WHAT ROLE DOES A CAPACITY PAYMENT MECHANISM PLAY IN ENSURING ADEQUATE GENERATION IN ELECTRICITY MARKETS? AN IRISH PERSPECTIVE.

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ABSTRACT: *Capacity Payment Mechanisms are required in electricity markets to ensure security of electricity supply and to fill the so-called "missing-money" gap. Their main classification is price-based and quantity-based mechanisms. International experiences prove useful for the on-going capacity payment mechanisms review in the Irish Single Electricity Market. Regardless of the type, a convergence of some key design elements is evident. The concepts of adequacy and firmness are at the heart of the design. Optimal pricing must ensure efficient investment signals to ensure that sufficient installed capacity exists. The price must be credible and undue discrimination amongst generators is to be avoided. Capacity must be available at times of scarcity and payment for such capacity must reflect the generation unit's actual contribution to system reliability. Such issues are necessary for a properly-functioning capacity payment mechanism. The current Irish price-based mechanism exhibits certain shortcomings and its review is warranted.*

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ABBREVIATIONS

ACPS	Annual Capacity Payment Sum
BNE	Best New Entrant
BNEFC	Best New Entrant's Fixed Costs
CCGT(s)	Combined Cycle Gas Turbine(s)
CICC	CPM-Inferred Capacity Credit
CP	Capacity Payment
CPM(s)	Capacity Payment Mechanism(s)
EA	Eligible Availability
ICAP	Installed Capacity
LOLE	Loss of Load Expectancy
LOLP	Loss of Load Probability
LSEs	Load-Serving Entities
MRCP	Maximum Reserve Capacity Price
MW	Megawatt
OCGT	Open Cycle Gas Turbine
PJM	Pennsylvania, Jersey, Maryland Power Pool
RAs	Regulatory Authorities
SCCC	Study-Calculated Capacity Credit
SEM	Single Electricity Market
UCAP	Unforced Capacity
UK	United Kingdom
VOLL	Value of Lost Load
WP(s)	Work Package(s)

1. INTRODUCTION

The use of capacity payment mechanisms (CPMs) has become increasingly apparent since the advent of liberalisation, as energy-only markets are considered insufficient price-wise to attract necessary investment in generation capacity where expected revenue is unstable and investment costs may not be recovered. [1]

CPMs can be classified into two main types: price-based and quantity-based CPMs. Regardless of the approach, common design criteria is inherent which are necessary for a properly-functioning CPM. At the heart of the design are the concepts of firmness- a short to medium term issue, which concerns ready to use capacity when the system needs available generation to meet demand; and adequacy- a long term issue concerning maintaining an adequate volume of installed generation capacity to meet anticipated peak demand plus a reserve margin.[2]

Ireland is currently reviewing its price-based CPM. In particular, it is re-considering the determination of the value of the reliability product (the price), generation adequacy incentives, and the efficiency of the reliability product- "firmness". Common design criteria identified in international CPMs are useful to the Irish review. The author uses empirical analysis of selected worldwide CPMs to determine if the Irish Review is warranted and whether potential amendments are required.

The second chapter outlines the energy-only market and reason for CPMs. Chapter three examines selected aspects of worldwide CPMs to figure out some design lessons which are useful for the Irish review. Chapter four examines the current Irish CPM, aspects under review and areas where international design experience can assist. The analysis enables the author to conclude in chapter five as to whether the Irish CPM review is warranted and potential amendments justified.

2. THE 'ENERGY-ONLY MARKET' APPROACH

2.1 What is the Energy-Only Market?

An "energy-only" market is an electricity market in which there are no explicit provisions to stimulate investment in generation capacity to ensure security of electricity supply. In the spot market, the supply and demand balance determines a clearing price that determines short-run profits for capacity. In the long-run equilibrium, capacity enters to the point where anticipated short-run

[1] Wen, F.S., et al, *Generation capacity adequacy in the competitive electricity market environment*, 26 International Journal of Electrical Power and Energy Systems 365 at p. 366 (2004).
[2] Commission for Energy Regulation, Utility Regulator, Single Electricity Market, *Scope of CPM Medium Term Review, Information Paper*, AIP/SEM/09/105 at p. 10 (17 November 2009) http://www.allislandproject.org/en/cp_decision_documents.aspx?article=e8b5dd74-5be7-4dc6-a17d-20aadb247683 (last visited on December 28, 2010).

profits equate marginal capacity costs. Demand increases or supply reductions increase short-run profits in these peak periods, sending a "build" signal.[3]

To meet peak demand requirements, certain generators effectively stand in reserve to meet low-probability high-demand contingencies and must earn all of their net revenue needed to recover investment costs during these peak hours. A considerable amount of generation capacity should therefore be "in the money" to generate for such a short period. In an energy-only market, energy and ancillary prices should be sufficiently high in such hours to incentivise the necessary generation investment. If not, net revenues will not sufficiently support the efficient mix of quantity and generation capacity. The resulting underinvestment, frequent utilisation of full capacity, non-price rationing and potential network collapse is at the root of the "missing-money" problem.[4]

2.2 Shortcomings of the Energy-Only Market

Peak-periods occur all too seldom in energy-only markets making it difficult to forecast investor revenues and may encourage generators to withhold capacity to create shortages and increase electricity prices, undermining the role of price spikes.[5] Sudden peak load periods may occur, increasing electricity prices but due to long construction times of new power plants, additional capacity may not be available immediately.[6] Investment boom-bust cycles then occur where the necessary price rises may not be sufficiently indicative of shortages, and before peak prices trigger over-investment, excess capacity and lead to prices below the long- run marginal cost of generation.[7] Regulatory-set price caps, low operating reserve parameters and a lack of proper market role for real demand reduces scarcity revenue, and add to the missing-money problem.[8] Capacity payment mechanisms can make up for the missing-money gap.

3. THE CAPACITY PAYMENT MECHANISM (CPM)

CPMs can make up for the missing-money gap but in doing so effectively they must fulfil certain minimum design criteria to ensure continued generation adequacy. It is beyond the parameters of this paper to review in-depth the different types of CPMs that exist ranging from capacity payments to capacity markets. This paper focuses on the on-going review of the Irish CPM. In doing so a factual review of selected worldwide CPMs is provided focusing on those crucial design aspects that are of particular interest to the Irish CPM.

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[3] Cramton, P. and Stoft, S., *A Capacity Market that Makes Sense*, 18(7) The Electricity Journal 43 at p. 44 (2005).
[4] Joskow, P.L., *Capacity payments in imperfect electricity markets: Need and design*, 16 Utilities Policy 159 at pp. 160-161 (2008).
[5] *See* Cramton, *supra* note 3, at p. 44.
[6] *See* Wen, *supra* note 1, at p. 366.
[7] De Vries, L.J., *Generation Adequacy: Helping the market do its job*, 15 Utilities Policy 20 at p.22 (2007).
[8] *See* Joskow, *supra* note 4, at p. 170.

3.1 Classification

CPMs can be classified into price-based or quantity-based mechanisms depending on whether the main objective of the regulator is to administratively set a price for, or ensure a certain quantity of the reliability product.

3.1.1. Price-Based Mechanisms: The Capacity Payment (CP)

A CP is a centrally set price for providing capacity. The capacity price is often either fixed ex-ante in reference to the cost of a peaking unit and ignoring Value of Lost of Load (VOLL), or ex-post referring to consumers' average disutility according to the Loss of Load Probability (LOLP) estimated after the hourly/half-hourly market.[9] Its primary problems are defining the 'reliability-product' (i.e. the 'firm-capacity') and fixing the optimal price.

"Firmness" requires regulatory consideration of each existing generation unit's contribution to system reliability i.e. measurement of 'firm-capacity'.[10] Firm-capacity is usually defined based on the expected availability of each generating unit when it is most required.[11] The CP, as a financial incentive, should attract sufficient capacity to meet the desired level of generation adequacy.

3.1.1.1 United Kingdom (UK)

Until 2001, the UK market utilised ex-post calculated CPs. The price equalled the LOLP of the particular thirty-minute interval (the trading period), multiplied by the excess of the VOLL[12] over the system marginal price or the plant's bid price, depending on whether it was dispatched or not. Either way, it received payment. CPs were paid to all generation plants declared available in each thirty minute interval.[13]

The price was volatile and easy to manipulate however, for example generators withheld capacity[14] or provided inaccurate availability declarations incidentally increasing the CP prices by artificially increasing LOLP. [15]

The method of calculating the availability factor of new plants has been blamed for the high payments seen in its last years despite high capacity margins.[16] The ex-ante calculation of LOLP

[9] Finon, D. and Pignon, V., *Electricity and long-term capacity adequacy: The quest for a regulatory mechanism compatible with electricity market,* 16 Utilities Policy 143 at p.151 (2008).
[10] Batlle, C. and Pérez- Arriaga, I.J., *Design criteria for implementing a capacity mechanism in deregulated electricity markets*, 16 Utilities Policy 184 at p.186 (2008).
[11] Batlle, C. and Rodilla, P., *A critical assessment of the different approaches aimed to secure electricity generation supply*, 38 Energy Policy 7169 at p.7172 (2010).
[12] The regulator administratively determined VOLL by estimating the annual marginal cost of capacity required to meet expected demand at the required reliability standard.
[13] *See* Batlle, *supra* note 11, at p. 7172.
[14] *See* Wen, *supra* note 1, at p. 370.
[15] Roques, F.A., *Market design for generation adequacy: Healing causes rather than symptoms*, 16 Utilities Policy 171 at p.177 (2008) referring to Green, R., *Did English Generators Play Cournot? Capacity With-holding in the Electricity Pool*, CMI Working Paper 41, (March 2004) http://www.eprg.group.cam.ac.uk/wp-content/uploads/2008/11/ep41.pdf (last visited on December 28, 2010).

(by computer programme) was not transparent and the probabilities of 'disappearance' of each generating unit systematically underestimated the actual capacity available and dispatched during peak periods, facilitating gaming.[17] Average availability used in calculations ignored what plants were fully or less available at peak or off-peak times, respectively. Furthermore, it is difficult to measure the value customers put on security of electricity supply and it has been argued, based on price elasticities that the VOLL was also underestimated.[18]

This mechanism illustrates the difficulty in calculating an optimal price on the basis of VOLL and LOLP as well as the inaccuracy of using "average" availability to ensure generation in times of scarcity. It became redundant once the New Electricity Trading Arrangements entered the UK in 2001.

3.1.1.2 Spain

Spain's former "capacity guarantee mechanism" awarded each (available) generating unit a daily payment which was calculated by multiplying each unit's firm-capacity, based on an average availability rate,[19] by a regulator-determined per unit capacity payment that could vary by season. There was no real reliability-product provided by the generator, however as if the generator was unavailable when demand exceeded supply, it lost only the value of its CP for that day and thus had no real incentive to ensure reliability of capacity product. The generator had no incentive to be available and producing at times of most scarcity and generators often declared availability but submitted high bids to ensure they were excluded from dispatch in the energy market to avoid losing capacity payments (which would be lost were they included in dispatch but unavailable when called on).[20] The regulator's power to modify the mechanism at any time also undermined the effectiveness of the long-term investment signal.[21]

The re-designed Spanish mechanism consists of an availability incentive, allowing the System Operator (SO) to enter bilateral contracts with peak plants of maximum one year duration and an investment incentive for units over 50MW, plus an annual capacity payment per installed MW of generation in their first ten years of operation. This ten-year payment is mainly aimed at Combined Cycle Gas Turbines (CCGTs) entering the market post-1998. The SO's calculation of a 'reserve margin index' also influences the investment incentive.[22]

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[16] *Ibid,* at p. 177
[17] *See* Roques, *supra* note 15, at p.177.
[18] Roques, F.A., et al, *Investment Incentives and Electricity Market Design: the British Experience*, 4Review of Network Economics, 2, at p.102 (2005) http://www.tilburguniversity.edu/research/institutes-and-research-groups/tilec/events/conferences/03112005/reading.html/roques.pdf (last visited on December 28, 2010).
[19] An average availability rate was multiplied by a capacity value which schematically equalled thermal units' installed capacity or hydro plants' average year's production of energy.
[20] *See* Roques, *supra* note 15, at p.178.
[21] Batlle, C., et al, *Enhancing power supply adequacy in Spain: Migrating from capacity payments to reliability options*, 35 Energy Policy 4545 at p.4548 (2007).
[22] *See* Batlle, *supra* note 11, at p.7173.

The re-design deals with many of the old problems. The availability incentive ensures (by contract) that peak plants commit available capacity (the reliability-product) annually, which then ensures that capacity is available particularly at times of scarcity. The investment incentive ensures that newer efficient conventional generators continue to provide capacity in times when increasing renewable electricity generation is entering markets levelling the playing field to an extent. The long-term nature of the mechanism also reduces regulatory uncertainty.

3.1.2 The Quantity-Based Mechanism

Unlike price-based mechanisms, quantity based mechanisms ensure an adequate quantity of capacity, as the quantity required to ensure adequate generation is declared by the regulators and the price is revealed by the market-based mechanism. [23]

3.1.2.1 The PJM

Installed Capacity (ICAP) markets were in use in the Eastern USA until recently. In the Pennsylvania, Jersey, and Maryland Power Pool (PJM), load-serving entities (LSEs) were obliged to purchase enough capacity credits (the reliability-product) from generating companies to cover their peak demand. So, the entire system had sufficient generating capacity to meet system peak demand plus an administratively determined reserve margin. Initially, all generation units received credit for all of their ICAP.[24] Realising that capacity is not always available (a firmness problem) and that in terms of adequacy the agreements were considered too short to incentivise new investments, the Unforced Capacity (UCAP) model was subsequently adopted. Under the UCAP, the ISO discounted the amount of the product the generator was entitled to sell based on its historical availability over long time periods. However, the incentive to be available during tight reserve periods and in every other hour that existed under the ICAP, continued in the newer UCAP model. The addition of a 'must-offer' requirement in the day-ahead market did not solve this problem as generators self-reported availability and hid their unavailability by bidding high prices.[25]

This design illustrates that crediting generators for all of their installed capacity is not useful, as such capacity is not always available. Discounting capacity credits using historical availability will not ensure availability at times of scarcity. There should be adequate incentives to be available during hours of highest scarcity, which incentives should relate to actual and not historical or theoretical performance.[26]

In the old PJM design, extremely volatile prices also existed depending on the size of the reserve margin caused primarily by capacity demand inelasticity. In times of tight reserves, scarcity prices

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[23] *Ibid*,at p. 7173
[24] *See* De Vries, *supra* note 7, at p.26.
[25] *See* Batlle, *supra* note 11, at p.7174.
[26] *See* Joskow, *supra* note 4, at p.169.

were high but capacity remuneration was uncertain and incapable of certifying recovery of fixed investment costs. The short period in calling capacity auctions meant that only existing generating units could participate in the auction and thus, couldn't internalise their investment costs in their bids resulting in near-zero prices during long periods as the cost of keeping existing ICAP operational (which was what had to be bid), was near zero.[27] This experience illustrates the importance of price stability and adequacy. Investors will be reluctant to invest if prices are volatile and not guaranteed to cover their investment costs.

The short notice for committing capacity has the effect of excluding potential competitors, limiting new capacity, allowing incumbents to exercise market power and lowering capacity prices undermining the investment signal for long-term generation adequacy. These problems have been tackled in the PJM's new reliability pricing model- an auction for a reliability product based on an evolution of the UCAP. It now measures availability more precisely based on a unit's actual contribution to overall system reliability.[28] Furthermore, new mechanisms include penalties for capacity not being available when most needed.[29] The new PJM model also adopts longer "lag periods"[30] allowing new entrants time to build capacity, as well as longer commitment durations, enhancing investor confidence and easing project finance.[31]

3.1.2.2 New England

The New England ICAP mechanism has been replaced by the forward capacity market. The ISO pays suppliers to ensure adequate capacity is available to meet future peak loads. 100% of the region's installed capacity is procured for the capacity delivery period, beginning three years later. Descending-clock auctions establish the capacity price. New capacity can set the market clearing price and only those bidding under the market clearing price commit capacity and get paid for delivery. Existing resources at auction time obtain a one-year commitment to provide capacity being paid monthly at the clearing price of the auction associated with the delivery period. New resources that are cleared elect delivery periods of 1-5 years as part of their bid and receive the guaranteed price for that period, locking it in regardless of subsequent auction clearing prices.[32]

Apparent here is another important design element- investors considering entering the market should have some option of locking capacity prices for some time ahead of completion.[33] This ensures adequacy, providing certainty for investors in recouping investment costs and mitigates boom-bust cycles. Allowing new capacity to set the price ensures cost recovery whereas

[27] *See* Batlle, *supra* note 11, at p.7174.
[28] *See ibid*., at p.7176.
[29] *See* Joskow , *supra* note 4, at p.169.
[30] I.e. the time interval between the signing of the committal to delivery and the moment it must be delivered.
[31] *See* Batlle, *supra* note 11, at pp. 7174-5.
[32] Jenkins, C., et al, *Energy efficiency as a resource in the ISO New England forward capacity market*, at pp.177-8 (2009) http://www.veic.org/Libraries/Resource_Library_Documents/ISO_NewENgland_ECEEE_Jenkins.sflb.ashx (last visited on December 28, 2010).
[33] *See* Joskow , *supra* note 4, at p.169.

electing delivery periods guarantees set prices. The design is useful for showing how certainty can be provided to existing generators also.

3.1.2.3 Columbia

The current Columbian mechanism features reliability- option acquired via centralised descending-clock auctions. The option is essentially a call-option contract with a calculated strike price[34] that indicates scarcity periods. Generators receive payment for providing firm-energy (the reliability product). When the spot price exceeds the defined scarcity price, all generating units selling the option must sell the committed energy at the strike, not spot market price. New and existing plants have different rules in auctions, e.g. existing plants are price-takers limiting market power abuse. Auction prices can be locked-in from four-to-seven years ahead related to plant lead times. [35] New resources can specify a commitment period of 1-20 years locking in the price, which is adjusted by inflation. Existing resources have a commitment period of one year as their fixed costs are already sunk.

This design demonstrates how new and existing generation can be differentiated. Long notice of a long-term contract with a locked price for new generation incentivises build. A fixed commitment period with a locked price also incentivises continued generating capacity by existing generators. Long notice of the commitment period allows for efficient investment and eases project finance.

3.1.2.4 Western Australia

The Western Australian Reserve Capacity Mechanism obliges all suppliers to bilaterally contract capacity credits covering their share of future system capacity requirements.[36] The components of the Maximum Reserve Capacity Price (MRCP) that sets the cap (for bids) for the auction-process are reviewed annually. The price is based on an Open Cycle Gas Turbine (OCGT) plant.[37] The estimation of costs incurred in a power station's development includes a margin to cover contingencies- provisionally set as 18.6% for 2011. It is added as a fixed percentage of the power station development's capacity costs.[38]

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[34] Related to a high priced generator's marginal costs.
[35] *See* Batlle, *supra* note 11, at pp.7175-6.
[36] *Ibid*, at pp.7175-7176
[37] IMO Western Australia, *Market Procedure for: Determination of the Maximum Reserve Capacity Price*, Vol. 2., at pp. 1-2, (undated) http://www.imowa.com.au/f711,828707/Market_Procedure_for_Maximum_Reserve_Capacity_Price.pdf (last visited on December 28, 2010).
[38] IMO Western Australia, *Draft Report: Maximum Reserve Capacity Price Review for the 2013/14 Reserve Capacity Year*, at p.11 (November 2010) http://www.imowa.com.au/f175,856424/IMO_Draft_Report_Max_Reserve_Capacity_Price_2013_14.pdf (last visited on December 28, 2010).

This CPM illustrates the use of cost of new entry (usually peaker plants) in price formation be it in a capacity payment or auction - a cost used by most CPMs. This margin for contingencies is a beneficial aspect and is useful for covering off volatile or unexpected cost changes.

3.2 Common Design Elements

These CPMs illustrate some key design elements that are central to a well-functioning CPM. Price calculation on the basis of VOLL or LOLP is notoriously difficult and the cost of new entry can be calculated to include contingencies. In terms of firmness- the reliability product- a calculation involving average availability will not ensure availability at critical times. Generators should be incentivised to generate at such times based on actual availability and thus real contribution to system reliability. Regarding adequacy, incentives must ensure that not only new, but existing, generators continue to generate capacity. Longer notice or lag periods before the commitment period, pre-locking capacity prices and longer commitment durations all add to the incentive to generate and commit capacity, ensuring adequate generation. How these criteria fit in the Irish mechanism and its on-going review is what the author now turns to.

4. THE IRISH APPROACH

4.1 The Irish SEM and the CPM Objectives

The Irish all-island Single Electricity Market (SEM) is a day-ahead gross mandatory pool with a single clearing price and an explicit capacity payment mechanism. Daily trading periods last thirty-minutes. Generators' two major revenue streams are trading (mostly energy) payments and capacity payments. The latter is awarded to generators on the basis of their availability, whether or not they are dispatched.

The CPM is a price-based mechanism and its overarching objectives are: [39]

1. Ensuring capacity adequacy or reliability of the system;
2. Price stability;
3. Simplicity;
4. Efficient price signals for long term investments;
5. Inhibit susceptibility to gaming; and
6. Fairness.

[39] Commission for Energy Regulation, Utility Regulator, *Capacity Payment Mechanism and Reserve Charging High Level Decision Paper*, AIP/SEM/53/05 at pp.5-6 (15 July 2005) http://www.allislandproject.org/en/capacity-payments-decision.aspx?article=aa084bc6-3d33-4c7f-91a4-903a34011106 (last visited on December 28, 2010).

4.2 The CPM Medium Term Review

The SEM Committee has recently embarked on a CPM Medium Term Review for the purposes of examining if the current design can be further improved to optimally meet the CPM objectives. The review is to occur in two phases: a Historical Phase and a CPM Enhancement Phase, each with five "Work Packages" (WPs). This paper focuses on selected aspects of the CPM Enhancement Phase which phases focus on such concerns as the treatment of technologies in the CPM, particularly wind (WP6). Re-consideration of the calculation of the fixed "pot" at the heart of the mechanism is the only WP produced to date (WP7). Concerns over generator incentives and timing and distribution of payments are also under consideration (WP8-9).

4.3 The Current CPM

An explanation of the current operation of the CPM, the related areas of the Review and the author's views thereon, in light of international CPMs and the Irish CPM objectives (CPM objectives) now follows.

4.3.1 The 'Pot'/Annual Capacity Payment Sum

The CPM is a Fixed Revenue division mechanism whereby a formula establishes a set amount of revenue to be paid out in administrative capacity payments among all participants throughout the year. At its core is a fixed 'pot' of money- the Annual Capacity Payment Sum (ACPS) - calculated at the start of each year by the Regulatory Authorities (RAs) and the SOs, as the multiple of a volume element (which is the generation capacity in megawatts required to adequately serve market demand) and a price element in €/ kilowatt- the annualized fixed costs of a BNE peaking plant (BNEFC). The pot ensures that BNE peak plants are paid at a profitable rate. It is funded by levying capacity charges on supplier units according to their electricity consumption and is published four months prior to the commencement of the Trading Year. There is thus no lag period and a commitment period of just one year.

4.3.1.1 The CPM Review and BNE Fixed Costs

Concerns by industry players regarding the stability of the 'pot' due to annual determination of BNEFC and the ACPS, led to re-consideration of the BNEFC calculation.[40] The current methodology for assessing peaking capacity costs estimates the full project costs incurred in developing a new BNE peaking plant, taking into account anticipated infra-marginal rents which are

[40] Commission for Energy Regulation, Utility Regulator, *Fixed Cost of a Best New Entrant Peaking Plant, Capacity Requirement, and Annual Capacity Payment Sum for Calendar Year 2009*, *Decision Paper*, AIP/SEM /08/109 at p.38 (11 September 2008) http://www.allislandproject.org/en/cp_decision_documents.aspx?page=2&article=5da42fd7-b27f-48a2-818d-27f9a9fee186 (last visited on December 28, 2010).

realised from the energy and ancillary services markets.[41] WP7 articulates four alternative options for replacing this method.

4.3.1.1.1 An Original Option[42]

One option considered as a replacement of the BNEFC calculation, was an option which was previously considered prior to SEM's establishment in 2007. The peaking plant's marginal cost of incremental capacity would be assessed on the basis of VOLL, LOLP, a comparison of the adequacy level to a standard[43]and the Forced Outage Probability.

The UK used a similar method. One of the main reasons for rejecting this option originally was the difficulty in determining VOLL and LOLP.[44] These fears are considered lessened due to the experience of the SEM. Furthermore, the Irish calculation would be annual (not half-hourly as in the UK). According to WP7, it would have insignificant changes in the current method of calculating the capacity pot as the required inputs are already consulted and considered annually (VOLL being adjusted annually by various indices). The resulting values compare favourably with the current method; it can reduce volatility and is simple to calculate.[45]

Taking into account the reason for the BNEFC review and the CPM objectives, one must question whether an annual calculation using an alternative method such as the above, is the best alternative. The uncertainty an "annual" determination carries with it remains. Though an annual determination might reduce susceptibility to gaming, its "simplicity" is questionable- the dangers of miscalculating VOLL due to price elasticities and the differences of VOLL between consumer categories still remain. VOLL estimates could however be derived from the willingness of consumers to reduce load at times of scarcity,[46] simplifying this aspect in line with stipulated CPM objectives.

4.3.1.1.2 Steady Component Costs

The next option considered utilises the current method but with some component costs being fixed for three or five years (using indexing for intervening years). The constant elements might include

[41] Commission for Energy Regulation, Utility Regulator *Single Electricity Market, Fixed Cost of a New Entrant Peaking Plant for the Capacity Payment Mechanism, Decision and Further consultation Paper*, AIP/SEM/07/14 at p.14 (13 February 2007) http://www.allislandproject.org/en/capacity-payments-consultation.aspx?article=3a72c290-e714-42ee-97b3-4c8ff691f42e (last visited on December 28, 2010).

[42] Commission for Energy Regulation, Utility Regulator *CPM Medium Term Review- Work Package 7- BNE Calculation Methodology*, AIP/SEM/10/068 at p.13 (7 October 2010) http://www.allislandproject.org/en/project_office_sem_publications.aspx?year=2010&section=2 (last visited on December 28, 2010).

[43] Currently 8 hours/ year, in order to assess the system's adequacy.

[44] Commission for Energy Regulation, Utility Regulator, Single Electricity Market *Fixed Cost of a New Entrant Peaking Plant for the Capacity Payment Mechanism, Consultation Paper*, AIP/SEM/124/06 at pp.10-11 (15 September 2006) http://www.allislandproject.org/en/capacity-payments-consultation.aspx?article=3a72c290-e714-42ee-97b3-4c8ff691f42e (last visited on December 28, 2010).

[45] *See* Commission for Energy Regulation, *supra* note 42, at pp.14-15.

[46] *See* Roques, *supra* note 18, at pp.102-3.

choice variables (e.g. peaker technology, plant capacity) and cost/revenue variables. The constant period might vary depending on the element's price stability. A commitment period longer than one year is suggested though this might not reflect market changes as accurately. WP7 acknowledged that the fewer the re-assessed variables, the steadier the cost but such re-assessments enhance the CPM's perceived volatility.[47]

The author agrees with the constant component suggestion. Varying the constant period for elements may however undermine the simplicity objective. Keeping all chosen variable elements constant for the same period with indexation to mitigate changes, would be preferable and provide enhanced price certainty. A margin for contingencies as used in Western Australia would also be useful. Such price stability coupled with a commitment period beyond one year is in line with CPM objectives, underscores investor confidence and eases project finance as seen in the new PJM mechanism. Another possible addition is an increased lag period before the commitment period starts which would also comply with CPM objectives.

4.3.1.1.3 Fixing the BNEFC for Multiple Years

This option recommends calculating the BNEFC as currently done and keeping it in place for a multiple year period with appropriate indexation. In the medium term this would increase project revenue certainty and reduce volatility. Possible step changes between calculation periods may occur though some elements could be reviewed more frequently than the cycle years to minimise such potential step changes.[48]

This option is quite similar to the previous option. Appropriate indexing would mitigate market change reflection concerns. As regards the step changes, the author reiterates the previous option's points to varying elements and a margin of headroom. In line with CPM objectives, a fixed BNEFC for multiple years with indexation and headroom stabilises the price, simplifies the process and enables efficient decisions for long-term investments.

4.3.1.1.4 Fixed Price for New Entrants

The final option fixes a price for new entrants by:

a. Guaranteeing at commissioning, the BNE price for all new entrants adjusted by capacity credits with the residual pot being allocated among existing generators;
b. Guaranteeing only new conventional generators a BNE price for some years with renewable and existing generators being allocated the residual pot (on the rationale that renewables are already incentivised by external market mechanisms).

[47] *See* Commission for Energy Regulation, *supra* note 42, at p.17.
[48] *See ibid*, at p.22.

WP7 believes this method would reduce capital costs and help deliver new capacity when needed. Existing generators' payments level may be uncertain possibly leading to demands for a bigger ACPS pot or grandfathered minimum payments. Contrary to the fairness objective, there is potential discrimination against existing older generators. Additional issues surrounding this option include the amount and length of the guarantee, whether to adjust it for reliability or link it to a capacity requirement to prevent over-investment and reduced payments on exhaustion of the guarantee.[49]

The Spanish investment demonstrates how to attract new (and existing where considerable capacity upgrades occur) conventional generators by receiving an additional payment for ten years. The New England and Columbian mechanisms distinguished new and existing generators. New resources can lock-into a fixed price adjusted by inflation for a long length of time and existing generators can do so but for a lesser period. Fixed prices are a positive investment incentive.

Regarding option "a", there is no explicit incentive for existing generators. This could be mitigated by providing a Spanish-type payment for a set period for existing conventional generators only, as renewables are externally incentivised by feed-in-tariffs in line with price stability and system reliability objectives. Alternatively, the residual pot could be split among all existing generators and adjusted by their capacity credits to ensure fairness and contribution to system reliability. Regarding option "b", existing conventional and all renewable generators are lacking price incentives. On the basis that renewables are externally incentivised, a fixed payment for existing conventional generators for a length of time shorter than that for new conventional generators might be considered. This raises compatibility issues with the fairness objective however and an alternative might be the allocation of the residual pot amongst all renewable and existing conventional generators adjusted by capacity credits. The latter option reflects fairness, system reliability and simplicity.

A fixed-price incentivises investment, underscores adequacy and is in line with the objective of efficient price signals. Whichever guarantee might proceed (if any), it must be adjusted by inflation and consideration of incentives for those generators outside the fixed-price guarantee should be considered in line with the above options.

4.3.1.2 Timing and Division of the Pot

The pot is divided into 12 Capacity Period Payment Sums which must be paid monthly. A high unit price is ensured at times when capacity is most needed, determined by weighting requirements

[49] *See* Commission for Energy Regulation, *supra* note 42, at p.23.

based on forecast demand. Scaled weighting creates an appropriate differential to deal with summer/winter demand differentials.[50] Twelve monthly payments ensure a stable revenue stream for generators even if one loses one month's payment for being unavailable for a month (e.g. out on maintenance). The monthly payment for availability is broken into three sums:

- Capacity Period Fixed Sum: 30% of pot[51]
- Capacity Period Variable Sum: 40% of pot[52]
- Capacity Period Ex-post Sum: 30% of pot.[53]

The fixed and variable sums provide stable revenues while the ex-post sum reflects price-volatility. The pot is paid out on the basis of Eligible Availability (EA) in each thirty-minute trading period regardless of the technology type or characteristics such as start-up times, tripping likelihoods or ramping rates. Wind generators' EA is its capability to generate given the prevailing wind conditions and is calculated as the MW hours generated in each thirty-minute, and converted to a MW availability figure, regardless of whether it is constrained down or not. Conventional generators on the other hand are paid for all of its installed capacity as conventional fuel allows generation at full capacity during the day and it is continuously available to generate.[54] Thus generation units' real contribution to system reliability and security of supply when most needed is not actually assessed.

This monthly division of the pot, the three different payment streams and the EA basis of paying the pot have given rise to further WPs in the CPM Enhancement Phase.

4.3.1.2.1 The CPM Review- Generation Technologies, Incentives and Distribution of Capacity Payments

Work Packages 6, 8 and 9 have not yet been published for consultation but recent CPM-related discussion papers have highlighted the main concerns arising.

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[50] Commission for Energy Regulation, Utility Regulator, *The CPM and Associated Input Parameters*, AIP/SEM/09/06 at p. 22 (26 July 2006) http://www.allislandproject.org/en/capacity-payments-decision.aspx?article=cb31a431-857d-46af-957e-d6b08ca30703 (last visited on December 28, 2010).

[51] Valuing the required availability in trading periods before the start of the year.

[52] A time-of-day signal valuing required availability more during low than high margin periods before the start of the capacity period.

[53] Profiled into trading periods ex-post, reflecting availability on the basis of system conditions at the time.

[54] Commission for Energy Regulation, Utility Regulator, *Preliminary Analysis of the Treatment of Different Technology Types under the Capacity Payment Mechanism in the SEM,* AIP/SEM/08/177 at p.16 (17 December 2008) http://www.allislandproject.org/en/project_office_sem_publications.aspx?year=2008&section=2 (last visited on December 28, 2010).

4.3.1.2.1.1 The Concerns

The Review recognises the importance of equitably rewarding generation capacity which should reflect its contribution to generation adequacy in the long term and availability to meet demands at low margins. Capacity credits and discrimination among technologies may have roles to play. [55]

The Eligible Availability criteria for making payments has been called into question, raising the issue of the proper definition of the reliability product whose main components are noted as adequacy and firmness. Reward for contributing to capacity security, and charges for not providing committed firmness when required or dispatched are noted.[56]

Finally, it is observed that the three payment streams do not sufficiently reflect different capacity values throughout the day/week/season especially as the ex-post stream (30% of each monthly pot), is the only one that uses actual LOLP. The accuracy of the 12 monthly pot split in sending appropriate signals for plant availability is questioned. For example, the summer period's monthly pot is smaller but plant maintenance often occurs at this time and may increase capacity requirements. The monthly calculations however ignore the LOLP in each month profiling over a smooth load-following shape.[57]

4.3.1.2.1.2 Grounds for Concern

The background to these concerns arise from an analysis of all SEM technology units participating in the CPM wherein two methods of hypothetically calculating a capacity credit were used- defining a capacity credit as the contribution of a single 100% available megawatt of generation to security of supply.[58] The Study-Calculated Capacity Credit (SCCC) method measures the security of supply standard of an electrical system, first with all generation types, then without the wind-element and subsequently, re-calculates the amount of perfectly available generation needed to achieve the original standard, which amount is the measure of the wind generation's capacity credit.[59] The CPM-Inferred Capacity Credit (CICC) method is calculated by comparing the actual revenues that have been earned by different technologies under the current CPM per €/installed MW/hour capacity, against hypothetical revenues earned by a perfectly available MW of generation.[60]

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[55]Commission for Energy Regulation, Utility Regulator, *Information Paper on Scope of Medium Term Review*, AIP/SEM/09/105 at p. 17 (17 November 2009) http://www.allislandproject.org/en/project_office_sem_publications.aspx?year=2009&section=2 (last visited on December 28,.2010).

[56] *See ibid*., at p.10.

[57] *See* Commission for Energy Regulation, *supra* note 54, at p.12.

[58] *See* Commission for Energy Regulation, *supra* note 53, at p.17. Caveats noted which may also cause some differences between the two methods include the diversity of wind time series in the study and that calculations are only based on 8 months of SEM experience.

[59] *See ibid.*

[60] *See ibid*., at p.20.

A comparison of the two methods showed that wind generation is being paid approximately 44% more than its "true" SCCC. It was also noted that the current CPM's fixed and variable payment streams reward wind generation based on average behaviour. Days with high-load and low-wind now contribute most to Loss of Load Expectancy (LOLE), as opposed to just high-load days. The SCCC captured the relationship between high-load and wind generation and found that increasing installed MW of wind generation reduces the LOLE on windy high-load days but its marginal capacity value[61] decreases once it achieves reduced LOLE on windy days. Additional non-diverse wind capacity does not enhance security of supply during high-load low-wind days.[62]

Current capacity payments do not reduce pro-rata as wind levels increase. Over-remunerating wind generation under-remunerates conventional plants, though both compete for the same pot.[63] The current ex-post stream does however capture actual half-hourly load and wind generation. A hypothetical CICC calculated payment under a 100% ex-post stream demonstrated that the stream recognises that wind is not contributing to those days and hours when most generation availability is required, so giving more weight (than 30%) to the ex-post stream could reduce overpayments.
Full payment of the CPM pot under a 100% ex-post sum does not capture the full reduction of the marginal benefit of wind however. The twelve monthly payments design aspect would ensure that a generator still obtains considerable payments in eleven months in the case where all of the year's high-load, low-wind days occur in a single month when little would be earned under the ex-post stream in that month only. An alternative is to calculate the capacity credit over the entire year with each high-load low-wind day contributing to a single LOLE calculation for the year, reflecting wind-generators' unavailability during the most important days of the entire year. [64]

4.3.1.2.1.3 The Reality

With an increasing amount of wind power generation coming into the SEM, wind cannot be overpaid to the detriment of conventional generation which is crucial not least in terms of its role for backing-up wind generation.

The definition of the reliability product- firmness- is at the crux of the matter. What is the wind or conventional generator providing in return for the capacity payment? Availability needs to be measured based on a unit's actual availability and thus real contribution to overall system reliability. As the international mechanisms reviewed earlier showed, payment must be given in

[61] Its true contribution to reducing loss of load.
[62] *See* Commission for Energy Regulation, *supra* note 53, at pp.26-7.
[63] Commission for Energy Regulation, Utility Regulator, *Wind Generation in the SEM*, AIP/SEM/08/002 at pp.24-25(11 February 2008) http://www.allislandproject.org/en/project_office_sem_publications.aspx?year=2008&section=2 (last visited on December 28, 2010).
[64] *See* Commission for Energy Regulation, *supra* note 53, at p.27. This is the SCCC method.

return for not only available capacity but availability at critical times. Calculations based on Eligible (effectively average) Availability as is occurring for wind in Ireland will not guarantee such availability. Neither will crediting Irish conventional generators for all of their installed capacity as similarly occurred in the old PJM mechanism. Average availability does not reflect what plants are fully nor less available at peak or off-peak times as witnessed in the old UK and Spanish mechanisms, and no real product is being provided by the generator if it merely loses its payment on the day, or month in the Irish CPM as it is not available when required. Adequate incentives should exist to encourage availability during hours of most scarcity which is dealt with in the new PJM mechanism by measuring availability based on a unit's actual contribution to overall system reliability. Penalties can be imposed for non-availability. Another option to ensure peak capacity is the new Spanish CPM's method of contracting peak plants.

The capacity credit studies undertaken in the Irish CPM convincingly show that wind is being overpaid. When the marginal capacity value of wind begins decreasing, capacity payments must reflect this. The ex-post stream is currently the only stream that recognises actual, as opposed to average load and wind generation, and thus its actual contribution to system reliability. It has been hypothetically proven that an increased percentage of payments under the ex-post stream would reduce overpayments reflecting actual contribution to system reliability and ability to meet critical period demand. This complies with CPM objectives of system reliability, fairness and efficient price signals for investment. The twelve monthly pot design element however inhibits accurate reflection of availability under a 100% ex-post sum for the sake of twelve stable revenue streams for generators. The alternative single annual calculation of LOLE which more accurately reflects overall reduction in capacity value is favoured. This alternative together with subjecting all technologies to a "true" SCCC capacity credit measurement as well as increasing the percentage of payments under the ex-post stream should help reduce overpayments to wind, provide more payments for conventional generators and enhance availability at critical periods while complying with CPMs objectives of system reliability, efficient price signals for investment and fairness.

5. CONCLUSION

A certain convergence of design criteria can be identified from international CPMs- be they price based or quantity based- which can be applied to the Irish CPM. Crucial design aspects include adequacy and firmness.

In terms of adequacy to ensure sufficient available generation capacity, incentives must be appropriate. The credibility of the mechanism is important for enabling investment incentives to operate effectively. Optimally, pricing the reliability product is notoriously difficult and frequent potential regulatory interference may deter investment. Price stability beyond a period of one year is a positive investment incentive, underscores investor confidence and eases project finance. Price incentives must not however unduly discriminate between new and existing generators or technologies if adequacy is to be maintained.

In terms of firmness, capacity must be available and available when most needed. The timing and distribution of the Irish capacity payment pot is inappropriate. Wind is over-remunerated. CPMs must reflect a unit's actual contribution to system reliability at critical times. The Irish CPM design inhibits this reflection. An alternative is required. Measuring each generation technology's "true" contribution to system reliability by capacity credits can mitigate the situation. Overpayments to wind must be reduced to counter under-payments to conventional generators. Availability at critical periods must be ensured. All potential amendments must be in compliance with the overarching CPM objectives. Therefore, the Irish CPM review is warranted.

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