary changes to parameters) used to adjust a CRM in the light of over- or under-provision of capacity.

These factors may require a trade-off between the provision of accurate short-term price signals and the desire to avoid extreme prices. Assessing the benefit of different trade-offs requires detailed knowledge of the design of any CRM. If such details are not available, any option to be evaluated must at least include draft rules that show how it will address the regulatory/political risk used to justify its adoption.

### 4.2.3. Mitigation of market power in the supply of capacity

The energy component of the all-island SEM is constrained by rules intended to mitigate the impact of market power. Concerns over market power arise both from the incentive for private sector generators to raise or lower prices if that would increase their profits, and from the ability and tendency of state-owned generators to lower prices for political reasons. The same concerns should inform the design and evaluation of any CRM.

The EC guidelines on State Aid and a number of statements by the RAs put great emphasis on the desirability of using markets to set the price of capacity. In practice, capacity markets will not produce efficient prices or desirable outcomes if they allow individual providers of generating capacity and demand-side resources to move prices significantly by expanding or contracting their supply. As noted above, the price-elasticity of the demand for capacity has a major influence over the degree of market power possessed by individual sellers (and buyers). In some conditions, “inelastic” demand for capacity (e.g. a fixed obligation) gives many suppliers a major influence over the price of capacity. A CRM may produce a better outcome if it dampens the change in prices caused by any variation in supply (e.g. by including a demand curve). As with regulatory/political risk, achieving this aim may require some trade-off, this time between providing accurate short-term price signals and preventing the manipulation of prices.

### 4.2.4. Cross-border trade

The motivation for the current review is the desire to promote more efficient trade in electricity across borders between member states. The EU has developed a target model as a way to promote trade by harmonising institutions. In practice, though, the target model provides for a wide range of discretion over whether to adopt a CRM, and how it would look.

The target model focuses on the closer integration of cross-border day-ahead trading (with the integration of within-day trading following in future, perhaps). For the all-island SEM, its crucial border is with the British electricity market. The success of this integration therefore
depends on the extent to which the form and timing of day-ahead energy prices and capacity incentives (of whatever form) match on both sides of the border.

The Electricity Market Reform (EMR) in Britain is still being developed, which makes it difficult to coordinate the design of the I-SEM with it. At this point, the EMR proposals include provision for market-wide capacity contracts procured centrally four years in advance. These contracts will be backed up by a substantial penalty for not providing energy from contracted capacity when requested by the system operator. The penalty represents the real-time incentive to provide capacity, although cross-border trading may only be feasible up to the day-ahead stage. Only capacity located in Britain will be able to acquire a capacity contract. Interconnectors will not be eligible to participate in the capacity market.36

Given the uncertainty surrounding the final design of the EMR, it would be difficult, and potentially unwise, to choose a mechanism solely for the sake of harmonising cross-border trade with Britain. Details of the British system may change before and after implementation of the EMR and the I-SEM. When evaluating options for a CRM in the all-island market, therefore, it will be necessary to consider how any proposed CRM would fit different schemes – in particular, how it can be adapted to fit (1) day-ahead trading and within-day trading; (2) a British market that does not pay for capacity provided by interconnectors; and (3) different levels of penalty for not providing capacity in Britain.

**4.2.5. Summary**

From the discussion above, we conclude that any evaluation of different CRM options must, at the very least, address the following questions:

- What is the purpose of the proposed CRM, in terms of the market failure it is intended to remedy – instability, illiquidity, “missing money”, or transactions costs?
- How exactly will the proposed CRM remedy that market failure?
- Will the CRM reduce (or offset) existing regulatory/political risks? What new regulatory/political risks does it introduce?
- How will the proposed CRM mitigate the impact of market power (both withholding supply to raise prices and expanding or maintaining supply to lower prices)?
- How will the proposed CRM manage cross-border trading with the currently proposed EMR and how can it be adapted to accommodate specific changes in: (1) day-ahead versus within-day trades over the interconnector; (2) different eligibility rules for interconnector capacity in Britain; and (3) different levels of penalty for non-performance in Britain’s capacity market?

With the detail available at this stage, it is not possible to answer all of these questions for every option identified in the SEM Consultation. In the next section, therefore, we comment on the RAs’ options, as defined so far, using these questions to identify the minimum requirements for any subsequent evaluation.

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5. Minimum Requirements for Evaluation of Options

The RAs may take forward a subset of the options identified in the SEM Consultation. We therefore offer the following comments on each option as far as possible on a standalone basis. This approach entails some repetition of key points and cross-references to other options, but that is unavoidable.

5.1. Strategic Reserve (Option 1)

This is the only option that is “targeted” (limited to specific sources of capacity) rather than “market-wide” (applicable to all eligible capacity). Adoption of this option therefore requires particularly careful consideration of the reasons for having a CRM in the all-island electricity market.

The decision to include a CRM in the original design of the SEM sprang from concerns over future security of supply (generator adequacy) due to: the small size of the market; the potential for the market to oscillate between surpluses and shortages; and the regulatory/political risk attached to a reliance on extreme electricity prices to attract investment. The design adopted in 2007 also acknowledged the “missing money” due to the Bidding Code of Practice and an explicit price cap (by adopting a solution which made up for the “missing money” whilst carefully avoiding over-remuneration). In turn, those restrictions on bidding reflected concern about the market power of dominant players within the electricity sector. Any decision to proceed with a “strategic reserve” targeted on a limited number of generators would have to explain why all these concerns were no longer relevant.

5.1.1. Effect on regulatory/political risk

Although other electricity markets have sometimes adopted a strategic reserve, the grounds for maintaining one remain obscure. As we explain in greater detail in Appendix B, Section B.1, a strategic reserve does not contribute towards generator adequacy, contrary to the suggestion in the SEM Consultation.\(^\text{37}\) Instead (as the SEM Consultation goes on to recognise), strategic reserve enables generators of one favoured type to displace other (usually cheaper) generators of a different type. The favoured generators are then held off the market until all other sources have been exhausted.\(^\text{38}\)

Conditions within the SEM have prompted discussion of a supposed need for more flexible generation, to deal with the growing volume of output from intermittent renewable sources. However, flexible generation would not be held off the market and used only as a last resort. Instead, it would be used whenever other generators were available but unable to respond quickly enough to offset the change in output from renewable sources. At such times, there is no loss of load and it would be inefficient to price electricity at the Value of Lost Load.\(^\text{39}\)


\(^{38}\) I-SEM – High Level Design (2014), page 109, paragraph 10.7.3.

\(^{39}\) I-SEM – High Level Design (2014), page 109, paragraph 10.7.3.
The system operator typically has a legal obligation to ensure short term security of electricity supply. To meet the need for flexible generation, the system operator might have to increase the volume of its contracts for short term operative reserve (the ability to follow load, minute by minute, a conventional system service). However, increasing short term operating reserve does not improve long term generator adequacy (the ability to meet peak load, when it occurs). Indeed, there is no analogous obligation placed on the system operator to ensure security of supply in the long term (which is the purpose of a CRM). Discussion of the system operator’s need for short term operating reserve should not therefore distract from consideration of long term generator adequacy.

If the RAs decide to proceed with a new electricity market that only contains a strategic reserve and no other CRM, it will be important to explain to market participants how the new market is intended to encourage investors to build and maintain capacity. As noted in Section 2.1.2, the current forecast of a capacity surplus lasting for several years depends implicitly on maintaining the current level of incentives. If the RAs plan to remove the current CRM and not to replace it with any market-wide alternative, it will be essential to review the forecast of capacity and to check that the new market will achieve long term security of supply, in the form of generator adequacy.

The answer to this last question – how the new market will achieve long term security of supply - must set out a convincing and stable vision of the SEM’s future. The SEM Consultation suggests that the new market would rely on high electricity prices at times of shortage. However, it is not obvious that this approach is any more credible in 2014 than it was in 2007 or 2012. It is no solution to this problem to propose removing the CRM now, during a period of capacity surplus, and retaining the option of re-introducing a CRM when capacity shortages are imminent. A CRM is a de facto price cap imposed in lieu of high electricity prices; it only provides incentives to invest if it is maintained over the cycle of capacity shortage and surplus. Any proposal to remove it now and to introduce it later would be an opportunistic regulatory policy that prevents cost recovery, raises regulatory risk and discourages investment in the long run. Any evaluation of this option would have to find some way to dispel this impression that it is part of an opportunistic regulatory policy.

Overall, therefore, we find it hard to envisage any conditions in which the creation of a “strategic reserve” is the optimal response, or even an effective solution to a problem. We appreciate that the system operator may anticipate a rising demand for flexible generation, but that demand concerns the level of short term operating reserve, not long term generator adequacy. Any decision to proceed with a strategic reserve and no other CRM would have to be backed up by a rigorous explanation. In particular, the RAs would have to explain to investors why none of the reasons for introducing a market-wide CRM in 2007 were now relevant, to avoid creating a perception of opportunism and increasing regulatory risk.

### 5.2. “Long Term Price Based” (Option 2a)

The SEM Consultation distinguishes between “price-based” and “quantity-based” CRMs, which is a false dichotomy in practice, or at least a mis-labelling of the key decision. Box 1

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below examines this distinction and concludes that it refers to the difference between a “spot price” for capacity and “forward contracts” for capacity.

**Box 1: Price-Based and Quantity-Based CRMs**

The SEM Consultation distinguishes between “price-based” and “quantity-based” CRMs, which is a false dichotomy in practice, or at least a mis-labelling of the key decision. In practice, no CRM sets out a fixed price or a fixed quantity in perpetuity, because setting the price or quantity at the wrong level can result in (respectively) the wrong quantity or an unacceptable price of capacity emerging in the market.

Some CRMs have automatic adjustment mechanisms in the form of a demand curve, which specifies a trade-off between price and quantity. CRMs that have no demand curve require the relevant authority to make discretionary changes to key parameters (and CRMs that include a demand curve are not immune from such tinkering with the rules).

In practice, the SEM Consultation distinguishes between:

1. CRMs that offer a kind of real time market for capacity that pays a “spot price” at the time when capacity is provided; and
2. CRMs that set up a commitment or “forward contract” for capacity offered in advance, backed up by a spot or real time penalty for non-delivery.

**5.2.1. Effect on regulatory/political risk**

Option 2a seems to fall into the first category, a “spot price” for capacity, since it offers a payment for capacity at the time when it is provided. However, the SEM Consultation explains that the total annual pot of revenue available for capacity payments would be calculated (and split into monthly pots) in advance. As with the current CRM, owners of available capacity would then divide this monthly pot between them. This scheme incorporates a demand curve to the extent that a surplus of capacity will depress the spot price – the amount paid out to each unit of capacity – and vice versa. We consider the demand curve implicit in this proposal, and in the current CRM, in more detail in Appendix B, Section B.2.2.

The SEM Consultation regards this type of CRM as a spot price (i.e., “price-based”) system, because it assumes that there is no obligation or penalty for under-performance, except the loss of revenue at the current capacity price. However, the Consultation discusses the effects of deviations between forecast and actual capacity (and demand). Such deviations seem to imply a pre-commitment. In any case, even a system which pays for actual capacity (“ex post”) might impose penalties on generators who repeatedly declare capacity available (and collect capacity payments), but who then provide no output when requested.

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41 I-SEM – High Level Design (2014), page 111, paragraph 10.9.2.
42 I-SEM – High Level Design (2014), page 111, paragraph 10.9.5.
5.2.2. Effect on cross-border trade

The SEM Consultation also suggests that interconnector users would benefit from offering capacity (when delivering power into the SEM) or pay for using capacity (when exporting power to Britain) “if the ex ante capacity price is added to bids into the [Day-Ahead Market]”. However, it is not clear that including the payment per MWh of available capacity in the price per MWh of electricity is efficient. Under the current proposals for EMR in Britain, electricity exported from Ireland to Britain would not earn a capacity payment of any kind. The evaluation would have to examine the potential distortions caused by this approach.

In any case, unless this CRM is viewed as a development of the existing scheme which requires no further approvals at European level, it will need a convincing explanation of the reason for including it in the SEM. It appears to be aimed at strengthening incentives to invest by compensating for “missing money”. To show that it can achieve this aim, the supporting documentation would have to demonstrate that it provides a stable mechanism – ideally a more stable mechanism than relying high energy prices to encourage investment.

5.3. “Short Term Price Based” (Option 2b)

Option 2b also falls under the heading of spot price, using the distinctions made in Box 1. Indeed, this option moves the determination of capacity payments closer to real time, by using a formula related to current estimates of scarcity (a “regulated scarcity rent function”).

Whereas option 2a dispenses with the ex post element of the existing CRM, option 2b relies on it entirely. The SEM Consultation describes a final calculation undertaken ex post based on actual availability and demand. If the result is intended to mimic the current ex post calculation, it provides an odd basis for rewarding capacity. Ex post, the value of capacity is either zero (if supply exceeded demand) or the difference between the energy price and VOLL (if demand exceeded supply). A loss of load probability is a prediction about the future; calculating it ex post with actual data produces a hybrid concept that has no economic meaning.

5.3.1. Effect on regulatory/political risk

Any evaluation of this option will have to consider the regulatory/political risk of relying on a potentially volatile ex post estimate of capacity payments. If the CRM is intended to reduce or offset regulatory/political risk, it will be necessary to show how an ex post capacity payment provides a more stable and reliable source of revenue than the alternative energy price. The SEM Consultation proposes that the capacity price would be “fully responsive to the capacity margin”. However, whilst this approach strengthens incentives to provide

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capacity when it is needed, it reduces investor certainty over future revenues, makes prices volatile in the short-term and enhances market participants’ ability to raise capacity prices by withholding capacity (or to lower capacity prices by keeping more capacity available).\footnote{I-SEM – High Level Design (2014), page 113, paragraphs 10.10.6 – 10.10.8.} Thus, any evaluation of this CRM would have to assess the effects of more “responsive” capacity prices on regulatory/political risk, the exercise of market power, and investment in security of supply.

\subsection*{5.3.2. Effect on cross-border trade}

As with option 2a, the SEM Consultation proposes to include this capacity price in bids into the day-ahead electricity market. This allows the SEM Consultation to claim that interconnector users will benefit from (or pay for) capacity appropriately. However, no economic rationale for this adjustment to SEM electricity prices is spelled out.\footnote{I-SEM – High Level Design (2014), page 115, paragraph 10.11.6.} This aspect of the design will require detailed attention, before any evaluation is feasible.

\subsection*{5.4. “Capacity Auctions” (Option 3)}

According to the distinctions made in Box 1, option 3 uses forward contracts auctioned off by a central authority and enforced by a real-time penalty for non-delivery which could be “as high as VOLL”.\footnote{I-SEM – High Level Design (2014), page 115, paragraph 10.11.6.} The SEM Consultation suggests that this type of CRM is to be found in the proposed capacity mechanism for Britain, but that description overlooks the current proposals for penalties.\footnote{I-SEM – High Level Design (2014), page 114, paragraph 10.11.1.} Whereas early versions of the EMR foresaw penalties based on energy prices (rising to VOLL during a capacity shortage), the latest proposals anticipate a penalty rate fixed somewhat lower than VOLL, in conjunction with a cap on any individual market participant’s total annual penalties defined as a multiple of its annual capacity payments. The SEM Consultation omits these details, but recognises the reason for them, namely that some providers may be unable to bear the risk of high penalties, causing them not to take part in the auction.\footnote{I-SEM – High Level Design (2014), page 115, paragraph 10.11.6.} The penalty aspects of the design are crucial and will have to be spelled out before any meaningful evaluation can be carried out.

\footnote{The Electricity Pool of England and Wales, which operated from 1990 to 2001, applied this kind of mark-up to day-ahead energy prices, using a formula which replicated forward market pricing based on a (truncated) view of future possible spot prices. The formula assumed that the future spot price would be either the System Marginal Price (SMP) calculated from generator bids, or the Value of Lost Load (VOLL). In the former case, generation would be sufficient to meet demand, but in the latter case load would be lost. The respective probabilities of each case where therefore (1 - LOLP) and LOLP, where LOLP was the estimated “Loss of Load Probability”. The resulting formula was a probability-weighted average – SMP.(1-LOLP) + VOLL.LOLP – which represents an estimate of a forward price. The formula was shown differently in the Pool Rules as SMP plus a mark-up equal to LOLP.(VOLL-SMP), leading some readers to misinterpret the mark-up as a capacity payment. It is possible that the description of option 2b is subject to the same misinterpretation.}{47} I-SEM – High Level Design (2014), page 113, paragraphs 10.10.6 – 10.10.8.

{48} The description of option 2b is subject to the same misinterpretation.
5.4.1. Effect on regulatory/political risk

As with all the options, the effect of option 3 on regulatory/political risk requires careful consideration. The SEM Consultation suggests that option 3 will provide “a relatively stable environment for capacity investment”, but its stability depends on the methods used to determine total capacity requirements and for defining eligible capacity.\(^\text{52}\) The stability and transparency of a contract auction can be undermined by discretionary changes to rules such as the definition of eligible capacity and the required quantity of capacity.

As in any mechanism, the eligibility rules must establish the amount of capacity that generators of each type can provide, and the penalties for not doing so. These rules need not place the same requirements (and impose the same penalties) on generators using different technologies. The SEM Consultation mentions (but does not describe) the effect of the penalty arrangements on regulatory risk.\(^\text{53}\) Such effects would have to be examined in detail, if the purpose of the scheme is to reduce or offset regulatory risk.

5.4.2. Effect on market power in the supply of capacity

This option anticipates users taking on contractual obligations in advance, so they must be able to trade their obligations, to reflect changes in their sell-side offers (available capacity). Without such trading, energy companies would not be able to adjust their portfolio of generation capacity, which would restrict long term competition in the wholesale electricity market.

In 2007, there were severe doubts about the degree of competition and the level of liquidity in the wholesale electricity market. The SEM therefore forces transparent trading and restricts generators’ bidding, through compulsory participation in the day-ahead market and a Bidding Code of Practice. Given the importance of capacity trading to the success of option 3, and the potential influence of market power and illiquidity, a similar approach to trading would be required in the capacity market. Any evaluation of this option must therefore consider measures to ensure that capacity trading takes place on an efficient, transparent and non-discriminatory basis. The SEM Consultation recognises the need for market power mitigation measures in the original contract auction, but overlooks the need for similar measures to facilitate secondary contract trading.\(^\text{54}\)

Many US mechanisms involve bidding rules that constrain participants’ behaviour in order to mitigate market power. Concerns about the market power of capacity purchasers have resulted in a number of proceedings before the Federal Energy Regulatory Commission (FERC). For example, in 2006 a publicly owned supplier in Connecticut procured additional capacity within the state. Under the terms of its contract, the capacity had to bid in to the New England capacity market at a marginal cost of zero. This practice attracted widespread

\(^{52}\) I-SEM – High Level Design (2014), page 115, paragraph 10.11.10.

\(^{53}\) I-SEM – High Level Design (2014), page 115, paragraph 10.11.11

\(^{54}\) I-SEM – High Level Design (2014), page 116, paragraph 10.11.14
suspicion, with complaints from other market participants that the state of Connecticut was interfering with the auction process in order to depress the capacity prices that consumers in the state would have to pay.\textsuperscript{55} Regulators in the US have since implemented a number of mechanisms to combat gaming, with frequent revisions to the bidding rules. One clearly identifiable example is the existence of Minimum Offer Price Rules (MOPRs) which prevent buyers from offering to sell capacity (or demand side response) at a price below what the regulator deems to be the competitive level. The Connecticut case offers parallels to the situation in Ireland, where a large state-owned company, ESB, may have an incentive to depress the capacity price (or where other market participants may just be concerned that ESB has such incentives). We analyse the issue of market power in the SEM in more depth in Appendix A, Section A.3.4.

US markets also contain bidding rules which constrain the behaviour of bidders in capacity markets. The PJM, for instance, has rules which regulate the bids of all players with “market power”. The rules stipulate that any generators can bid at most the market administrator’s calculation of “net going forward costs” (i.e. the difference between its forecast revenues and costs) into the capacity market.\textsuperscript{56} The market rules define any player whose capacity is pivotal with any two other players as having market power.\textsuperscript{57} The result is that virtually all the incumbent generators have market power according to the PJM’s definition and the bids of all incumbent generators are strictly regulated.\textsuperscript{58} Moreover, New England has an “insufficient competition rule” which abandons the auction in favour of a clearing-price rule whenever insufficient generation is present up to run the auction successfully.\textsuperscript{59} As a result, although capacity markets in the US are competitive auctions in form, in practice they are often administered payments in outcome.

5.4.3. Effect on cross-border trade

With regard to cross-border trading, the SEM Consultation seems to anticipate the same difficulties that led the designers of the EMR to leave out interconnectors from the capacity market. That would leave cross-border trade being driven by the difference in energy prices. Any evaluation would have to take into account the effect of explicit or implicit price caps within each market.

5.5. “Capacity Obligations” (Option 4)

This option is a variant of option 3, in which the buy-side obligation is decentralised and allocated among all the energy suppliers in the market. According to the distinctions made in


\textsuperscript{56} In addition, generators who disagree with PJM’s calculation of net going forward costs can submit their own calculation for approval. See \textit{PJM Manual 18: PJM Capacity Market}, 30 January 2014, Section 5.3.4, page 83, referring to \textit{Open Access Transmission Tariff - Attachment DD}, pages 68-69, Section 6.4, “Market Seller Offer Caps”.

\textsuperscript{57} \textit{Open Access Transmission Tariff}, Attachment DD, PJM, page 68, Section 6.3 (b), “Market Structure Test”.


\textsuperscript{59} \textit{ISO-NE Market Rules}, Rule number: III.13.2.8.2., “Insufficient Competition”.
Box 1, therefore, option 4 uses forward contracts in the form of an obligation imposed on individual suppliers and enforced by a real-time penalty for non-delivery. The individual suppliers can delegate the obligation by signing contracts with generators. That approach raises all of the same questions about the size and nature of the penalty as arose under option 3 (Section 5.4 above), plus a greater reliance on secondary capacity markets.

5.5.1. **Effect on regulatory/political risk**

Option 4 raises many questions about the stability and transparency of the regulatory decisions on the capacity obligations. The SEM Consultation says that option 4 reduces the level of regulatory intervention, compared with option 3, because it decentralises procurement. This statement seems to be incorrect. Under option 3, the procurement exercise might involve regulatory discretion in the selection of winners, but one would hope the selection rules could be applied in a transparent and mechanistic manner. Decentralising the procurement exercise puts selection decisions in the hands of energy companies, but the regulatory still has to define or oversee the calculation of a total capacity requirement (as in option 3) and must in addition determine how this total capacity requirement will be allocated among energy suppliers. That difference does not appear to reduce regulatory intervention. Indeed, unless the RAAs spell out the rules for defining the total capacity requirement and allocating capacity obligations among suppliers, it will be impossible for any evaluation to assess whether or not this option contributes to reducing the regulatory/political risk facing investors.

5.5.2. **Effect on market power in the supply of capacity**

Option 4 also relies on capacity trading, to a greater extent than option 3. It anticipates that suppliers will take on capacity obligations in advance, and procure capacity from generators to meet these obligations. Generators and suppliers must be able to trade the resulting obligations, to reflect changes in both their sell-side offers (available capacity) and their buy-side obligations (the demand of their consumer base). Without such trading, energy companies would not be able to adjust their generation portfolio or to supply customers beyond the level of their available capacity. Obstacles to capacity trading would therefore severely restrict competition in both wholesale and retail electricity markets.

As noted above, concerns over the degree of competition in wholesale markets in 2007 led to restrictions on generators’ bidding in the SEM, through compulsory participation in the day-ahead market and a Bidding Code of Practice. Given the importance of capacity trading in this option, and the potential influence of market power, a similar approach is required in a capacity market. Any evaluation of this option must consider measures to ensure that capacity trading takes place on an efficient, transparent and non-discriminatory basis. The SEM Consultation overlooks this need.

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5.6. “Reliability Options” (5a: “Centralised”; 5b: “Decentralised”)

The SEM Consultation provides only short descriptions of “reliability options” – a term that arose during the earlier stages of the EMR process in Britain. What is remarkable about these descriptions is how little they differ from options already described above.

In terms of Box 1, a reliability option is a “quantity-based” capacity obligation which takes the form of a forward contract for capacity, with a spot penalty for non-delivery of energy when requested. The obligation to procure these forward contracts can be centralised (option 5a) or decentralised to suppliers (option 5b), just like any other capacity obligation (options 3 and 4). The penalty for non-delivery is defined as a “reference price” of energy, such as the day-ahead price. This rule is similar to the penalty under options 3 and 4, which might be “as high as VOLL”, except that the penalty under a reliability option is taken from energy markets instead of being set administratively at a level reflecting the value of energy or capacity.

5.6.1. Effect on regulatory/political risk

Judging by the description in the SEM Consultation, reliability options really are just a forward contract settled like a contract for difference at the current spot or reference price of energy. If sold by auction, they may not offer any additional value over expected energy prices. Offering such contracts three or four years ahead is unlikely to improve investment incentives, as they would not constitute a long-term “bankable” commitment. They offer no additional revenue to offset “missing money” and energy prices will continue to rise and fall unabated, so there is no obvious diminution of regulatory/political risk. Any evaluation will therefore require a detailed explanation of the problem that reliability options are intended to solve and how they address it.

5.6.2. Effect on market power in the supply of capacity

The imposition of long-term obligations creates a need for capacity trading to reflect changes in available capacity and (in a decentralised scheme) retail market shares. Trading is subject to the same problems of market power and illiquidity as the energy market. These problems have been discussed above, in the context of other capacity obligations. It will only be possible to evaluate options 5a or 5b, once the RAs have spelled out measures to ensure that capacity trading takes place on an efficient, transparent and non-discriminatory basis.

5.6.3. Effect on cross-border trade

Finally, reliability options seem to present no problem for cross-border trading, in large part because they have limited impact on any market. However, as noted above, the capacity

63 Even if the total capacity requirement is very high and can only be met physically by building new capacity, it would be cheaper in most conditions to fulfil the contract financially at energy market prices. The expected level of those prices will effectively define the price at which sellers are willing to sell reliability options.
market proposed for Britain under the EMR has moved away from the original concept of a reliability option, whilst the SEM Consultation seems to have retained it. Any evaluation of reliability options will therefore have to take into account the effect on cross-border trade of the differences between the capacity market concepts on either side of the Irish Sea.

5.7. Conclusion

In this chapter, we have described the various options being considered for a CRM in the SEM Consultation and have identified major gaps in the proposed designs. Unless these gaps are filled in, it will not be possible to conduct any meaningful evaluation of the options set out so far.

Allowing for the uncertain design of each option and potential remedies, we have identified certain important questions that any evaluation of options would have to address. Different questions take different priorities with different options. We have therefore identified the most important questions in each case. Unless the RAs have spelled out the design of each option being considered, and answered the questions relevant to each option, no meaningful evaluation is possible.

The list of design tasks and questions identified above is by no means complete, but it represents the minimum requirement for any evaluation. Selection of a CRM will have a major impact on incentives for investment within the SEM. Investment will in turn have a major and long term impact on the cost of generation to consumers. It would therefore be contrary to consumers’ interests to rush the selection of a CRM by ignoring important factors for the sake of administrative convenience.

The current CRM was intended to serve the purposes of the all-island electricity market, by strengthening investment incentives and reducing regulatory/political risk. It appears to have done so. Any future CRM should be designed and selected with the same intention of serving the purposes of the all-island electricity market.

From these observations, we conclude that the SEM Consultation has not specified the options for any future CRM in sufficient detail to allow a full evaluation of them. We conclude also that any future evaluation would have to take into account a number of important factors specific to the all-island electricity market, to ensure that it serves not just administrative requirements, but also the interests of consumers.
Appendix A.  The Need for A CRM in Ireland

As described in Chapter 2, EC State Aid guidelines stipulate that a CRM can only be justified when demonstrable market failures give rise to a generation adequacy problem. This chapter evaluates whether conditions in Ireland meet these criteria such that there remains a need for the SEM to include a CRM. The chapter proceeds as follows:

- Appendix A.1 explains that, in order to deliver efficient market outcomes, energy-only markets rely on potentially volatile peak prices;
- Appendix A.2 outlines the market failures that can afflict an energy-only market; and
- Appendix A.3 examines whether these market failures in the SEM give rise to a continuing need for a CRM to ensure generation adequacy in the Irish context.

A.1. Energy-Only Markets Rely on Volatile Peak Prices to Deliver Efficient Outcomes

In principle an energy-only electricity market can deliver a generation mix that is allocatively efficient and investment in capacity that is dynamically efficient. For this result to hold the market must be (1) “complete” – meaning that every good associated with electricity can be traded – and (2) competitive – meaning that there are enough market participants (and little enough government intervention) so that no one has the power to set prices unilaterally.64

Allocative efficiency occurs, when resources are directed towards their most productive use, and realise the greatest benefits for society, in the short-term. In a competitive energy market, load is served by the mixture of generation technologies and fuels which minimises total cost (both fixed and variable). This outcome is illustrated in Figure A.1, where we show the load duration “screening curve”. Each upward-sloping line represents the total cost of meeting electricity demand from one generation technology and fuel, for different numbers of hours per year. Baseload plant is represented by the green line. It has high fixed costs, but low variable costs, so it starts high at zero hours of generation (on the left hand side) but rises only slowly as its hours of generation increase (from left to right). Peaking plants are represented by the orange line. They have lower fixed costs but higher variable costs. Their total costs start low at zero hours of generation, but rise rapidly as their hours of generation increase. The costs of mid-merit plant, in yellow, sit between those of baseload and peaking plant in every respect. The green line, representing the total cost of running baseload plant, lies above the lines for other generator technologies/fuels initially (at low levels of output). However, the low variable costs of baseload plant make it the cheapest solution for extended operating hours. Mid-merit and peaking plant offer the lowest cost solutions for running different numbers of hours per year.

For demand that only lasts very few hours per year, the least cost way to meet it is by shedding load. Shedding load is valued at the social Value Of Lost Load (VOLL), i.e., the maximum price a customer would be willing to pay to receive one more unit of electricity. Every electricity market should expect to shed a few hours of load per year on average, as

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64 The result is known as the First Fundamental Theorem of welfare economics.
represented by the red area of the load duration curve in Figure A.1. Occasional price spikes, when the real-time value of electricity rises to VOLL, are therefore a feature of any energy-only market that is meeting demand with the efficient mix of generation and load shedding.

Figure A.1
Energy-Only Markets Incentivise Electricity Dispatch At Least Cost

Indeed, such real-time price spikes (or the equivalent rise in expected prices, in trading before delivery takes place) are necessary to cover the fixed costs of peaking units (and other plants). Figure A.2 shows that, for most half hours a year, prices in an energy-only market reflect the cost of production from the marginal source of supply. At peak times, prices rise above the marginal cost of a peaking plant to reflect the scarcity of generating capacity (and the value to customers of a reliable electricity supply). Since, typically, technological constraints or high transactions costs prevent customers from bidding into the wholesale electricity market, VOLL is a maximum price set administratively (usually by governments or regulators) as a proxy for what they would bid. In hours of load shedding, the electricity price rises to the level of this “quasi-bid” and the “scarcity rent” within this high price remunerates the fixed capacity costs of peaking plant. More remarkably, as long as the generation mix is efficient
and the market is competitive, these scarcity rents also remunerate the share of the higher fixed costs of mid-merit and baseload plants that they cannot recover from profits on their sales of energy.\footnote{In this sense, energy-only markets provide an implicit payment for capacity above the short-run marginal cost of production.} In this sense, energy-only markets provide an implicit payment for capacity above the short-run marginal cost of production.

\textbf{Figure A.2}
\textbf{When Demand Is High, Price Spikes Provide An Implicit Capacity Payment}

\textit{Dynamic} efficiency occurs when resources are allocated efficiently over the longer term, including through the efficient choice of investments. A complete energy-only market will be accompanied by a liquid market for risk, which can deliver efficient investment in capacity. As noted above, the price of electricity in an energy-only market will tend to be volatile and to exhibit occasional price spikes. Generators and customers typically do not

\footnote{The mathematical proof of this proposition is long-winded but not complex. It can be found in a number of articles that describe the “screening curve”.}
wish to be exposed to the full risks of this volatility, spurring the development of markets that allocate (“share”) the risks between different parties. Generators who want to secure the recovery of their costs will contract with customers seeking to minimise the risk of high prices, by signing contract for the sale and purchase of electricity at prices agreed in advance (day-ahead, week-ahead, month-ahead, year-ahead, and so on).

When forward markets are a well-developed means of managing risk, generators can observe price signals that indicate in advance the need for new capacity, and can respond by investing. If peak demand is nearing available capacity, then in the future power prices will be expected to rise and to become more volatile. The price of power agreed in forward contracts (and the value of options on these contracts) will then rise. Observing this signal, generators can respond by investing in additional capacity or by keeping older capacity online for longer, offsetting the required investment costs against a revenue earned from delivering energy at prices agreed through forward contracts. Conversely, if there is an abundance of capacity in the market, expected price levels and volatility will fall, signalling to generators that they should retire older units that are uneconomic. In either case, the market will tend towards an efficient outcome (albeit one constrained by the history of previous investment decisions).


In practice energy markets may neither be complete nor competitive and energy-only markets do not necessarily result in efficient outcomes. Instead, deviations from these conditions may arise and are referred to as “market failure”. Energy-only markets may not be complete if some goods and resources are not tradable, such as a secure supply of electricity in times of system stress. Similarly energy-only markets may not be competitive if limited market participation leads to prices that do not reflect the true cost or value of capacity. In practice, energy-only markets are unlikely to deliver an efficient level and mixture of generation capacities for a number of reasons. We list the typical sources of market failure below. These market failures lie at the heart of the reason for adding a capacity mechanism.

A.2.1. Reliability may constitute an incomplete market

In the future, it may be possible to offer every consumer the degree of reliability they are willing to pay for, by calibrating smart meters to disconnect each consumer only when the electricity price rises above a pre-programmed level. With current technology, however, reliable electricity supply has the features of a quasi-public good. It is “non-excludable” (system operators do not possess the means to exclude single users from the market, in response to their willingness-to-pay). It is also “non-rival” to the extent that reliability depends on centralised incentives for investment in generation capacity (in which case, receiving reliable service does not necessarily preclude another also receiving it).

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Note that in economics a “market failure” can only be judged by reference to the ideal standard of an efficient and competitive market, no matter what outcome might emerge from such an ideal. A market failure does not arise just because a market deviates from an outcome considered desirable by market participants or government bodies.
Economic theory suggests therefore that freely negotiated electricity prices will fail to reflect the full social value of reliability, leading to under-provision of capacity. This market failure can be addressed by ruling that electricity prices must rise to the social Value Of Lost Load (VOLL) in times of scarcity. However, as we discuss below, such rules face a number of practical obstacles and are unlikely to resolve the original market failure:

- **Political valuation of VOLL**: in order to provide the socially optimal level of reliability, prices must be allowed to rise to a level at which customers are indifferent between receiving a continued supply and suffering from their load being shed. However, customers do not typically participate in the wholesale energy market, and therefore the value they place on lost load must be determined by a regulator or similar body. The resulting value becomes a *de facto* price cap. VOLL has often been set by reference to surveys of consumers’ willingness-to-pay, so that the level of VOLL approximates the bids that consumers would submit, were they to participate fully in the market. However, politicians and regulators tend to attribute a high (political) cost to outages in the short term, regardless of any long term implications for total (economic) cost of generation. Political (and regulatory) processes therefore tend towards minimising the cost of losing load, rather than minimising the cost of meeting and losing load, which would maximise social welfare. This tendency sometimes results in VOLL being set higher than the true social cost of load shedding. Such outcomes would provide inefficiently high scarcity rents to generators, and encourage inefficient (excessive) entry of new capacity into the market. However, in practice, such outcomes are unlikely.

- **Explicit price caps**: despite the high cost that political (and regulatory) processes tend to attribute to loss of load, regulators and politicians often aim to cap or prevent spikes in wholesale prices. Price spikes in energy markets are politically unpopular. In response, many energy markets impose explicit caps on the prices at which generators may offer to sell their energy. Prices caps can also arise *de facto* from rules that do not allow prices to reflect marginal cost, as is the case in the Great Britain Balancing Mechanism. Low price caps create a “missing money” problem, because electricity prices do not provide the revenue generators need to recover costs. Specifically, if electricity prices never rise much above the short-run marginal cost of a peaking plant then such plants do not recover their fixed capacity costs (and other plants recover less than their total fixed capacity costs). Price caps therefore deter efficient market entry, leading to inefficiently low security of supply and/or more volatile energy prices.

- **Implicit price caps**: many energy-only markets do not have an explicit price cap. However, in practice regulators and politicians remain so averse to price spikes that they would intervene if prices ever rose near to VOLL. Generators therefore adjust their behaviour to ensure that electricity prices never rise high enough to reflect the true value of scarce capacity. Prices are implicitly capped by the threat of regulatory intervention in response to future price spikes. In some markets, generators may use market power to

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67 The Texas wholesale market, ERCOT, is capped at $5,000/MWh and the PJM on the East coast of the United States is capped at $1,800/MWh, to cite two examples.

raise electricity prices at other times, so as to provide the revenue necessary to cover costs. However, such behaviour may be illegal under competition law and distorts incentives to select the correct generation mix. Implicit price caps and/or the reaction of incumbents can also inject risk and inhibit the ability of new entrants to recover the costs of their investment, thereby deterring efficient new entry.

Figure A.3  
Price Caps Introduce A "Missing Money" Problem

The EC staff also identify that price caps create a market failure, leading to inadequately secure supply:

“Explicit or implicit wholesale price caps […] (particularly if set substantially below reasonable estimates of the value of lost load) prevent the market from fulfilling its proper function of matching supply with demand in times of system stress.”

A.2.2. Lack of demand side response

Due to lack of real-time metering for most customer segments, demand for electricity does not respond to prices in the short term (i.e., in technical terms it is “perfectly inelastic”). This condition can result in inefficiency for two reasons:

- **Excessive volatility**: consumers are effectively unable to respond to prices that signal scarcity in the energy market. Faced with the volatile wholesale prices, large industrial users (and even households) might prefer to reduce their electricity demand in times of scarcity at a price lower (or even much lower) than the officially determined VOLL. Without this sensitivity to prices (“price-elasticity”), energy-only markets for electricity are subject to prices that spike too high and too often. This volatility increases the risks to cost recovery faced by generators, and hence the cost of capital for financing investment in generating plant. Ultimately, energy prices faced by consumers rise as a result.

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- Market power: a highly inelastic demand curve facilitates the exercise of market power (setting prices above marginal cost). If wholesale markets are dominated by large generators, then they can exploit the unresponsive nature of electricity demand by offering to sell electricity at high prices. In this situation, demand is not met at least cost, if some generators withdraw cheap capacity and force the use of more expensive capacity.

A.2.3. Poor risk management tools

If markets for the physical supply of electricity are not accompanied by liquid contract markets, generators and customers will not be able to trade and to reallocate the risk associated with future energy sales. In illiquid markets, the prices of forward contracts and derivatives do not accurately reflect expectations of the future electricity price and its expected volatility. An energy-only market may then fail to provide adequate signals to investors of the future need for capacity.

A.2.4. Poor co-ordination of investment in small markets

Many of the problems highlighted above (limited market participants, lack of liquidity) are particularly likely to affect small markets which require investment in large, long-lived assets. Another problem in small markets is co-ordinating the required investment in capacity. In a small electricity market, a single, minimally-scaled addition of generating capacity may be large enough to accommodate demand growth for several years. Co-ordination problems may deter any particular market participant from making this investment (or may delay decisions to do so until high prices make the need apparent), for fear of over-investment that will be unprofitable for many years. This pattern of “lumpy” investment may exacerbate the long term volatility of energy prices, whereby long periods of shortage and high prices are required to prompt investment, which then produces a long period of excess supply and low prices.

An additional co-ordination problem that can afflict small markets with large, long-lived investment is premature capacity additions by a player with market power. Due to the long-lived nature of power plants (25 years or more), and the occasional need for new investment in a relatively small market, a player with market power can forestall entry by others by prematurely constructing new capacity before the price of capacity rises high enough to remunerate a new entrant. With long-lived investment, this strategy can be supported as a credible threat by the incumbent. However, this leads to a lack of entry by competitors and investment that occurs “too often” (with energy sold by the incumbent at a price that is “too high”).

A.2.5. Practical experience

In the United States, the introduction of a CRM in areas such as the PJM and New England was motivated by the “missing money” problem created by explicit price caps. The political constraints on electricity prices (which emerged from older, regulated systems) were

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A.3. Evidence of the Continuing Need for a CRM in the SEM

As noted earlier, there is currently surplus generating capacity in the SEM. However, in common with many electricity markets, the Single Electricity Market (SEM) suffers from market failures like those set out in Appendix A.2. The market failures identified would require a capacity remuneration mechanism that addresses the specific problems identified below, in order to ensure continued adequacy of supply.

The market failures identified above mean that electricity prices in an energy-only market will not rise as high as VOLL at times of load shedding, when the value of capacity is greatest. This limit on energy prices at crucial times will cause investments in capacity to receive too little revenue (either in actual fact, or in expectation). The lack of revenue discourages investment in capacity, producing an inefficient trade-off between investment and security of supply, whereby load is shed too often. A CRM replaces the missing revenue, and encourages a more efficient level of investment. The resulting quality of service depends on the trade-off between the cost of investing in peaking capacity and the Value of Lost Load. Suppose a generator designed to meet peak loads has an annual fixed cost of €30,000/MW per year. It can cover this cost in an energy market with a low valuation of VOLL and a relatively high number of hours of lost load, for example if the market reaches €3,000/MWh in 10 hours per year. In a market with a high valuation of VOLL, it will cover its costs with relatively little lost load, for example if the energy price reaches €10,000/MWh in 3 hours per year. Different estimates of the cost and VOLL will give different levels of lost load. In every case, the revenue from selling energy at VOLL covers the cost of investing in enough peaking capacity to achieve the relevant level of lost load. However, if energy prices are prevented from rising to VOLL (or are expected to be capped below VOLL), the market must provide equivalent revenue from another source, or else investment will be inefficiently low. CRMs provide one source of revenue to replace the revenue that is missing from an imperfect energy-only market.

The current surplus of generating capacity does not indicate that a CRM is no longer necessary. The purpose of a CRM is to spread the cost of meeting peak demand over a wider range of periods, including some with a shortage of capacity and some with excess capacity. Simply removing payments without removing the market failure is an “opportunistic” form of regulatory intervention which will lead to under-compensation of past investment, as well as a heightened sense of regulatory risk and possibly even greater market failure. To be effective, capacity mechanisms must be stable and long-lived.

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A.3.1. The current SEM has an explicit price cap and bidding rules, leading to a “missing money” problem

The Bidding Code of Practice requires generators participating in the Single Electricity Market to submit offers to generate electricity at their Short Run Marginal Cost (SRMC) of generation. Generators must also submit accurate technical data for each individual unit, indicating the cost of starting it from a cold state, its ramp rate and the cost of running at a zero load factor. The System Marginal Price, which generators receive for their output, reflects the SRMC of the marginal (i.e., most expensive) unit called to meet demand in each half hour (plus any associated start-up, ramp-up or zero load costs). The System Marginal Price cannot exceed a price cap, currently set at €1,000/MWh. The price cap therefore also defines the maximum offer any generator can submit.

The Bidding Code of Practice is designed to mitigate market power in the small and highly concentrated Irish market but it, along with the explicit price cap, introduces exactly the “missing money” problem identified in Appendix A.2.1. The RAs currently estimate that VOLL is €10,898/MWh. Assuming they have correctly measured VOLL, there is at least €9,898/MW of “missing money” in the SEM during hours of load shedding. At some times, this shortfall will be even higher, if the Bidding Code of Practice requires generators to submit offer prices that are even lower.

The System Marginal Price in the SEM does not therefore recognize the social value of lost load. This market failure will lead to the under-provision of capacity and hence reliability. The EC would like the explicit price cap and the implicit constraint on generator offer prices to be removed, but that would expose the market to the exercise of market power. Assuming that (1) the RAs and other Irish government bodies have done everything they can to enhance competition in the electricity market and (2) that there are no other less distortionary remedies for competition problems, a CRM can provide a useful remedy for the failure to permit economic pricing of electricity at peak times, by providing generators with an alternative payment for capacity.

A.3.2. Regulatory risk means prices may be implicitly capped

In Ireland, as elsewhere, generators face the threat of regulatory intervention that places an implicit cap on energy prices. Such threats are undefined, but face generators at all times and constitute a permanent risk to their ability to recover their costs.

In the United States, legal obligations on regulators to ensure a reasonable prospect of cost recovery constrain the ability of regulators to behave opportunistically. Just as importantly, administrative procedures for regulatory decisions are defined in long-standing laws, highly developed, open and predictable. However, such principles and procedures are much less

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73 SRMC is defined in terms of opportunity cost - “the value of the benefit foregone by a generator in employing that cost-item for the purposes of electricity generation, by reference to the most valuable realisable alternative use of that cost-item for purposes other than electricity generation.” Single Electricity Market Committee (13 March 2014), Bidding Code of Practice, paragraph 7.


76 See Administrative Procedures Act 1946.
well developed in European electricity markets, including the Irish one, due to the relatively short-lived experience of liberalisation and privatisation. As a result, market participants in Ireland have less protection (than market participants in the United States) against potentially opportunistic regulatory or political intervention to lower customer bills.

Even if regulatory discretion has never actually been exercised opportunistically to date, the threat of such interventions can still prevent electricity markets from reaching an efficient outcome. The mere potential for opportunistic intervention may be enough to deter investment and to result in inefficient market outcomes.

In any case, the observed behaviour of regulators may gradually heighten or diminish the perception of regulatory risk. In this context, it should be noted that regulators in the SEM have proven willing to change established arrangements in ways that deny the recovery of costs that market participants were expecting to recover. For example:

- In 2010, the CER disallowed costs in the regulated retail segment that had been “legitimately incurred”, in order to keep end-user prices low. 77 The CER disallowed ESB PES’s “K-factor” (an adjustment for revenue over- or under-recovered in a previous price control) in its supply price control of 2011-12. The revenues lost as result of this decision were very significant: €178.3 million was disallowed, around 155 per cent of ESB PES’s regulated annual turnover. 78

- In 2011, the government in the Republic of Ireland introduced a new tax (the Carbon Revenue Levy or CRL) to claw back the value of EU ETS allowances passed through into electricity prices and given to the generators for free. The CRL was a variable (opportunity) cost of generation, but the CER directed generators not to include it in their bids into the SEM. Ultimately, two generators went to the Supreme Court in order to get the decision overturned and to be allowed to recover their costs. 79 The legal costs associated with challenging this decision were recovered and, importantly, the Supreme Court agreed with the generators that the costs of the CRL were to be included in all future bids by generators into the SEM. However, the financial costs of the previous illegal decision by the CER (incurred over the historic period of the CRL) were not recovered.

- In 2013, SEM Committee reviewed and revised its interpretation of how the gas transport costs paid by generators were reflected in their offer prices in the SEM. The CER then published a decision to force the gas transmission company to withdraw within-day tariffs for the sale of exit capacity. 80 That decision (in conjunction with another decision limiting secondary sales of exit capacity to generators) would have made it impossible for generators in the Republic of Ireland to include the cost of gas transmission exit capacity in their offer prices (which would have prevented some generators from recovering these

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costs). In February 2014, the CER reversed this decision, but not for reasons connected with protecting generators’ ability to recover costs.\footnote{CER Decision on Gas Access Products and Tariffs, Notification to Industry, CER, 20 February 2014. The CER’s grounds related to the level of revenue that the gas transmission company was managing to collect from gas-fired generators, among others.}

It is therefore difficult to argue that the SEM is insulated from any perception of regulatory risk and the resulting market failure. On the contrary, the SEM appears to be prone to regulatory interventions that deny cost recovery, like many other European electricity markets. In addition, the all-island market currently includes an explicit payment for capacity. Removing this element from the design of the reformed SEM would increase the perception by market players of regulatory risks to cost recovery. Therefore, continuation of the CRM (in some form) is likely to be justified – or even required – to avoid introducing further regulatory risk and market failure.

The decision to add a CRM to the energy market of the SEM was intended to enhance the credibility of investment incentives, by providing a form of capacity remuneration that was more stable in the long term. The CRM’s design seeks to exchange volatile peak pricing signals for lower and more stable energy prices, augmented by a stable capacity payment. The CRM’s purpose would be undermined, and the credibility of long term incentives weakened, if the RAs adopted a policy of introducing a CRM during any period of anticipated capacity shortage (thereby capping energy prices and limiting returns to investment), and removing the CRM during any period of anticipated capacity surplus (whilst letting energy prices fall and reducing returns to investment).

A.3.3. There is little liquidity in forward markets

The SEM is a gross pool, through which all major generators sell, and suppliers purchase, all the electricity generated to meet total demand. A forward market has developed to manage the risk around future price levels in this market through the trading of “contracts for difference” (CfDs). If the System Marginal Price exceeds the strike price agreed in these CfDs, the generator makes a payment to the supplier equal to the difference in price times the contract volume. Conversely, if market prices fall below the strike price, the supplier compensates the generator. The net effect of the CfD working alongside the SEM is to stabilise the total payment from supplier to generator.

The RAs oblige both ESB and Power NI to offer a certain quantity of their output in advance through “directed contracts”. They and others also trade in “non-directed” CfDs. The RAs last reviewed the liquidity in this market in 2010, when they found that traded volumes of CfDs of all sorts had fallen by approximately 30 per cent since the levels observed in 2008/09 (although some of this fall may be explicable by the fall in total demand over the period).\footnote{SEM Market Power (2010), SEM Market Power & Liquidity – State of the Nation Review: An Information Paper, SEM Committee, SEM-10-057, 23 August 2010, page 43.} A more revealing measure may be the “churn rate” – the volume of electricity traded forward as a proportion of delivered electricity. The RAs found that the SEM had a churn rate lying
well below one, compared to six in the Nordpool market and three in the Great Britain market.\textsuperscript{83}

The available evidence therefore suggests that the forward market for electricity sold in the SEM is likely to be illiquid and uncompetitive, a market failure which can be addressed by a CRM. A CRM cannot make a market liquid or competitive, and the forms of CRM that rely on capacity trading would be subject to the same problems. However, some forms of CRM can substitute for a liquid and competitive forward market by providing generators with a more predictable and stable stream of future income, reducing the risks they face and hence the cost of financing new investment.

\textbf{A.3.4. Potential for market power}

As noted in Section 2.1.3, there is one player (ESB) that is potentially dominant in the all-island generation market. Dominant players inhibit competitive markets reaching socially optimal outcomes, a market failure. In the SEM, this failure of competition can work through several channels. As outlined in Appendix A.2.2, since the demand curve for electricity is highly “inelastic” there is potential for the dominant player to unduly influence energy prices. Since ESB accounts for 46 per cent of generation, it is highly likely that its bids will determine the System Marginal Price in many trading periods. By bidding above (or below) the marginal cost of production, the dominant player can exert effective influence over energy prices.

The Bidding Code of Practice is a measure designed to mitigate this market failure. However, it does not remove it. In this case, since ESB is state-owned, the perception by market participants that it may follow non-commercial incentives can compound this market failure. State-owned companies (even those run at arm’s length) are often perceived to have non-commercial motives, for example minimising wholesale prices. A dominant state-owned company can provide an effective cap on energy prices, by providing electricity at less than its marginal cost. If market participants perceive there to be a risk that dominance will be exerted in this way, then this provides an additional implicit cap on prices (since all believe that the dominant firm will act to lower prices if they rise too high).

\textbf{A.3.5. The “small market” problem is pronounced in the SEM}

Problems arising from the size of the SEM were part of the original justification for a CRM in Ireland (as described in Section 2.1.1 above). Although it is not a source of market failure in itself, the size of the SEM is likely to exacerbate any failures that are present in the energy market. In particular, the minimum efficient scale of a CCGT plant constructed in Great Britain is now about 900MW, and the minimum efficient scale of an OCGT is about 565MW, according to the analysis relied on by DECC to calculate the levelised cost of generation.\textsuperscript{84} The Irish RAs use a 202MW OCGT as their benchmark for the “best new entrant” peaking

\textsuperscript{83} SEM Market Power (2010), page 50.

plant in the all-island market.\textsuperscript{85} In Great Britain a 900MW CCGT represents 1.6 per cent of peak demand.\textsuperscript{86} By contrast, in the SEM this would represent 13.9 per cent of peak demand.\textsuperscript{87} Even a 202MW OCGT represents 3.1 per cent of peak demand.

The size of the SEM is likely to give rise to problems coordinating investment in new capacity, and “lumpy” investment may give rise to volatile prices. Volatile prices, in turn, compound the regulatory risks faced by generators and increase the cost of financing investment. In these conditions, a CRM can smooth the profile of prices earned by generators, by spreading payments that would otherwise occur only occasionally in peak hours over a larger number of peak, near-peak and off-peak hours.

\section*{A.4. Conclusion}

Our instructions from Viridian asked us to review the case for a CRM in Ireland, based on the underlying economics of the system and the EC requirements. We have focused on the EC’s criteria for assessing State Aid, which can be summarised as the need to demonstrate a market failure that gives rise to a generation adequacy problem that cannot be addressed by strengthening the energy-only market.

The presence of an explicit price cap in the wholesale electricity market (coupled with a Bidding Code of Practice that prescribes SRMC bidding) is a demonstrable failure in the energy market to reflect the value of reliable electricity supply (VOLL). Removing the explicit price cap would leave an implicit cap price in place. Removing the explicit and implicit price caps would leave the market exposed to market power, which the RAs have made every effort to minimise.

The real and perceived regulatory risks to cost recovery are likely to exacerbate the problem of under-investment, even if the price cap is removed in the reformed energy market. An illiquid forward market that cannot provide adequate investment signals, and the problems of coordinating large and long-lived investment on a small island (especially in the presence of market power as described in Appendix B.3), provide further evidence of potential market failures in the SEM.

If the SEM relied on an energy-only market, these market failures would result in a generation mix that is neither allocatively nor dynamically efficient, a situation the RAs recognised in 2007 when deciding to introduce a CRM. In their Mid-Term Review in 2012, the RAs implicitly confirmed that these market failures were still in place, since they saw “no compelling need to make major changes to the current design and methodology” of the CRM.\textsuperscript{88} We do not have any reason to think that the market failures recognised by the RAs in 2007 and 2012 are no longer present in 2014. To the extent that these market failures are well understood, have already received the concerted attention of the RAs and there are no

\begin{itemize}
  \item \textsuperscript{85} Fixed Cost of a New Entrant Peaking Plant & Capacity Requirement for the Calendar Year 2013, SEM Committee, May 2012, page 20.
  \item \textsuperscript{86} Peak demand of 55,550 MW for winter 2013/14 taken from Ofgem, Electricity Capacity Assessment Report 2013, Appendix 1, page 64.
  \item \textsuperscript{87} Peak demand of 6,473 taken for 2014 from Eirgrid, SONI (2014), All-Island Generation Capacity Statement- 2014-2023, Appendix 1, page 61.
  \item \textsuperscript{88} CPM – Medium Term Review (2012), page 3.
\end{itemize}
alternative remedies available to them, a CRM remains a necessary feature of the reformed SEM.
Appendix B.  High-Level Design Questions

On the assumption that economic efficiency requires the SEM to incorporate some kind of CRM, Viridian asked us to questions about the design of the CRM, focusing on the following areas:

- **The coverage of the scheme:**
  - The EC and ACER consider explicitly whether the scheme should be a targeted “strategic reserve” or a “market-wide” payment. What are the likely economic effects of a strategic reserve, particular the displacement of other investment and the distortions that targeted payments can introduce, for comparison with the economic effects of a market-wide solution?

- **Provision of efficient exit signals:**
  - Can efficient exit signals (e.g. rewarding more flexible and reliable plant) be incorporated into a price-based mechanism, and if so how?

- **Possible abuses of market power in a CRM:**
  - Given the existence in Ireland of a dominant player that is state-owned an has “deep pockets”, how and to what extent could it use its market power to reduce payments to capacity (and to squeeze out competitors) if capacity payments are determined by an auction or other market based mechanism?
  - Describe a predatory pricing strategy that could be employed by a dominant player; and in what conditions would it be economically rational, if any?

- **Compatibility of the CRM with market coupling under the EU Target Model:**
  - From an economic perspective, what changes would need to be made to the current CRM in the SEM to make it compatible with market-coupling under the EU Target model, in the light of the state aid guidelines?

**B.1. Coverage of the Scheme**

The first step in the RA’s taxonomy divides CRM designs according to the coverage (or “scope”) of the scheme. CRMs can either be “market-wide”, covering the capacity of all power generators, or “targeted”, i.e., only remunerating the capacity of specific generators to be used only during times of system stress.

**B.1.1. The EC’s favourable statements about strategic reserve betray a misunderstanding of economics**

In a recent working document, the staff of the EC discuss the coverage of a CRM. The EC Staff express favourable views towards a targeted “strategic reserve” mechanism. They accept that, “where strategic reserves are used to keep prices low, […] it is] not only not cost-effective but risks seriously distorting the internal market.” However, they state that

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89 EC Staff Guidance (2013).
90 EC Staff Guidance (2013) page 22.
procuring strategic reserve (to be employed in emergency events) does “not affect the market during normal periods”.\textsuperscript{91} Similarly, in the SEM Consultation, the RAs suggest that capacity traded as strategic reserve has limited “consequences [on] the wider energy market”.\textsuperscript{92}

The view that strategic reserve helps generator adequacy without distorting electricity markets is based on a fundamental misunderstanding of the economics of electricity systems, and the role played by strategic reserve. In the short term, targeted schemes can attract new investment in capacity, and increase security of supply. However, in the long term, targeted schemes displace generation that would otherwise have been built, depressing prices but raising total costs. Strategic reserves therefore do little to aid generator adequacy, but do distort the selection of generator capacity.

Figure B.1 illustrates how strategic reserve affects the wider market. The first diagram illustrates the equilibrium level of capacity in an energy-only market, $Q^M$, where long run demand for capacity (the downward sloping black line) meets the long run cost of new entry (represented by discrete blocks of capacity available at different costs). In the equilibrium, the price of capacity settles at the level needed to cover the cost of the marginal unit ($P^M$). Procuring strategic reserve that is “in merit” (such as the block shown in green) does not affect this outcome. While this provides an additional revenue stream for the generator, it does not alter the price of capacity or the quantity supplied. Figure B.1 also shows the effect of contracting with a generator that is “out of merit”, i.e., which costs more than $P^M$ (the block shown in orange). Procuring this strategic reserve puts it at the head of the supply curve, shifts other capacity to the right and causes a slight fall in market prices (to $P'$), which in turn may bring forth a slight increase in capacity (to $Q'$). However, the most important effect is to displace other, cheaper forms of generation that would be “in merit” in normal market arrangements. Procuring strategic reserve therefore raises the total cost of generation, in return for only a slight change in generator adequacy.

\textsuperscript{91} EC Staff Guidance (2013), page 22.

\textsuperscript{92} I-SEM – High Level Design (2014), page 101.
B.1.2. Other policy-makers have recognised the distortionary effects of strategic reserve

When considering options for introducing a CRM in 2011, DECC published an assessment of strategic reserve versus a market-wide mechanism. It ultimately decided against implementing a strategic reserve, noting that:

- strategic reserve “does not deal with the fundamental problem of ‘missing money’”, in that it does not mitigate the effect of explicit or implicit caps on wholesale prices.\(^93\)

Therefore, a strategic reserve system does not address the specific market failure which gives rise to the need for a CRM.

- plants not selected as reserve might shut down, leading to a “slippery slope”, where “more and more plant must form part of the reserve to ensure it remains effective”. 94 This risks “crowding out” efficient investment.
- strategic reserve was unlikely to be technology neutral, as there was little incentive for demand-side response to participate.

NordREG, the group of Nordic Energy Regulators, was similarly critical of the effects on the wider market of TSOs in Sweden and Finland procuring strategic reserves. They agree with the analysis presented in Figure B.1, that “the use of peak load resources [i.e., strategic reserve] is likely to lower the prices in the market”, and that this does indeed create a “slippery slope” where “the incentive to invest in peak load power plants decreases”. 95

B.1.3. Strategic reserve addresses the problem of generation flexibility, not adequacy

The EC and RAs favour targeted mechanisms in a context for which they are not suited, because of a misunderstanding of the distinction between the functions of market-wide and targeted schemes. Capacity markets are targeted at a generation adequacy problem, and mitigating the market failure which means there are insufficient returns to providing capacity. Such schemes must address the incentives to make or to keep capacity available across the market as a whole. Targeted schemes can work to solve a generation flexibility problem, where the problem to be solved is not the volume of generation per se, but selecting the “right kind of capacity” – e.g. flexible capacity – because the market as a whole cannot provide incentives that distinguish between types. For example, in Britain, the Short Term Operating Reserve supports capacity able to start and stop very quickly (more quickly than a half-hourly price can indicate) and located in particular parts of the network (beyond what general transmission tariffs can achieve).

B.2. Provision of Efficient Exit Signals

This section discusses the provision of efficient exit signal in the design of any CRM and addresses the following question put to us by Viridian:

- Can efficient exit signals (e.g. rewarding more flexible and reliable plant) be incorporated into a price-based mechanism, and if so how?

To answer this question, we consider what exit signals are efficient, and how these can be incorporated into a CRM.

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95 NordREG (2009), Peak Load Arrangements – Assessment of Nordel Guidelines, page 15.
B.2.1. CRMs are designed to induce efficient entry into, as well as efficient exit from the market

CRMs are a measure that relieve a generation adequacy problem by providing a payment to available capacity, not a payment based on a characteristic of that capacity (i.e., flexibility). The draft EC guidelines are clear that a CRM is a measure that should be targeted at a “generation adequacy” problem, and that an “appropriate” measure should be open to all technologies that can mitigate the problem (presumably including both flexible and inflexible generators). In most markets, generation adequacy problems arise from a lack of efficient entry. Therefore, CRMs are typically aimed at ensuring there is enough new capacity (either flexible or inflexible) to guarantee security of supply.

However, the legacy of historical investment decisions may mean that the amount of capacity in the market exceeds the efficient level. In these circumstances it is efficient for plant with high costs to retire, when the on-going costs of continued operation exceeds the social benefits of doing so. These circumstances are likely to be relevant to the SEM, where a capacity margin of 30 per cent or greater is forecast to persist until 2018 (and thereafter margins are forecast to remain above 10 per cent until 2023).96

CRM design may prevent efficient exit, for two reasons:

- **Capacity price exceeds social benefit**: the price that generators receive per unit of capacity is too high, such that it exceeds the marginal social benefit of additional capacity. This can occur in a poorly designed CRM (either price or quantity-based), where the regulator sets a fixed price for capacity (or fixed quantity to be procured) that exceeds the optimum level needed to guarantee security of supply. Although the capacity payment may offer remuneration in excess of the social benefit of capacity in the near future, the regulatory authorities must have regard to the wider social benefits of the CRM design. The objectives of a CRM are to provide a stable and reliable capacity payment in exchange for reducing the volatility and level of peak energy prices. Reducing remuneration available through the CRM may threaten this regulatory compact, increase risk for investors, the volatility of prices, threaten future investment and cause plant to exit the market.

- **Ineffective monitoring**: in markets that have a large surplus of capacity (such as the SEM), there may be a number of peaking generators that receive a capacity payment for making themselves available, but are never actually required to generate. Indeed, the plant may not be reliable and/or flexible enough to do so – a situation which can persist if there is ineffective monitoring. These generators are effectively “free riders” who enjoy the benefits of capacity payments without bearing the cost of making their plant available. Nonetheless, the presence of these “free riders” will depress capacity prices without providing a commensurate security of supply benefit. In principle the problem of so-

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called “zombie” capacity can occur in price or quantity based mechanisms, and has frequently been referred to in respect of the quantity-based ISO-NE market.97

B.2.2. Aligning the demand curve and social benefit of capacity

An electricity system may have an inefficiently high quantity of capacity on the system if the price of capacity under the CRM exceeds the marginal social benefit. In principle, this can occur in any CRM design.

We illustrate the concern in the case of the current design used in the SEM on the left hand side of Figure B.2. The total capacity payment to all generators each year is invariant to the actual amount of capacity that is actually available (the areas A, B, and C are all equal). Therefore, when there is an oversupply of capacity (as is the case in C) price falls very slowly in response to excess supply, possibly leading to an over-payment of generators and inefficiently low exit from the market. In practice, the current CRM used in the SEM has a demand curve that is very flat (“price elastic”), even at high levels of capacity.

By contrast, US based mechanisms typically involve a demand curve that has a price of zero (or a low floor price) at some level of capacity (illustrated with the red line on the right of Figure B.2). This demand curve can be incorporated into a “payment-based” mechanism, by reducing the total payment level in response to the amount of generators in the market.

The design of any CRM must solve the market failures identified in the local market and the example of demand curves used in the US may provide a cautionary example against adopting designs successfully applied elsewhere wholesale. In the context of a small market like the SEM, increasing the slope of the implicit demand curve could defeat the object of the capacity mechanism itself. One of the principal motivations for having a capacity payment in

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the SEM is that, as a small market, it might otherwise be subject to spikes and troughs in prices as new capacity was retired or added to the system. For a capacity market to smooth prices in the SEM, the (implicit) demand curve for capacity must decline only gradually. Indeed, steep demand curves also increase the scope for the exercise of market power (as we note in Appendix A.2.2).

Moreover, as noted in Appendix A.3 above, whilst there is currently surplus generating capacity in the all-island market, that does not justify removing capacity payments through introducing a steeply sloped demand curve. Such an “opportunistic” form of regulatory intervention will heighten regulatory risk, and exacerbate the market failure a CRM is designed to address.

**B.2.3. Verification and Testing**

To avoid the problem caused by ostensibly available capacity that does not in fact contribute towards security of supply (“free riders”), a well-designed CRM should also include tough verification standards. Verification that capacity is actually available and generating is an important issue in CRM design, due to the increased role demand-side response is forecast to play in ensuring generation adequacy, as well as the legacy of older thermal plant that is rarely (if ever) called on to generate. Monitoring regimes to alleviate this problem are compatible with either a price-based or quantity based CRM and are used in many US, quantity-based regimes.

- **Forced Testing**: Markets that incorporate CRMs often have well developed forced-testing regimes. For example, in the PJM market generators are obliged to report the net capacity of each unit in both summer and winter. Units that normally generate during the course of both seasons can submit operational data. Units that are not normally called on to generate must conduct an annual test to verify their capability, and submit this to the system operator.\(^{98}\) In practice, and depending on the capacity available in the market, more frequent testing may be required to ensure that capacity is actually available in the Irish context. While forced testing incurs costs, this or some other compliance mechanism, which would also incur costs, is a necessary feature of any CRM.

- **Penalty regimes**: The problem of ostensibly available generation can, in principle be resolved in quantity-based mechanisms through the imposition of penalties for not generating at peak times. For example, the British CRM will auction off agreements to provide capacity (with delivery from 2018 onwards). The agreement places an obligation on the holder to generate (or reduce demand) at times of system stress following a “capacity market warning”. Failing to fulfil the agreement is associated with a stiff penalty. In its most recent impact assessment, DECC outlined plans to impose a £3,000/MWh (€3,600/MWh) penalty on generators that fail to meet their obligation.\(^{99}\) However, penalties are only likely to be an effective measure if they present a real risk to generators: If certain generators are never required to generate, because they are never or

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rarely in-merit, even in peak times, penalties for failure may not incentivise units to exit the system. As a result, units may continue to free-ride by lingering on the system and picking up capacity payments.

The method used to incentivise generators to provide capacity need not be uniform across all unit types. In practice, a CRM is designed to provide a balance of risks and incentives which incentivise the provision of capacity. The ability of generators to respond to those incentives varies, as does their ability to shoulder the risks of potential penalties. CRMs that remunerate intermittent generators, for example, must recognise the fact that their availability varies with time. Currently, intermittent generators in the SEM receive a capacity payment based on their production in a given period (since wind generators, for example, dispatch their entire available capacity). An alternative model, as used in the ISO New England capacity mechanism, is to make a payment to intermittent generators based on their de-rated capacity.\textsuperscript{100} There is currently no penalty in the New England CRM associated with intermittent generators failing to fulfil the obligation.

B.3. Abuse of Dominance

This section discusses possible ways in which a CRM can be used by a dominant market player to abuse its dominance, and answers the following questions put to us by Viridian:

- Given the existence in Ireland of a dominant player that is state-owned and has “deep pockets”, how and to what extent could it use its market power to reduce payments to capacity (and to squeeze out competitors) if capacity payments are determined by an auction or other market-based mechanism?
- Describe a predatory pricing strategy that could be employed by a dominant player; and in what conditions would it be economically rational, if any?

B.3.1. Setting artificially low prices is an abuse of dominance under EC law

EC law prohibits firms that are dominant in a particular market from abusing their position, including “directly or indirectly imposing unfair purchase or selling prices”.\textsuperscript{101} “Predatory pricing” is one way in which a dominant firm use “unfair” prices to abuse its dominance. The EC considers a dominant firm to be abusing its position in this manner when it:

“engages in predatory conduct by deliberately incurring losses or foregoing profits in the short term (referred to hereafter as ‘sacrifice’), so as to to fore-close or be likely to

\textsuperscript{100} For the purposes of the capacity market, intermittent capacity is de-rated to the median output level observed in the previous five years, during certain “reliability hours” in summer and winter. See ISO New England (May 15 2012), \textit{Overview of New England’s Wholesale Electricity Markets and Market Oversight}, page 7; Market Rule 1., pages 51-52, Section III.13.1.2.2.1.1.

\textsuperscript{101} Treaty on the Functioning of the European Union - PART THREE: UNION POLICIES AND INTERNAL ACTIONS - TITLE VII: COMMON RULES ON COMPETITION, TAXATION AND APPROXIMATION OF LAWS - Chapter 1: Rules on competition - Section 1: Rules applying to undertakings - Article 102 (ex Article 82 TEC).
foreclose one or more of its actual or potential competitors with a view to strengthening or maintaining its market power, thereby causing consumer harm.”

Identifying this sort of behaviour is difficult, but the EC requirements imply (at least) the following tests.

- **Dominance**: A dominant firm is able to “behave to an appreciable extent independently of its competitors, its customers and ultimately of consumers”. Market share is used as a first indication of dominance by the EC. Firms with a market share of greater than 50 per cent are routinely regarded as “dominant” in EU competition law, while firms with a market share less than 40 per cent are unlikely to be considered dominant.

- **Sacrifice**: A dominant firm engages in “sacrifice” when it expands output to such an extent (or charges prices that are sufficiently low) that it incurs losses that could have been avoided. If prices are set below average avoidable cost (a proxy for short-run marginal cost), then the dominant firm will incur a loss that could have been avoided by supplying no output at all.

- **Anti-competitive foreclosure**: Foreclosure occurs when the dominant firm’s behaviour depresses prices to the extent that an equally efficient firm cannot compete in the market, because it will be unable to recover its costs. The EC states that this can be assessed by whether the dominant firm is pricing below long-run average incremental cost in the industry (a proxy for long-run marginal cost). Demonstrating that anti-competitive foreclosure has taken place does not require the dominant firm to have actually forced its rivals to exit, or that showing that it intends to recoup its sacrificed profits in the future. All that is required is that as a result of predatory behaviour the dominant firm can expect to increase its market power, whether this is from inducing exit, deterring entry, or merely disciplining rival firms to follow its lead when setting prices.

Predatory behaviour is easier to identify and monitor in an energy market than in a capacity market, since the variable cost of producing electricity is well understood. Predators offer to generate electricity at less than the short run marginal cost of generation. The Bidding Code of Practice rules out this behaviour in the all-island energy market in principle, provided that

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102 EC (24 February 2009), Guidance on the Commission’s enforcement priorities in applying Article 82 of the EC Treaty to abusive exclusionary conduct by dominant undertakings, (2009/C 45/02), paragraph 63.

103 EC (24 February 2009), (2009/C 45/02), paragraph 10.


105 EC (24 February 2009), (2009/C 45/02), paragraph 67.

106 The EC’s criteria is closely related to the so-called Areeda-Turner rule, which states that:

- Pricing above average total costs is not predatory;
- Pricing below average total costs may be predatory, depending on the intent of the alleged predator; and
- Pricing below marginal cost (measured as average variable cost) is presumed to be predatory, unless explicitly justified.

See Areeda, P. and Turner, D.F., (1975), Predatory Pricing and Related Issues Under Section 2 of the Sherman Act, *Harvard Law Review*, 88, pages 697-733. Average variable cost will, in general, equal average avoidable cost (since variable costs are avoidable). However, if the dominant firm incurs additional fixed costs to increase output, then these costs are also avoidable, and AAC will lie above AVC.

107 EC (24 February 2009), (2009/C 45/02), paragraph 67.
it is rigidly enforced. Predation in a capacity market may be more difficult to detect, because it requires the regulator to identify the net avoidable cost of capacity during the delivery period, including forecasting the generators’ anticipated future costs and revenues. The difficulty of detecting predatory behaviour in capacity markets may contribute to the strict regulation of bidding, including setting minimum offer prices, in US capacity markets (see description in Section 5.4, above).

A capacity market (a “quantity-based” mechanism) may present a more difficult problem for monitoring predatory behaviour. The marginal cost of capacity to a generator in a capacity auction is its net going forward costs, the difference between a generator’s estimated revenues from energy sales and its estimated costs in the period of delivery (the “missing money” owed to the generator). In principle, the same problem could affect a “price-based mechanism”, in which a predator could depress prices by investing in excess capacity.

In principle, the conditions for abuse of dominance may exist in an all-island CRM. As we noted in Section 2.1.3, ESB is the major player in the all-island wholesale market with a share of the generation of 46 per cent.\(^{108}\) ESB could “sacrifice” profits by offering to supply capacity in a CRM at a price below its average avoidable cost. This might result from ESB’s non-commercial incentives leading it to under-recover its costs (it is state-owned).

In practice, the viability of predatory strategies will depend largely on their cost, which is determined by the demand curve for capacity rather than the form of CRM (whether it is a price- or quantity-based mechanism). Vertical demand curves will tend to make predatory strategies easier to implement, because a relatively small increase in investment by the dominant firm may crash the price of capacity.

**B.3.2. An economically rational predatory pricing strategy**

In the context of a CRM, a predatory pricing strategy requires a dominant firm to deliberately depress the price of capacity to artificially low levels. In a quantity-based mechanism, this involves submitting offers to supply capacity at less than the commercially rational price, in order to induce exit by rivals. (Equally, in a price-based mechanism, making available more capacity than is commercially rational, either through new investment or delayed retirement, would have the same result). A predator charges low prices today to achieve high prices tomorrow, because rivals exit the market or potential rivals are deterred from entering the market. Alternatively, if the dominant firm is not maximising profit, e.g., a state-owned firm that aims to minimise wholesale (and hence end-user) prices, then low prices could continue indefinitely, creating a climate that is unattractive to new investment.

“Deep pockets” alone does not guarantee that predatory pricing will force rivals out of the market, which is only economically rational in the presence of imperfect financial markets (or imperfect information). In theory, the rival firms can explain to their lenders the losses they are currently suffering are a temporary phenomenon, and secure more funding in order to remain in the market. Knowing this, a dominant firm would likely not engage in predatory pricing in the first place. Imperfect information in capital markets is necessary for a successful predatory strategy. In practice, the predator’s behaviour affects a lender’s

evaluation of the smaller rival by reducing its profitability. Since the lender is not perfectly informed about the industry, and its future prospects, this places a credit constraint on small rivals that may force them to exit.\(^{109}\)

Rational firms only sacrifice profits in the short run if they believe they will secure greater profits in the long run. In the context of a CRM, this might come about for two reasons:

- **Dominance in the energy market**: offering to supply capacity at less than the net going forward cost of capacity may force rivals to exit the market. The increased market power enjoyed by the dominant firm allows it to offer to sell electricity at prices above its marginal cost. However, in the SEM the Bidding Code of Practice rules out this sort of behaviour in the energy spot market.

- **Dominance in the capacity market**: the supply curve in a capacity market will typically reflect the (low) costs of existing capacity and the (high) costs of new capacity.\(^{110}\) If a dominant firm can induce exit of rivals (or prevent entry), then it may be able to exert market power by offering to supply its existing capacity at just below net CONE. In the Great Britain capacity mechanism, this sort of behaviour is explicitly prohibited by the rule which distinguishes between “price-takers” (existing plant) and “price-makers” (new entrants).\(^{111}\) Price-takers are required to bid at no more than 50 per cent of net CONE.

\(^{109}\) See Motta, Massimo (2004), *Competition Policy – Theory and Practice*, CUP, pages 415-423. Since the cost structure of electricity generation assets is well known, it is unlikely that imperfect information about the dominant firm’s costs will allow predatory pricing to persist.

\(^{110}\) A competitive supply curve for capacity reflects the “net going forward cost” of source of capacity, which is the difference between the fixed and variable costs of operating a plant and the revenue it receives in the energy market. Existing plant which are “in merit” will typically have low or negative “net going forward costs”, since the infra-marginal rent they earn in the energy market covers their costs. Existing plant which are “out of merit”, such as peaking plant, may not cover their fixed costs, leading to a positive “going forward cost”. The most expensive point on the supply curve is the cost of constructing new plant (“Net CONE”). This last concept is that used by the RAs when determining the fixed costs of a best new entrant peaking plant—these are the “net going forward costs” of a new entrant in the SEM, as these cannot be recovered in the energy market due to the BCoP.

\(^{111}\) Great Britain CPM Impact Assessment (2013), page 58.
The practical viability of either of these strategies is constrained by both the rules placed on market participants, and the elasticity of the demand curve used to procure capacity. Rules that prevent setting price above marginal cost, and an elastic demand curve, are both likely to mitigate the risk posed by predatory pricing.

B.4. Compatibility with EU Target Model

This section discusses the compatibility of the current CRM used in the SEM with the EU Target Model, and answers the following question put to us by Viridian:

- *From an economic perspective, what changes would need to be made to the current CRM in the SEM to make it compatible with market-coupling under the EU Target model?*

The EU Target Model is a set of proposals for the design of the electricity markets in Member States, where the responsibility for any necessary redesign rests with the relevant Member States. The EU Target model itself provides a high-level outline or framework, setting out five pillars that describe how Member States’ electricity markets should operate. The five pillars are:

- Capacity calculation and zones delimitation;
- Cross-border forward hedging and harmonisation of allocation rules;
- Day-ahead market coupling;
- Intraday continuous trading; and
Cross-border balancing.\(^{112}\)

The EU Target Model neither permits (nor forbids) the introduction of a CRM. However, capacity market designs may cause conflicts with the implementation of the individual pillars. In particular, day-ahead market coupling requires the National Electricity Market Operators (NEMOs) to conduct “implicit auctions”, bundling capacity and generation between neighbouring electricity systems to allocate interconnector capacity efficiently.

The current CRM in the SEM varies every half hour, increasing in times of scarce supply (when the value of capacity is greatest), as described in Section 2.1.1 above. The payment has three elements (30% fixed, 40% variable ex ante and 30% variable ex post), one of which is not known until after the time of delivery and which varies with the loss of load probability that pertained in that hour. The RAs have stated that the current CRM in the SEM is not compatible with the day-ahead market coupling component of the EU target model:

“[The CRM] allows for capacity remuneration for all cross border flows (including capacity charges for exports) payable on a €/MWh basis. However these current arrangements would not work unaltered under the market coupling proposed as part of the EU Target Model, because the capacity price is not finally fixed until after real-time.

“To include the capacity price in market coupling would require the capacity prices to be known ex ante (for cross-border trading) which is not consistent with the calculation of an ex-ante pot that is rigidly adhered to”.\(^{113}\)

Energy traders seek to hedge the risks of movements in prices and costs when selling electricity, by agreeing a firm price for future electricity sales at the same time as agreeing the costs of that sale. In the simplest case, this is done by entering a contract to sell some volume of electricity at a later date at the same time as entering a contract to buy enough fuel to produce the volume at that date. The trader therefore removes the risk of a movement in prices or costs from its portfolio.\(^{114}\) In the current SEM, one element of the energy price (the ex post capacity payment) is not known until after delivery has been made. While traders can base their sales on the expected level of this payment, it is a risk to the level of revenue they will receive that is still outstanding after a trade is made. Moreover, this risk cannot be hedged. This feature is a barrier to trading across borders.

The RAs use the alleged incompatibility of the existing CRM with the day-ahead market coupling pillar of the Target Model as an excuse for a complete review of the CRM design. However, in practice, it need not be necessary to fundamentally redesign the CRM in order to make the mechanism compliant with the target model. One obvious minor change to the

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\(^{113}\) I-SEM – High Level Design (2014), page 97, paragraph 10.2.4.

\(^{114}\) There are, of course, many more sophisticated hedging strategies – we consider the simplest example.
existing CRM that would make it compatible with the need to have clear price discovery day-ahead would be to remove the variable \textit{ex post} element of the capacity payment and replace it with a fixed estimate of the \textit{ex post} element \textit{ex ante}. It is unlikely that this change will have significant effects on the incentives faced by the parties in the SEM to make generation available at peak, because the \textit{ex post} payment is only known after the half-hour has occurred.

An alternative approach to fixing the payments to interconnected generation \textit{ex ante} is to prevent external generators from receiving the capacity payment. The British government explicitly states that the definition of eligible generators in the GB capacity market needs to be compatible with the Target Model.\footnote{EMR Consultation (2013), \textit{Electricity Market Reform: Consultation on Proposals for Implementation}, DECC, October 2013, page 158.} Nonetheless, DECC currently plans to exclude foreign generators from the British capacity market.\footnote{EMR Consultation (2013), page 153.}

As a result, the need to comply with the EU Target Model need not require significant changes to the CRM in the SEM. Instead, complying with the EU Target Model may require adopting relatively minor tweaks to the design such as altering the \textit{ex post} component of the current CRM or adapting the rules to exclude foreign generators.
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