



Title	Investment vs. Refurbishment: Examining Capacity Payment Mechanisms Using Stochastic Mixed Complementarity Problems
Authors(s)	Lynch, Muireann Á., Devine, Mel T.
Publication date	2017-04-01
Publication information	Lynch, Muireann Á., and Mel T. Devine. "Investment vs. Refurbishment: Examining Capacity Payment Mechanisms Using Stochastic Mixed Complementarity Problems." International Association for Energy Economics (IAEE), April 1, 2017. https://doi.org/10.5547/01956574.38.2.mlyn .
Publisher	International Association for Energy Economics (IAEE)
Item record/more information	http://hdl.handle.net/10197/11049
Publisher's version (DOI)	10.5547/01956574.38.2.mlyn

Downloaded 2026-05-02 00:30:33

The UCD community has made this article openly available. Please share how this access benefits you. Your story matters! (@ucd_oa)



© Some rights reserved. For more information

Investment vs refurbishment: examining capacity payment mechanisms using stochastic mixed complementarity problems

Muireann Á. Lynch^{*1} and Mel T. Devine^{2,1}

¹Economic and Social Research Institute, Dublin, Ireland / Department of Economics,
Trinity College, Dublin, Ireland

²Mathematics Applications Consortium for Science and Industry (MACSI), Department
of Mathematics and Statistics, University of Limerick, Ireland

February 8, 2016

Abstract

Capacity remuneration mechanisms exist in many electricity markets. Capacity mechanism designs do not explicitly consider the effects of refurbishment of existing generation units in order to increase their reliability. This paper presents a stochastic mixed complementarity problem to examine the impact of refurbishment on electricity prices and generation investment. Capacity payments are found to increase reliability when refurbishment is not possible, while capacity payments and reliability options yield similar results when refurbishment is possible. Final costs to consumers are similar under the two mechanisms with the exception of the initial case of overcapacity.

Keywords: Capacity markets; Reliability; Mixed complementarity problem; Stochastic modelling

*Corresponding author: muireann.lynch@esri.ie

Nomenclature

$\gamma_{p,s}$	(Lagrange) variable giving the energy price in period p and scenario s
$B_{f,t,s}$	Binary parameter indicating whether a unit of technology t owned by firm f is available in scenario s
$CAP_{f,t}$	Parameter giving the initial capacity of technology t held by firm f
cp	(Lagrange) variable giving the capacity price per MW
E	Slope of the demand curve
$exit_{f,t}$	Variable giving the exit decisions made by firm f for technology t
F	Total number of firms
f	Generation firms
$gen_{f,t,p,s}^{new}$	Variable giving the generation from new capacity of technology t owned by firm f in demand period p for scenario s
$gen_{f,t,p,s}$	Variable giving the generation from existing capacity of technology t owned by firm f in demand period p for scenario s
$ICOST_t$	Parameter giving the investment cost of technology t
$inv_{f,t}$	Variable giving investment by firm f in technology t
MC_t	Parameter giving the marginal cost of technology t
$MCOST_t$	Parameter giving the maintenance cost of technology t
p	Demand period
pr_s	Probability of scenario s
$R_{f,t}$	Parameter giving the initial reliability of each technology owned by each firm
$RCOST_t$	Parameter giving the refurbishment cost of technology t
$refurb_{f,t}$	Variable giving the refurbishment decisions of each firm for each technology
s	Scenarios
T	Total number of technologies

t	Generation technologies
Z_p	Intercept of the demand curve at period p

1 Introduction

Electricity markets worldwide have undergone a process of liberalisation in recent decades. Electricity generation, which was the preserve of state-owned vertically integrated utilities, is now a competitive industry. However, electricity market structures differ from one country to the next. One of the significant differences that can arise between markets is whether they have a specific capacity remuneration mechanism (CRM), and if so, the form it takes.

A CRM aims to compensate generation firms for owning generation capacity, regardless of the extent to which it is utilised. An electricity market which includes a CRM is usually considered as the alternative to an ‘energy-only’ market, in which generators are compensated on the basis of the energy they generate only. Electricity cannot be easily or economically stored, and blackouts or brownouts are not socially or politically acceptable. There is thus a requirement for sufficient generation capacity to meet demand at all hours of the year, including peak demand hours, and so some peaking units are required which cannot expect to generate for more than a few hours per year. Ensuring sufficient revenue to render such units economically viable is the main reason for CRMs.

There are several arguments put forward as to why such low-load units would not prove viable in the absence of a CRM. The first is the absence of an active demand-side in electricity generation markets, which means that consumers cannot signal their desired level of reliability of supply (Cramton and Stoft, 2005). There is therefore a weaker price signal for reliable supply, and consequently for electricity generation capacity. There is also an opportunity and incentive to exercise market power, particularly in the period close to real time. Another argument in favour of CRMs is the the shared nature of the electricity network. This introduces a ‘free-rider’ problem, whereby it is not possible to differentiate between consumers who had entered into a contract for reliable supply. The imposition of price caps in electricity markets, often for political reasons, is also argued to reduce investment incentives for low-load units (Grigorjeva, 2015). Finally it can be argued that electricity has public good characteristics (Abbott, 2001), and so policy-makers may be reluctant to leave the secure supply of generation capacity to market forces. Each of these factors, alone or in combination, mean that generators face a ‘missing money’ problem in relation to recovering their fixed costs (Stoft, 2002). Thus separate capacity remuneration mechanisms have been proposed as a means of compensating generators for the cost of holding capacity,

separate from providing energy (Cramton and Ockenfels, 2012; Cramton and Stoft, 2008; Botterud and Doorman, 2008).

In recent years, the increase of variable renewable generation, such as wind and photovoltaic solar, in modern power systems has given rise to more calls for some form of CRM. Such generation is semi-dispatchable (i.e. can only be dispatched down) and has zero or near-zero marginal costs. Thus the units enter the market at the bottom of the supply curve and displace thermal generators, as well as depressing the prices earned by all generators in the spot market. However, given the fact that the output of renewable generators is variable and relatively unpredictable, there is still a need for excess thermal generation units to ensure sufficient supply at all hours of the year. These effects exacerbate the ‘missing money’ problem (Cramton and Stoft, 2008).

Capacity markets exist in several markets worldwide to date. In the USA, capacity markets exist in the Pennsylvania-New Jersey-Maryland (PJM), New York Independent System Operator (NYISO) and the Mid-Atlantic System Operator (MISO) markets. Bhagwat et al. (2016) provides a discussion on the experience of capacity markets in the United States to date and the potential lessons that can be learned for European policy makers and regulators. The European Commission is skeptical at best on the requirement for CRMs (European Commission, 2013). However according to Caldecott and McDaniels (2014), in 2013 European energy companies announced mothballing of over 20 GW of gas power plants, giving rise to concerns that capacity remuneration was necessary. At present in Europe, capacity payments exist or are being implemented in Spain, Portugal, Great Britain, France, Italy, and Ireland. For an extended discussion on the capacity payments under consideration, see ACER (2013) or CREG (2012).

Capacity mechanism designs can be broadly categorised as ‘price-based’ or ‘quantity-based’ ACER (2013). Price-based mechanisms provide a regulated payment designed to mimic the inframarginal-rent an otherwise-marginal generator would receive, and is distributed equally among all generators. Quantity-based mechanisms see supply companies or the System Operator contracting ahead for a fixed amount of capacity, typically equal to the expected peak demand in a given period. Within each of the price and quantity categories there are numerous types of CRMs; for an overview see Botterud and Doorman (2008) and for a more detailed discussion see De Vries (2007).

Capacity mechanisms are intended to induce sufficient capacity to cover the demand in peaking periods, as peaking units would otherwise not recover their fixed costs. It could therefore be argued that capacity payments should impact firms most during peak hours, in order to incentivise the units to be available when all units are required to produce output in order to reach demand. However,

regulators cannot observe the inherent reliability of a unit, but only their realised availability *ex post*. While capacity payment can be designed to enhance the incentive of firms to have their units available when needed most, it cannot impact on the ability of firms to ensure same, as unavailability can arise due to technical forced outages, as well as scheduled outages for maintenance and also due to strategic withholding of capacity.

While capacity markets are found in many modern electricity markets and are under consideration in many more, the optimal design of CRMs is an area of active research. Hobbs et al. (2007) considers the implications of using dynamic demand curves rather than specific demand targets in quantity-based mechanisms, and finds that demand curves reduces costs and risk for consumers and producers. Downward-sloping demand curves have been incorporated in capacity payment mechanisms in PJM and ISO-New England. Khalfallah (2011) use a dynamic model under Cournot competition, and find that ‘market-based’ mechanisms are more efficient than non-market based mechanisms in securing generation investment, but that under cartel and monopolistic situations market-based mechanisms increase installed capacities and consumer costs. Meyer and Gore (2014) consider the cross-border effects of using strategic reserve and reliability options to ensure capacity adequacy in two interconnected markets. Hoshle et al. (2015) consider the impact of increasing levels of renewable generation on various market outcomes under different capacity remuneration mechanisms.

One question which has not been addressed in the literature is the extent to which the reliability of the units themselves impacts on capacity payments, and whether and how to incentivise generators to invest in refurbishing existing generation capacity in order to improve their reliability. The reliability of a unit can be broadly interpreted, but it should not be ignored in capacity payment design. The reliability can be thought of as the number of hours of the year where the unit can be expected to be available for generation. In terms of thermal generators, the reliability is therefore one minus the forced outage rate, whereas for a renewable generator the reliability is a function of the weather, and is linked to the capacity value of the unit in question.

The reliability of generation units has an impact on market clearing prices, both directly, by seeing market prices increase when units are unavailable to generate, and indirectly, by inducing different levels of investment by generation firms, which impacts on market-clearing prices. Thus, the price paid by consumers, the total reliability of the system, the final levels of generation and the profits of generators are all dependant to some extent on the reliability of generation units. This paper considers the equilibrium prices and generation capacity that arise on a system with unreliable units.

The paper considers these market outcomes when generators, each with a given reliability,

compete in a market that includes energy and capacity payments. We consider one price-based capacity payment mechanism and one quantity-based capacity payment mechanism, both of which are found in energy markets. The effect of refurbishment of exiting units, and the impact on prices and unserved energy, is considered. A case study is presented with stylised generation firms. Cost parameters are chosen from a variety of sources and reliability and elasticity parameters are taken from the Single Electricity Market (SEM) of Ireland.

In order to model these markets, we construct the problem as a stochastic Mixed Complementarity Problem (MCP). MCPs allow the optimisation problems of multiple individual players (in our case we consider multiple electricity generation firms) to be solved simultaneously and in equilibrium by combining the Karush-Kuhn-Tucker (KKT) conditions for optimality of each of the players and connecting them via market clearing conditions. In addition, MCPs allow both primal variables (eg., power generation) and dual variables (eg., prices) to be constrained together (Gabriel et al., 2012). For instance, in the formulations to be presented, generation of all firms and prices are constrained together via an inverse demand curve.

The stochasticity of the models arises from the uncertainty surrounding the availability of units in any given period. As we wish to compare the effects of investing in new units and refurbishing existing units, we allow firms to invest in refurbishment, which increases the probability of their unit being available.

The remainder of this paper is structured as follows. Section 2 outlines the mathematical formulation of the three different capacity remuneration mechanisms considered. Section 3 describes the input data used. Section 4 outlines the results obtained. Section 5 discusses the results and section 6 concludes.

2 Methodology

Consider the case of n generation firms. The firm's objective is to maximise profits, which they earn in both energy and capacity markets.

We compare two different capacity payment mechanisms. The first mechanism is a price-based mechanism that takes the form of a capacity 'pot'. Under this mechanism, a fixed sum intended to compensate for fixed costs is calculated on the basis of the investment cost of new generation, which is determined on the basis of the cheapest generation capacity per MW available. This cost per MW is

then multiplied by the amount of generation required to meet the peak electricity demand. Thus, the pot is calculated so as to mimic the inframarginal rent an otherwise-marginal unit would require in order to break even. The rationale behind this is that an otherwise-marginal generator will always break even on their variable costs, as whenever they generate, they will always set the price, and so their energy revenues will always be exactly equal to their marginal costs. The pot is therefore calculated on the basis of the total monies that will be required in order to render generators indifferent between receiving surplus inframarginal rents at times of scarcity prices, and receiving the sum of money in the pot.

Once calculated, this pot is divided evenly among all generators on the basis of their capacity. This means when there is a surplus of generation capacity on the system, the payment per MW will be below the fixed costs of the lowest-cost generator, as the fixed pot is divided over a total amount of installed capacity which is greater than the requirement for installed capacity that was used to calculate the pot. This provides an exit signal. In contrast, should a deficit of generation arise, the payment per MW of installed capacity will be higher than the fixed costs of the lowest-cost generator, as the total pot is divided over a smaller amount of installed capacity than that used in calculating the pot. This provides an entry signal¹.

In practice, price-based mechanisms have been criticised for failing to provide a sufficiently strong exit signal, leading to overcapacity (CER and NIAUR, 2014).

The second mechanism considered is a quantity-based capacity payment mechanism. The quantity-based capacity payment we consider is that of reliability options, although there are other quantity-based mechanisms that could also be studied using this methodology. Under a reliability options framework, a policy maker, regulator or Transmission System Operator (TSO), selects a quantity of capacity required for a given period (eg., one year). An auction is then held wherein a total amount of reliability options equal to that capacity target is sold. Generators compete in the auction to hold the options. Generators therefore gain a fixed sum of money per year to compensate them for each installed unit of capacity.

A main argument in favour of capacity payments in general is that capacity payments reduce high prices that would arise in times of scarcity in order to compensate generators for their fixed costs. Such high prices are not desirable for risk-averse producers or consumers. Therefore, in return for the fixed capacity payment that compensates generators for their fixed costs, generators are expected to give up the high prices they would enjoy during scarcity periods. Reliability options explicitly allows for

¹This resembles the capacity payment mechanism which is in place in the Single Electricity Market (SEM) of Ireland at present (CER and NIAUR, 2006).

this by including a predetermined strike price as part of the mechanism. The strike price is set by the policy-maker before the reliability options auction. Recommendations in the literature for an appropriate strike price range from the marginal cost of the highest-cost unit on the system, to 25% above same. However the strike price is set, generators in possession of reliability options can be called on by the TSO to generate at this strike price whenever the energy market price rises above the strike price, thereby shielding consumers from very high spot prices. For a full description of reliability options see Vázquez et al. (2002).

The models below are solved on an annual basis, using the Weighted Annual Cost of Capital (WACC) for the investment costs and the annual fixed Operation and Maintenance costs. Firms thus decide each year whether to invest in, refurbish and/or retire generation units. Variable Operation and Maintenance costs, fuel costs and carbon costs are included in marginal costs and are determined per megawatt hour of output. As well as deciding each year which investment, refurbishment and retirement decisions to take, firms also decide what levels of generation to sell in each demand period, of which there are several per year. In our case, as outlined below, we choose five.

The models for each of the mechanisms are outlined below.

2.1 Scenario probability calculation

As mentioned above, the stochasticity of the models arises from the inherent uncertainty of the generation units regarding whether they will be available or on forced outage in a particular time period. The problem must therefore be solved over the sum of all potential combinations of units being available or on forced outage, in each time period, each weighted by its associated probability. There are thus a total of 2^{F*T} scenarios (denoted by s), where F is the total number of firms and T is the total number of generation technologies available.

The parameter $B_{f,t,s}$ is a binary indicator, describing whether firm f with technology t is available ($B_{f,t,s} = 1$) or on forced outage ($B_{f,t,s} = 0$) in scenario s . The probability of the technology being available (i.e. the probability that $B_{f,t,s} = 1 \forall f, t, s$) is determined by two factors. The first is the inherent reliability of the unit and is a parameter of the model. We denote this parameter by $R_{f,t}$. The second factor is any refurbishment decisions made by the firm, which by definition make the unit more reliable by increasing the probability that $B_{f,t,s} = 1$. These refurbishment decisions are therefore a variable of the model and are denoted by $refurb_{f,t}$.

The probability of firm f 's technology t being available is therefore given by the total reliability of the technology after any refurbishment decisions, which is calculated as $R_{f,t} + refurb_{f,t}$.

The probability of each scenario s is thus a function of the firm's $refurb_{f,t}$ decisions, and is calculated according to equation 1:

$$pr_s(refurb_{f,t}) = \prod_{f,t} (R_{f,t} + refurb_{f,t})^{B_{f,t,s}} (1 - (R_{f,t} + refurb_{f,t}))^{1-B_{f,t,s}}. \quad (1)$$

This equation follows from the definitions of $R_{f,t}$, $refurb_{f,t}$ and $B_{f,t,s}$. The first half of the expression is active only for those technologies that are available ($B_{f,t,s} = 1$), and so their contribution to the probability of the scenario is given by the reliability of the technologies ($R_{f,t} + refurb_{f,t}$). The second half of the expression is active only for those technologies that are on forced outage ($B_{f,t,s} = 0$), and so their contribution to the probability of the scenario is given by one minus the reliability of the technologies ($1 - (R_{f,t} + refurb_{f,t})$).

2.2 Capacity pot mechanism

2.2.1 Firm f 's problem

Firm f maximises their profits by choosing the amount of generation, refurbishment of existing capacity, investment in new capacity and decommissioning of existing capacity as follows:

$$\begin{aligned} \max_{\substack{inv_{f,t}, \\ gen_{f,t,p,s}, \\ gen_{f,t,p,s}^{new}, \\ exit_{f,t}, \\ refurb_{f,t}}} \sum_t & \left((inv_{f,t} + CAP_{f,t} - exit_{f,t}) * cp - (inv_{f,t} ICOST_t) \right. \\ & - (CAP_{f,t} - exit_{f,t}) MCOST_t - refurb_{f,t} RCOST_t (CAP_{f,t} - exit_{f,t}) \\ & \left. + \sum_{t,p,s} \left(pr_s(B_{f,t,s} gen_{f,t,p,s} + gen_{f,t,p,s}^{new}) (\gamma_{p,s} - MC_t) \right) \right) \end{aligned} \quad (2)$$

subject to:

$$gen_{f,t,p,s} \leq CAP_{f,t} - exit_{f,t}, \quad \forall t, p, s \quad (\lambda_{f,t,p,s}^1), \quad (3)$$

$$gen_{f,t,p,s}^{new} \leq inv_{f,t}, \quad \forall t, p, s \quad (\lambda_{f,t,p,s}^2), \quad (4)$$

$$R_{f,t} + refurb_{f,t} \leq \overline{R}_{f,t} \quad \forall t, (\lambda_{f,t}^3), \quad (5)$$

where t represents different energy technologies and p represents different time periods. The decision variables for firm f include $inv_{f,t}$, $exit_{f,t}$ and $refurb_{f,t}$ representing market investment, market exit and refurbishment decisions respectively. The decision variables $gen_{f,t,p,s}$ and $gen_{f,t,p,s}^{new}$ represent generation from existing and new capacity respectively. Each scenario s represents a different combination of units being available/unavailable.

The energy price at each period for scenario s is $\gamma_{p,s}$ while cp is the capacity price paid for each unit of installed capacity. The prices $\gamma_{p,s}$ and cp are exogenous to firm f 's problem but are variables of the overall problem and are determined via the market clearing conditions. The parameters $RCOST_t$, $ICOST_t$, $MCOST_t$ are the costs of refurbishment, investment in new generation and the maintenance cost of existing generation² for each unit respectively, while CAP and MC are the initial endowment of generation capacity and the marginal cost of production of each technology, respectively. As all firms can freely invest in new capacity, there is pressure from new entrants which brings prices to their competitive levels. A model which restricted entry would also showcase the effects of market power in the generation and capacity markets. This work may be extended in this direction at a later date.

Constraints (3) and (4) ensures that generation for given unit and time period cannot exceed the amount of installed capacity while constraint (5) provides an upper bound for the reliability of each unit. The variables in brackets alongside constraints (3) and (5) are the Lagrange multipliers associated with those constraints. All primal (decision) variables of this problem are also constrained to be non-negative.

²New investments are considered to have a lower maintenance cost, and so $MCOST$ can be thought of as the premium on maintenance costs for existing capacity over and above new capacity.

2.2.2 Market clearing conditions

The market clearing conditions that combine each of the firms' problems are

$$\sum_{f,t} B_{f,t,s} * gen_{f,t,p,s} = Z_p - E * \gamma_{p,s}, \quad \forall p, s(\gamma_{p,s}), \quad (6)$$

$$POT = cp \left(\sum_{f,t} inv_{f,t} + CAP_{f,t} - exit_{f,t} \right), \quad (cp), \quad (7)$$

where Z_p is the intercept of the demand curve for period p and E is a parameter representing the slope of the demand curve. This linear demand function follows the approach of Khalfallah (2011). Equation (7) specifies that the capacity pot, which is set administratively and so is exogenous to the problem, should be divided evenly between all installed generation. The prices $\gamma_{p,s}$ and cp are the free Lagrange multipliers associated with these constraints.

2.3 Reliability options mechanism

In the second mechanism, the firms receive capacity revenues from a quantity-based reliability options mechanism. The reliability options are allocated to firms at a price determined by a competitive auction. The objective function and constraints for each firm are similar to the pot mechanism above, with the addition that generators offer capacity into an auction and some of their capacity wins a reliability option. There is thus a new variable, $cap_ro_{f,t}$, which denotes the generation capacity owned by each firm and technology that wins a reliability option. Firms holding reliability options must also repay the difference between the spot price and a predetermined strike price when spot prices are higher than the strike price.

2.3.1 Firm f 's problem

As in Section 2.2, firm f maximises its profits by choosing the amount of generation, refurbishment of existing capacity, investment in new capacity and decommissioning of existing capacity. Additionally it now also chooses how much capacity to offer in a reliability options auction as follows:

$$\begin{aligned}
& \max_{\substack{inv_{f,t}, \\ gen_{f,t,p,s}, \\ gen_{f,t,p,s}^{new}, \\ exit_{f,t}, \\ refurb_{f,t}, \\ cap_{rof,t}}} \sum_t \left(cap_{rof,t} cp - inv_{f,t} ICOST_t \right. \\
& \quad \left. - (CAP_{f,t} - exit_{f,t}) MCOST_t - refurb_{f,t} RCOST_t (CAP_{f,t} - exit_{f,t}) \right) \\
& \quad + \sum_{t,p,s} pr_s \left((B_{f,t,s} gen_{f,t,p,s} + gen_{f,t,p,s}^{new}) (\gamma_{p,s} - MC_t) - cap_{rof,t} rebate_{p,s} \right)
\end{aligned} \tag{8}$$

subject to:

$$gen_{f,t,p,s} \leq CAP_{f,t} - exit_{f,t}, \quad \forall t, p, s \quad (\lambda_{f,t,p,s}^1), \tag{9}$$

$$gen_{f,t,p,s}^{new} \leq inv_{f,t}, \quad \forall t, p, s \quad (\lambda_{f,t,p,s}^2), \tag{10}$$

$$R_{f,t} + refurb_{f,t} \leq \overline{R}_{f,t} \quad \forall t, (\lambda_{f,t}^3), \tag{11}$$

$$cap_{rof,t} \leq inv_{f,t} + CAP_{f,t} - exit_{f,t}, \quad \forall t, (\lambda_{f,t}^4), \tag{12}$$

where all previously mentioned indices, decision variables and parameters are as described in Section 2.2. The variable $rebate_{p,s}$ represents the unit price rebate that each firm f pays in period p for scenario s for the capacity for which they hold a reliability option. This price is exogenous to firm f 's problem but is a variable of the overall mixed-complementarity problem. In addition to the extra decision variable ($cap_{rof,t}$) being constrained to being non-negative, the reliability options mechanism problem also has an extra constraint which ensures that capacity offered in the reliability options auction by firm f for technology t cannot exceed its installed capacity (see equation (12)). The variable $\lambda_{f,t}^4$ is the Lagrange multiplier associated with this constraint.

2.3.2 Market clearing conditions

The market clearing conditions include the condition that all elastic demand must be met, as in the first problem, along with a constraint that the total number of reliability options awarded must reach the predetermined target set by the regulator. The Lagrange multipliers associated with these constraints are $\gamma_{p,s}$ and cp , respectively. The rebate paid by firms holding reliability options also acts as a market

clearing condition. The rebate is paid when the electricity price, $\gamma_{p,s}$, rises above a strike price, SP , which is determined administratively and is known to the firms in advance. The market clearing conditions are:

$$\sum_{f,t} B_{f,t,s} gen_{f,t,p,s} = Z_p - E * \gamma_{p,s}, \quad \forall p,s(\gamma_{p,s}), \quad (13)$$

$$TARGET = \sum_{f,t} cap_{ro_{f,t}}, \quad (cp), \quad (14)$$

$$rebate_{p,s} = max(\gamma_{p,s} - SP, 0) \quad (rebate_{p,s}). \quad (15)$$

The overall model is a MCP given by the KKT equations for each firm, along with the market clearing conditions (13) - (15).

2.4 Nash-equilibria

The overall models are mixed complementarity problems (MCPs) given by the Karush-Khun-Tucker (KKT) conditions for each firm, along with the market clearing conditions. Each of the firms' problem's is non-convex due to the bi-linear terms associated with the $refurb_{f,t}$ variable in the objective functions. As a result the KKT conditions are necessary but not sufficient for optimality. However the stationary KKT conditions associated with the $refurb_{f,t}$ variable can be examined in isolation. Those associated with the reliability options problem are³

$$0 \leq refurb_{f,t} \perp RCOST_t(CAP_{f,t} - exit_{f,t}) - \sum_s \frac{\partial pr_s}{\partial refurb_{f,t}} ((B_{f,t,s} gen_{f,t,p,s} + gen_{f,t,p,s}^{new})(\gamma_{p,s} - MC_t)^+ - cap_{ro_{f,t}} rebate_{p,s}) + \lambda_{f,t}^3 \geq 0, \quad (16)$$

where

$$\frac{\partial pr_s}{\partial refurb_{f,t}} = (-1)^{1-B_{f,t,s}} \prod_{\substack{(\hat{f}, \hat{t}) \\ (\hat{f}, \hat{t}) \neq (f,t)}} (R_{\hat{f}, \hat{t}} + refurb_{\hat{f}, \hat{t}})^{B_{\hat{f}, \hat{t}, s}} (1 - R_{\hat{f}, \hat{t}} - refurb_{\hat{f}, \hat{t}})^{1-B_{\hat{f}, \hat{t}, s}}, \quad (17)$$

where \hat{f} and \hat{t} are dummy indices representing each firm and technology respectively except firm f with technology t . If

$$\sum_s \frac{\partial pr_s}{\partial refurb_{f,t}} ((B_{f,t,s} gen_{f,t,p,s} + gen_{f,t,p,s}^{new})(\gamma_{p,s} - MC_t) - cap_{ro_{f,t}} rebate_{p,s}) > RCOST_t(CAP_{f,t} - exit_{f,t}), \quad (18)$$

³The 'perb' notation $0 \leq a \perp b \geq 0$ is equivalent to $a \geq 0, b \geq 0$ and $a.b = 0$.

then condition (16) is only satisfied if $\lambda_{f,t}^3 > 0$ which requires $refurb_{f,t} = \overline{R}_{f,t} - R_{f,t}$ as $\lambda_{f,t}^3$ is the Lagrange multiplier associated with constraint (11). In other words, if the marginal benefit of refurbishing is greater than the marginal cost, then it is optimal for firm f to refurbish their unit with technology t to its maximum. Conversely, if

$$\sum_s \frac{\partial pr_s}{\partial refurb_{f,t}} ((B_{f,t,s} gen_{f,t,p,s} + gen_{f,t,p,s}^{new})(\gamma_{p,s} - MC_t)^+ - cap_{ro_{f,t}} rebate_{p,s}) < RCOST_t(CAP_{f,t} - exit_{f,t}), \quad (19)$$

then condition (16) is only satisfied if $refurb_{f,t} = 0$, i.e, if the marginal benefit of refurbishing is less than the marginal cost, then the optimal decision for firm f with technology t is to not refurbish at all.

Finally if

$$\sum_s \frac{\partial pr_s}{\partial refurb_{f,t}} ((B_{f,t,s} gen_{f,t,p,s} + gen_{f,t,p,s}^{new})(\gamma_{p,s} - MC_t)^+ - cap_{ro_{f,t}} rebate_{p,s}) = RCOST_t(CAP_{f,t} - exit_{f,t}), \quad (20)$$

then the marginal cost and benefit of refurbishing are the same and firm f is indifferent to the amount of refurbishment they undertake for technology t .

The KKT conditions for the pot mechanism are identical to those above with the exception of the *rebate* term which is omitted.

As a result of the conditions above, we can simplify the problem without loss of generality by assuming the firms' refurbishment decisions are binary parameters, whereby firms either refurbish their units to the maximum reliability ($refurb_{f,t} = \overline{R}_{f,t} - R_{f,t}$) or they do not refurbish their unit at all ($refurb_{f,t} = 0$). When seeking an equilibrium solution to the problem, we solve the MCP for each combination of refurbishing/not refurbishing for each of the units that can refurbish. For example, for the studies described in Section 4, there are six units with reliability less than one. Hence, we solve the MCP $2^6 = 64$ times, each time with a different combination of units refurbishing or not. We then choose the combination that gives a Nash-equilibrium for each of the firms by inspection. When the $refurb_{f,t}$ variable is considered as a parameter, each of the firms' problem's becomes convex and hence the KKT conditions are both necessary and sufficient for optimality Gabriel et al. (2012). These KKT conditions for the pot mechanism are outlined in Appendix 6.1 and the KKT conditions for the reliability options mechanism are outlined in Appendix 6.2.

2.5 Limitations of the methodology

As highlighted by Laffont and Tirole (1993), incomplete information reduces the power of incentive schemes by leading to a decrease in effort. In our case, incomplete information can lead generators to reduce their refurbishment decisions, or can decrease the incentive to maximise their units' reliability, as the reliability of units also cannot be observed directly; only the unit's realised availability can be observed *ex post*. Any investment or refurbishment decisions can only increase a unit's probability of being available in each period but cannot eliminate the possibility that a unit will be on forced outage in a peak period. There is therefore a potential for moral hazard to feature when firms do not face a penalty during periods of unavailability.

The mechanisms described in this paper may differ regarding their impacts on this potential for moral hazard, depending on the risk-aversion of the firm. As a reliability options mechanism contains an explicit penalty for unavailability during times of high prices, the potential for moral hazard is lessened, with this effect strengthening as the risk-aversion of the firm increases. This is because a risk-averse firm will make greater efforts to minimise its exposure to the rebate mechanism. The price-based pot mechanism does not distinguish between payouts according to the level of demand (or price) in each period, although it is possible to concentrate capacity revenues to peak demand periods, thereby incorporating elements of the rebate mechanism. Our models do not take account of risk-aversion, nor does it concentrate revenues to peak demand periods under either mechanism, and so cannot account for these potential effects. Future research will address the particular difficulty of asymmetric information between the regulator and the firm regarding the inherent, rather than the observed, reliability of the unit.

It should be noted that the problem as formulated here assumes quasi-linearity on the consumers' preferences as the amount spent on capacity is independent of their expenditure on energy, and vice versa. This assumption could be violated in two ways. The first is that it could be argued that consumers who pay more for capacity can spend less on energy, and vice versa. Alternatively, consumers who pay more for capacity and therefore see a higher level of reliability in electricity supply arise may be willing to pay more for energy as the quality of the energy supply has increased. This may prove more likely in a developing country with much lower reliability of supply. Accounting properly for these possibilities would involve maximising the firms' profits subject to consumers maximising their utility subject to a budget constraint, with their utility given by a function of quantity and reliability of energy supply. While estimates of the income-elasticity of demand for electricity may exist, we are not aware of any estimates of the demand for electricity as a function of the underlying reliability of the

supply. Acquiring these necessary parameters in order to solve this problem is beyond the scope of this paper. Furthermore, this problem as described is unlikely to prove feasible. For both these reasons this assumption of quasi-linearity on preferences cannot realistically be relaxed.

3 Input data

We solve the model for a simplified system with three generation technologies, five time periods and four generation firms. We chose publicly-available data and chose the installed capacities, investment and marginal costs to be as general as possible. The exceptions are the slope of the demand curve, which we take from the Irish electricity market, and the forced outage rates, which we take from the Irish and British electricity systems. We also perform sensitivities on these parameters in order to ensure the results are as generally-applicable as possible rather than applying specifically to one system.

The five time periods chosen represent summer low demand, summer high demand, winter low demand, winter high demand and winter peak demand. Intertemporal constraints are not considered and so the sequence of the demand periods is not relevant; for simplicity we show the demand intercept in each period in ascending order:

Period	1	2	3	4	5
(Z_p) (MW)	300	500	750	900	1500

Table 1: Demand intercept in each period

We consider three generation technologies which we denote as baseload, midmerit and peaking capacity. We consider pulverised coal to be roughly representative of baseload units, combined cycle gas plants as representing midmerit units and open cycle gas turbines as the peaking technology for this study. We consider the investment and maintenance costs to be fixed, as per Shortt et al. (2013) and Hirth (2013) respectively, and use the marginal costs of production from Shortt et al. (2013). Sensitivities were conducted using different marginal costs and they did not impact on the final results. The cost characteristics are given in table 2.

Firm one is an integrated firm, with investments in all three generation technologies. Firm two has baseload capacity only, firm three has midmerit capacity only and firm four has peaking capacity only. The quantities of each are given in table 3.

The total generation capacity is 1400MW, which falls 100MW short of the demand that would

Technology	Investment ($ICOST_t$)	Maintenance ($MCOST_t$)	Marginal cost (MC_t)
t	(€/MW/year)	(€/MW/year)	(€/MWh)
Baseload	100000	25	65
Mid merit	65000	12	40
Peaking	45000	7	83

Table 2: Generation cost characteristics

t	$f = 1$	$f = 2$	$f = 3$	$f = 4$
Baseload	300	300	0	0
Mid merit	200	0	200	0
Peaking	200	0	0	200

Table 3: Initial capacities ($CAP_{f,t}$) of each firm (MW)

arise in period 5 at a price of zero. This suggests that generation capacity investment may be required.

The strike price (SP) in the reliability options mechanism is set equal to the marginal cost of the most expensive unit, in this case the peaking units. The recommendation in Vázquez et al. (2002) (in which reliability options were originally proposed) is that the strike price should be 25% above the incremental cost of the most expensive unit, while Cramton and Stoft (2005) recommends setting the strike price at the cost of the most expensive unit. However, the strike price can be set at a higher (or indeed a lower) level if desired.

The initial levels of reliability ($R_{f,t}$) of installed capacity are considered fixed for each technology and firm. These reliability levels can be thought of as the forced outage rates of the units and are based on forced outage rates of units found on the Irish system as per the regulators' validated model for studying the Irish system (CER and NIAUR, 2013). The forced outage rate takes a value between zero and one, where zero indicates no reliability (i.e. the unit will be continually on forced outage) and one indicates guaranteed reliability (the unit will always be available when required). In other words, $R_{f,t}$ is the probability of being available to generate at each period⁴. These initial levels are given in table 4. Midmerit units tend to have slightly lower levels of reliability than baseload units as they are cycled more frequently (Troy et al., 2010), which adds to wear and tear on the units, and lower reliability than peaking units, as midmerit plants are online more frequently. Peaking units are used least often and so have higher reliability.

⁴Note that the reliability of each unit is independent of the period; i.e. the probability of being available to generate in a given period is independent of its availability in the previous period

	Baseload	Midmerit	Peaking
Reliability	0.965	0.955	0.985

Table 4: Initial levels of reliability for each technology and firm

Given these initial levels of reliability for baseload and midmerit units, there are six units with reliability of less than one. Hence, there are $2^6 = 64$ scenarios which must be considered, representing each possible combination of units available for generation. The probability associated with each of these scenarios is a function of the units' reliability.

The cost of refurbishment ($RCOST_t$) is a continuous variable given as a proportion of the investment cost. Thus to increase a unit's reliability from 0.4 to 0.5 costs one tenth of the investment cost. While this is a simplification, the rationale for this is that no increase in reliability should cost nothing, and to raise the reliability of a unit from zero to one entails building a new unit⁵. The reliability of new investments is assumed to be equal to one, i.e., a new build is as reliable as any unit can be expected to be.

The slope of the demand curve is calculated from historical Irish data based on Di Cosmo and Hyland (2013). We assume that residential demand is met by supply companies that contract forward for generation, and so do not consider the impact of residential demand in the analysis. Agricultural demand is also met mainly through retail markets, and furthermore is a very small percentage of total demand (2%). We therefore calculate only the slope of the curves for industrial and commercial electricity demand, at -0.20 and -0.05 respectively, and take their weighted average according to their shares in final electricity demand to represent the slope of the demand curve for electricity, -0.14.

4 Results

The model is solved for both capacity payment mechanisms with and without the possibility of investing in refurbishment. The generic algebraic modelling system (GAMS) was used to solve the models, employing the PATH solver.

⁵Future work will examine this assumption in more detail

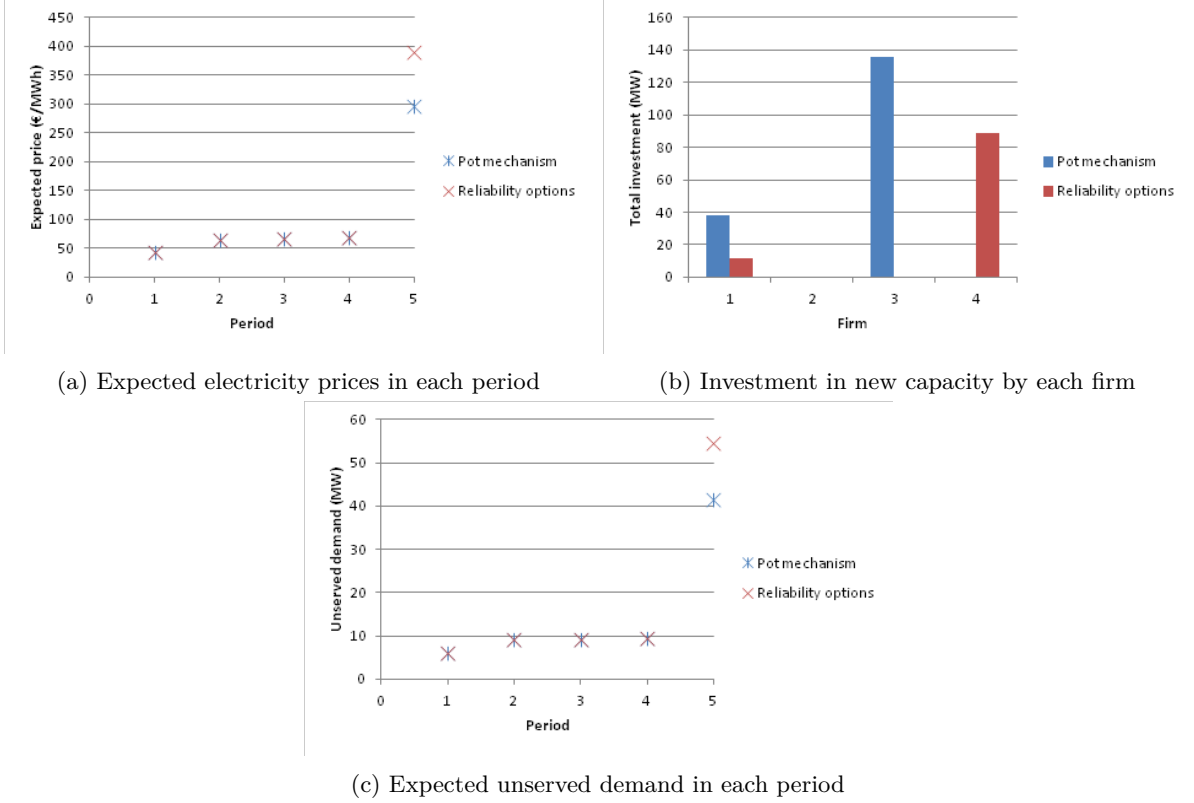


Figure 1: Results under both capacity payment mechanisms with no refurbishment

4.1 Results without refurbishment

The pot mechanism and reliability options models are first run without taking consideration of potential refurbishments, i.e., they are run with the variable $refurb_{f,t}$ set equal to zero for all firms and technologies.

4.1.1 Base case

Figure 1a shows the expected electricity price at each period, i.e. the price at each scenario weighted by the probability of the scenario ($\sum_s pr_s * \gamma_{p,s}$). There is little difference in the electricity prices arising under the two models with the exception of the peak demand period 5. In this period the market price is higher under reliability options, but due to the rebate mechanism consumers are not exposed to this high price.

Table 5 shows the prices that arise in each period for the two capacity payment designs, along with the maximum and minimum prices that arise. Prices are at a minimum when all generators are available (i.e. when no unit is on forced outage), while prices are at a maximum when all units are

on forced outage. Given the relatively high initial levels of reliability, the probability of the scenario in which all units are on forced outage is very low. Furthermore, as refurbishment is not considered here, the probability of each scenario is the same under both mechanisms, as probabilities will only change as a result of refurbishment decisions.

Period	Price		Min.			Max.		
	Pot	Options	Pot	Options	Probability	Pot	Options	Probability
1	42.20	42.20	40	40	0.91	902.05	1428.57	5.6×10^{-10}
2	65.02	65.02	65	65	0.99	2330.62	2857.14	5.6×10^{-10}
3	66.28	66.32	65	65	0.93	4116.33	4642.86	5.6×10^{-10}
4	67.88	68.12	65	65	0.85	5187.76	5714.29	5.6×10^{-10}
5	297.16	389.82	83	83	0.82	9473.48	10000.00	5.6×10^{-10}

Table 5: Expected prices along with their minimum, maximum and associated probabilities

The weighted average of unserved demand in each period again only diverges in period 5, where there is slightly higher generation (i.e. slightly lower unserved demand) under the pot mechanism. The reason for this difference in unserved demand in period 5 may be explained by figure 1b, which shows the total generation investments by each firm⁶. No exit takes place. Given the initial 1400MW of installed generation capacity, and the 1500MW of reliability options available, there is only 100MW of investment under the reliability options model. As units do not have 100% reliability, this brings about scenarios where there is insufficient generation available to meet the equilibrium demand that would arise in the absence of capacity constraints. Under the pot mechanism, however, there is a higher level of investment, leading to a more reliable system overall and thus less unserved demand. This is in spite of the fact that the pot was chosen to induce the same amount of total investment - indeed, the capacity price arising from the reliability options model is equal to the cost of peaking units, and so the total payout from consumers for capacity is equal to the size of the pot under the pot mechanism. Thus, a price-based capacity mechanism such as our pot mechanism may lead to overcapacity relative to a quantity-based model, such as reliability options.

The total consumer payments, both for energy and capacity, are 5.1% lower under the reliability options mechanism relative to the pot mechanism. This is due to the effect of the rebate mechanism, shielding consumers from high prices in period 5. Given the higher amount of capacity and thus generation under the pot mechanism, however, the difference in consumer payments per MWh of generation is 4.8%, with the pot mechanism again seeing higher payments. Thus from our initial position of slight

⁶All firms invest in peaking capacity only. A multi-period analysis may see investment in baseload or midmerit technologies

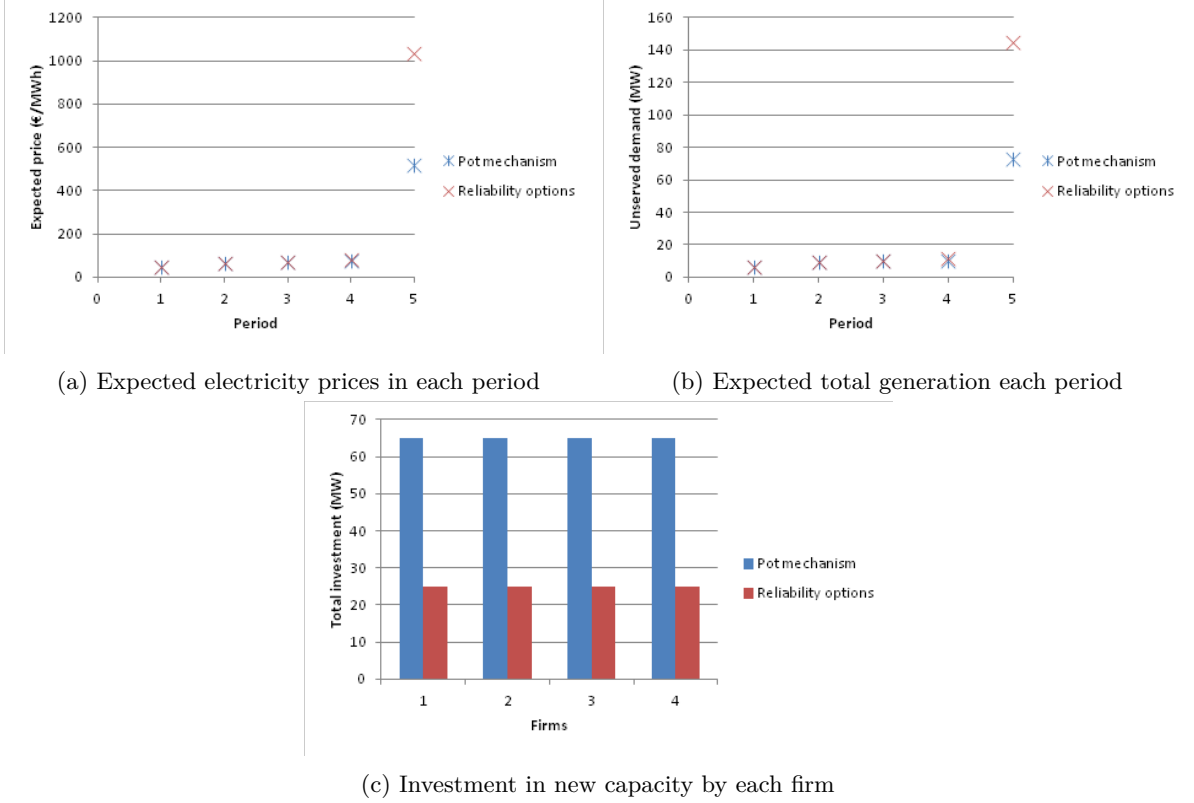


Figure 2: Results under both capacity payment mechanisms with lower levels of initial reliability

undercapacity, the reliability options model leads to a lower consumer cost, but the pot mechanism induces higher investment, which brings about more reliability and lower levels of unserved demand.

4.1.2 Varying reliability

The analysis is repeated using initial levels of reliability from National Grid in Great Britain rather than from the Irish SEM, given in table 6. These levels are lower than the initial levels seen in the SEM. The results are shown in figure 2.

Reliability ($R_{f,t}$)	Baseload	Midmerit	Peaking
GB figures	0.8786	0.89	0.9454

Table 6: Sensitivity analysis on the initial levels of reliability for each technology

Under this sensitivity, the total consumer payment under the pot mechanism is 13.3% higher than under reliability options, while the payment per MWh of generation is 11.1% higher. This is due to the fact that the probability of units being unavailable is higher, and energy prices are therefore much higher in period 5, but again the rebate mechanism shields consumers from these high prices.

The expected unserved energy also rises, but there is again higher investment under the pot mechanism, which mitigates this effect relative to the reliability options mechanism.

Unsurprisingly, expected market prices in period 5 rise under decreased reliability, as the probability of a unit being unavailable, and hence the probability of the associated scenarios arising, is increased. The expected unserved energy also increases, particularly in the case of reliability options. However higher investments under the pot mechanism bring about lower unserved demand. From this sensitivity we can conclude that lower initial levels of reliability augment the results seen in the base case regarding consumer payments and system reliability.

4.1.3 Varying initial capacities

The analysis is repeated for initial levels of over and under capacity according to tables 7 and 8. The results are shown in figure 3.

	Firm 1	Firm 2	Firm 3	Firm 4
Baseload	200	200	0	0
Mid merit	100	0	100	0
Peaking	100	0	0	100

Table 7: Initial capacity endowments ($CAP_{f,t}$) with undercapacity (MW)

	Firm 1	Firm 2	Firm 3	Firm 4
Baseload	400	400	0	0
Mid merit	300	0	300	0
Peaking	300	0	0	300

Table 8: Initial capacity endowments ($CAP_{f,t}$) with overcapacity (MW)

The effect of under and overcapacity on prices and unserved demand is as one would expect: overcapacity decreases energy prices and unserved demand while the opposite holds for undercapacity. Interestingly, equilibrium levels of unserved demand do not fall to zero even with significant overcapacity. There is no new investment in the case with overcapacity and the pot mechanism sees significantly more investment relative to reliability options with undercapacity, in keeping with the pattern observed above. In the case of undercapacity, the capacity price falls to €17 per MW, leading to significantly lower costs for consumers. However this low level of capacity price was not low enough to incentivise exit by any firms under either mechanism.

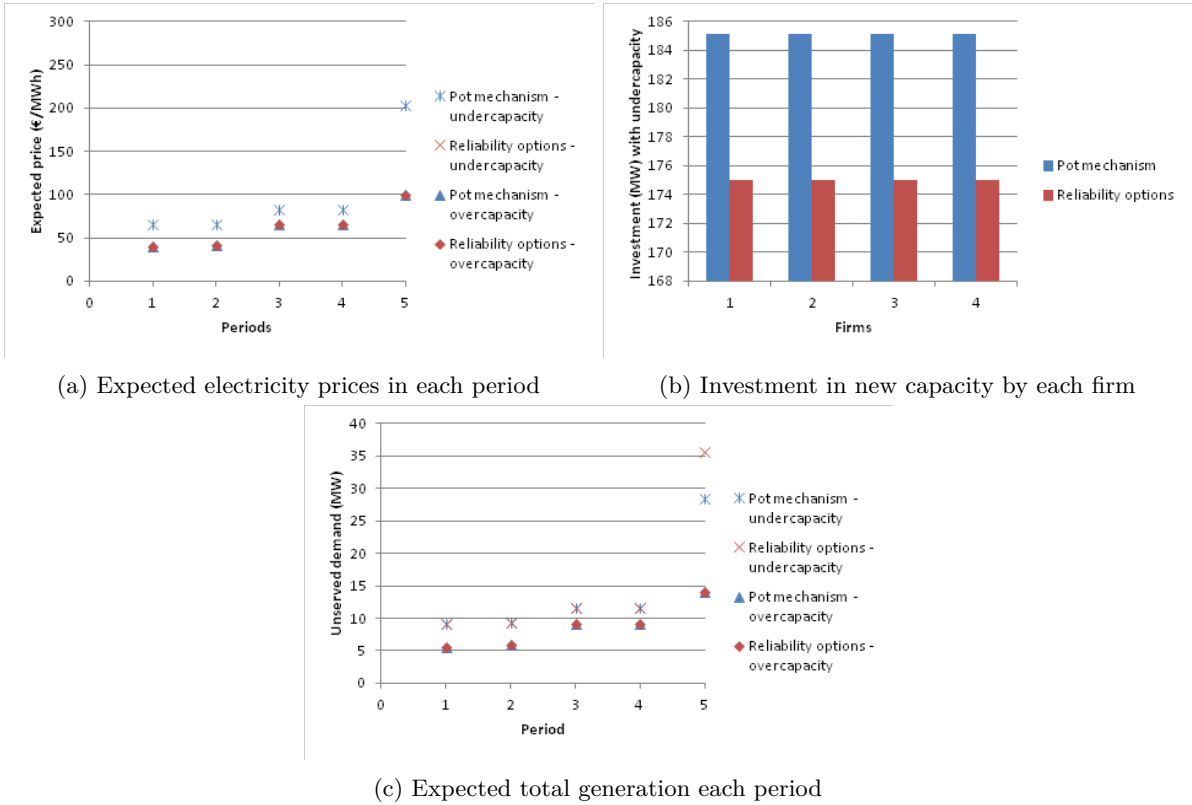


Figure 3: Results under both capacity payment mechanisms with initial over and under capacity

A further sensitivity with an extremely high level of overcapacity (ten times the initial amount) was performed. There was still no exit under the pot mechanism, as the payment per MW installed was still higher than the maintenance cost. However exit did take place under the reliability options model, leaving a total of 2620MW installed. Thus initial overcapacities of more than this amount would see exit (depending on the initial reliability of the units).

The rebate element of the reliability options mechanism operates such that a generator holding an option must repay the rebate to the system operator regardless of whether the unit was scheduled. Thus it is in firms' interest to hold both reliability options and back-up generation, to reduce the probability of their being called on to repay the difference between the strike price and the reference price and finding themselves unable to generate due to being on forced outage. This may explain the lack of exit by firms under the reliability options model.

4.1.4 Varying demand curve slope

Finally the analysis is repeated setting the slope of the demand curve to 0.05 and 0.2, which were chosen as described above. The results are presented in figure 4.

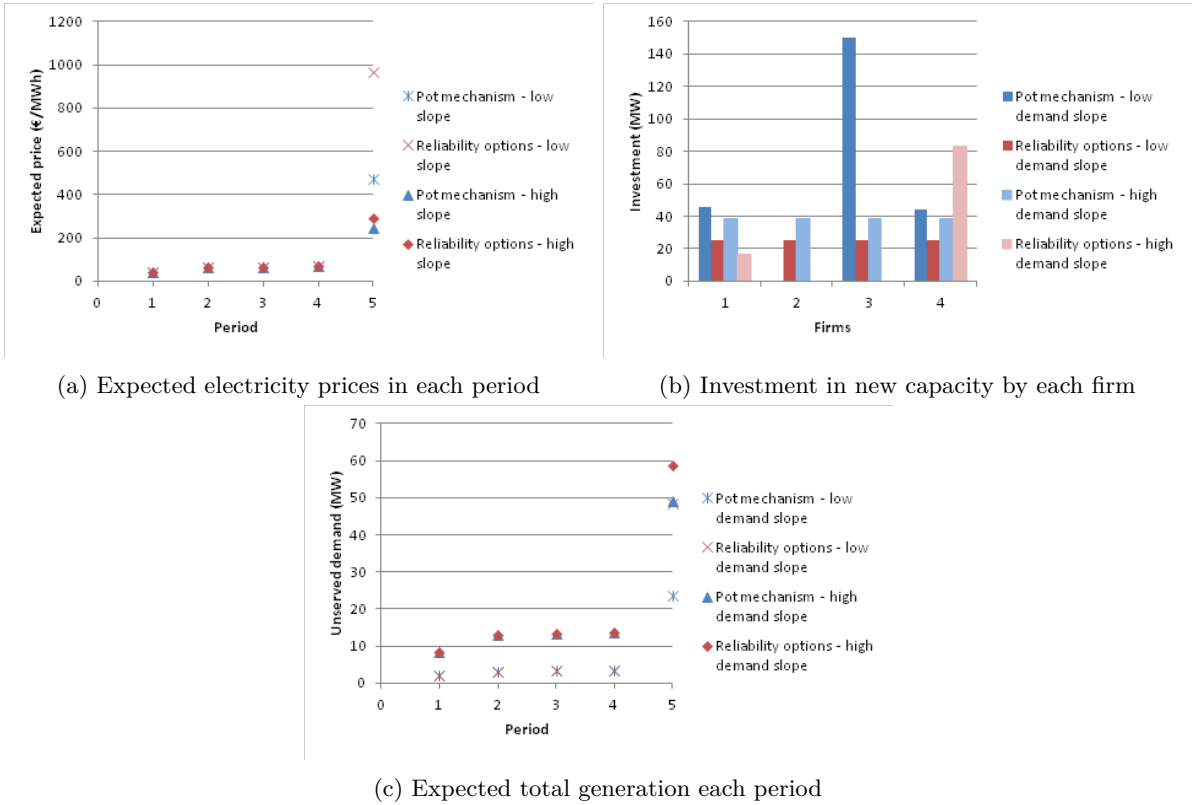


Figure 4: Results under both capacity payment mechanisms with varying levels of elasticity

The results follow the same patterns as above, with prices and unserved demand rising as the slope of the demand curve decreases. The investment decisions again see the reliability options model investing only in the generation necessary to reach the total target amount of capacity, as given by the quantity of reliability options available. This lower investment under reliability options again leads to higher levels of unserved demand.

In general it seems that in the absence of refurbishment options, a pot mechanism leads to higher consumer costs along with a lower level of unserved demand and a more reliable system. Even in the case of overcapacity, no market exit takes place.

4.2 Results with refurbishment

We repeat the analysis including the *refurb* variable; all other inputs are as per section 4.1.1 above. This allows us to isolate the effect of investing in generation units to increase their inherent reliability on costs and generation, which is one of the main contributions of this paper.

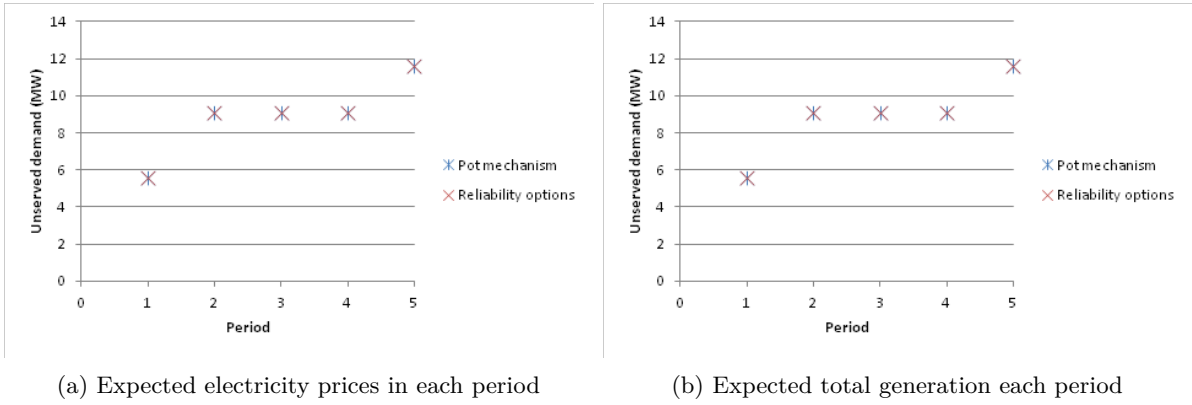


Figure 5: Results under both capacity payment mechanisms with refurbishment

4.2.1 Base case

The electricity prices and the difference in equilibrium demand and demand at price zero which arise under the base case are shown in figure 5. Total generation investment is 100MW under both mechanisms. This holds for all sensitivities performed below.

All firms invest in refurbishment of midmerit and baseload units to the maximum extent possible, bringing their reliability levels to one. This also reduces the probability of any scenario in which a unit is on forced outage to zero, with the scenario in which all units are available in all time periods occurring with probability 1. The maximum reliability explains the equal investment under each mechanism, as there is no premium to invest in surplus generation in order to allow extra generation to be available in periods of forced outage.

The increased reliability of the units on the system reduces the peak prices seen in period 5, which were being influenced by the capacity investment cost in the previous results without refurbishment. This lowers costs to consumers under the pot mechanism (as consumers were not exposed to the high prices under the reliability options mechanism in any case) relative to the non-refurbishment model. This decrease in prices in period 5 means that the total costs to the consumer is equal under the two mechanisms, as the capacity price in the reliability options model again clears at the cost of investment in peaking capacity. As the total generation is also equal under both mechanisms, the consumer cost per MW of generation is equal under both mechanisms.

The levels of unserved demand have also fallen relative to the case with no refurbishment, confirming that the forced outage of units was to some degree responsible for unserved demand.

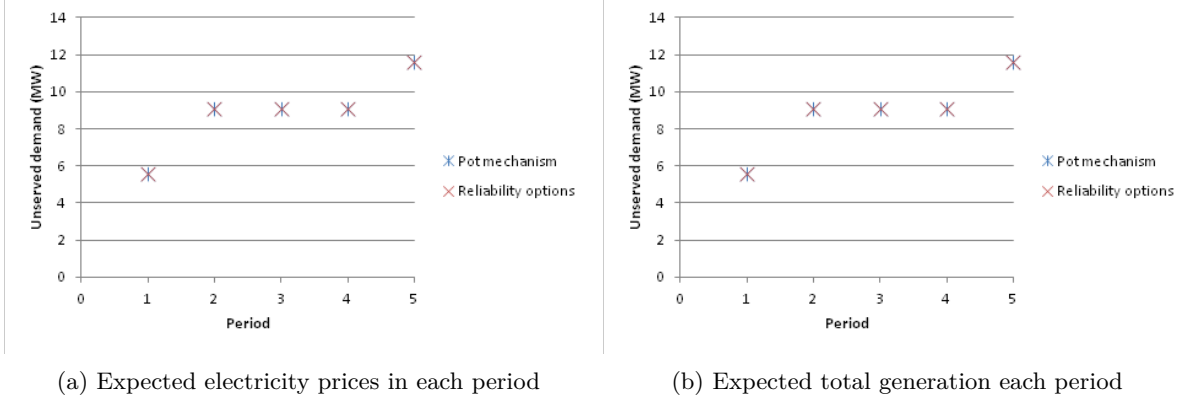


Figure 6: Results under both capacity payment mechanisms with refurbishment and varying initial levels of reliability

4.2.2 Varying reliability

The analysis is repeated with a lower level of initial reliability, as per section 4.1.2 above. The results are shown in figure 6.

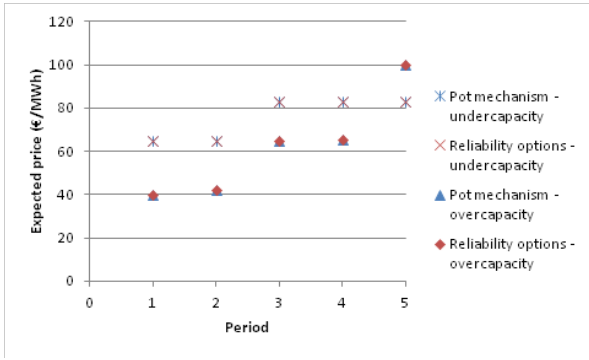
Maximum refurbishment once again takes place in all technologies, as in case 4.2.1 above. This induces the same investment in each case as above, leading to the same outcomes in terms of prices, unserved demand and consumer costs. This result is unsurprising as according to equations 18 - 20 as discussed above in section 2.4, full refurbishment will take place as long as the marginal benefit of refurbishment exceeds the marginal cost. This condition will hold (or not) depending only on the costs involved, and not on the firm's initial levels of reliability.

4.2.3 Varying initial capacity

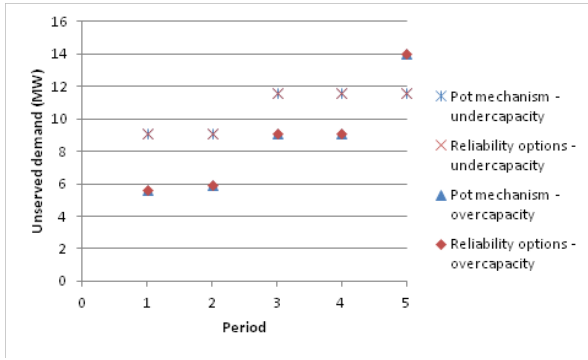
The analysis is repeated using initial over and undercapacity, as in section 4.1.3. The resulting prices, investment in the case of undercapacity and the unserved demand are shown in figure 7.

Unlike the previous two subsections, there is no refurbishment of any units, bringing their reliability to the maximum possible. There is also no exit under either mechanism. The cost of maintaining existing units is not sufficient to induce exit, even at reduced capacity revenues per MW of installed capacity.

Under the overcapacity input set, the capacity price in the reliability options model collapses to €17 per MW. For the first time with refurbishment, there is a different final resulting cost to consumers under the two models. The price and unserved demand follow the same patterns as observed in previous

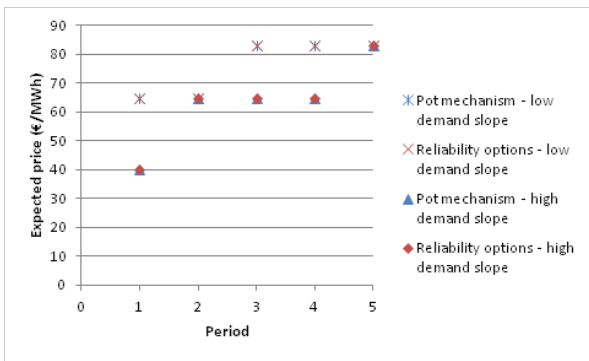


(a) Expected electricity prices in each period

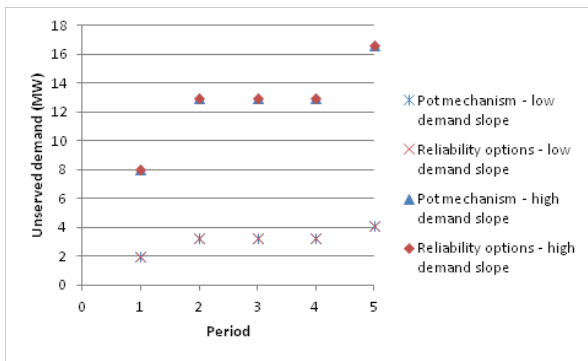


(b) Expected total generation each period

Figure 7: Results under both capacity payment mechanisms with refurbishment and initial over and undercapacity



(a) Expected electricity prices in each period



(b) Expected total generation each period

Figure 8: Results under both capacity payment mechanisms with refurbishment and varying initial levels of demand curve slope

input sets.

As above, a further sensitivity was performed whereby the initial levels of capacity were set to ten times their initial levels. As there was no refurbishment, the results of this sensitivity are the same as the results above, whereby there is no exit under the pot mechanism, and in the reliability options mechanism there is sufficient exit to bring the total capacity down to 2620MW. However the profit levels of the firms are close to zero and so it is likely that an analysis performed over a time horizon of several years would see exit.

4.2.4 Varying demand curve slope

Finally the analysis is repeated for varying levels of slope of the demand curve, as per section 4.1.4.

The refurbishment decisions follow the same pattern as before. Under the lower slope of 0.05,

the electricity price in periods 1–4 increases relative to the prices seen under a higher demand slope under both mechanisms. The price in the peak period 5, however, is €83/MWh. The consumer cost is once again equal under both mechanisms for each level of demand slope. In terms of the differences between demand slopes however, the different demand slopes do bring about a change in prices, which in turn leads to an increase in consumer costs. The higher prices seen under a lower demand slope induce a lower level of unserved demand in all periods, with no difference seen across mechanisms.

4.3 Sensitivity on the costs of refurbishment

As can be seen from the results above, any difference in the two mechanisms is present only when there is no refurbishment. The full refurbishment seen in all sensitivities in subsection 4.2 drives this result. The extent to which firms refurbish is, however, likely to be driven by the cost of refurbishment. We therefore perform several sensitivities on the cost per MW of refurbishment, setting it to 1%, 5%, 50% and 100% of the cost of investment. All other inputs are assumed to be the same as in sections 4.1.1 and 4.2.1, and refurbishment is obviously permitted.

In the lower refurbishment cost sensitivities (1% and 5% of investment cost) full refurbishment takes place by all firms, as would be expected. In the higher cost instances, no refurbishment takes place. This follows from the discussion in section 2.4.

The investment decisions and resulting electricity prices and unserved demand in the low cost sensitivities are identical to those of the base case with refurbishment, while those of the higher cost sensitivities are identical to those of the base case with no refurbishment. These sensitivities highlight the importance of the cost of refurbishment, as these decisions drive any differences in outcomes between the two mechanisms.

5 Discussion

The discussion begins by considering market outcomes when refurbishment is omitted. In these cases, the higher levels of prices seen in peak periods mean that the price-based pot mechanism imposes a higher cost on consumers relative to the quantity-based reliability options mechanism - between 2% and 13%, depending on the input set. This is due to the forced outages of units increasing the price in the peak period. Under reliability options, consumers are shielded from these high prices.

The pot mechanism also induces higher levels of investment, and therefore lower levels of unserved energy. Thus it appears that the rebate aspect of the reliability options mechanism is not sufficient to induce investment in new capacity in order to ensure availability during peak periods. Instead, total investment is restricted to the total amount of reliability options available. This is in spite of the fact that the strike price here is set at the marginal cost of the most expensive unit, while the literature recommends setting the strike price at up to 25% above this level. There may therefore be a case for introducing extra penalties during periods of non-delivery in order to encourage availability of units. This finding also highlights the importance of choosing the target level of capacity appropriately.

When there is initial over-capacity, market exit does not take place under either mechanism. Consequently, the sensitivity with overcapacity saw lower levels of unserved demand and lower prices. However, the reliability options mechanism clears at a very low price, reducing total costs for consumers, indicating that a system with overcapacity may see lower costs under a reliability options framework.

In summary, when considering the results that arose when refurbishment of units is not possible, there is a tradeoff between higher costs to consumers and higher levels of unserved demand when choosing an appropriate capacity payment mechanism.

We continue our discussion to the results that arose when refurbishment of units was allowed. In these cases, the maximum amount of refurbishment took place, reducing the need for investment in new generation. The total capacity on the system is therefore equal under all sensitivities (apart from those with overcapacity), and is equal to the demand that would arise in the peak demand period at a price of zero. In each demand period, electricity prices are equal to the marginal costs of production. The costs to consumers, and the total level of generation, are the same under both capacity payment mechanisms.

There is one exception in which different costs to consumers arise. This is the case of initial overcapacity. Under this sensitivity, there is no refurbishment, and there is also no market exit, under either capacity payment mechanism. However, the reliability options market clears at a much lower price (as in the case where refurbishment was not allowed) and so total consumer costs are lower.

It is clear that apart from the case of initial overcapacity, any difference between the two capacity payment mechanisms as modelled here arises only when there is no refurbishment allowed. When refurbishment is allowed, there is either maximum or minimum refurbishment, but in either case the two mechanisms produce identical results in terms of prices and total generation levels. Therefore, the choice of capacity mechanism may depend on the extent to which refurbishment of units is technically or

economically feasible. There may be physical limitations on the extent to which units may be refurbished to reduce their forced outage levels. The amount of refurbishment was also seen to depend on the cost of refurbishment; if the cost is too high, no refurbishment takes place, and there is a difference between the two mechanisms in terms of consumer costs and total generation. This result also suggests that under any capacity payment mechanism, firms face an incentive to refurbish to the maximum extent possible, depending on the cost of refurbishment.

Another interesting result is the lack of exit observed under both mechanisms. Furthermore, for the inputs chosen here, it appears that firms will simply retain units with relatively low reliability, rather than retire some units and refurbish others. This result of course depends on the relative costs of refurbishment and maintenance.

In terms of potential policy conclusions, policy makers in a system with significant overcapacity may choose a quantity-based mechanism such as reliability options as their capacity remuneration mechanism. However, the results suggest that, when refurbishment of units is possible, there is no reason as to why overcapacity would occur in the first place as overinvestment does not take place in equilibrium under either mechanism. Overcapacity may arise due to generators earning extra rent from energy markets through some other mechanism, leading to overcompensation and therefore excess capacity. It is therefore not clear that choosing a capacity payment mechanism to induce exit, correcting for overcompensation in some other market mechanism, would bring about an efficient outcome.

It should be noted that the assumed maximum reliability level of 1 may be unrealistic; however the relevant point is to assume that refurbishment can raise the reliability of a unit to that of a new build. The relevant result is that maximum investment in refurbishment takes place, which suggests that there is an incentive for generators to ensure their units are as reliable as possible under both capacity payment mechanisms.

There are several potential extensions for this work. The first is to relax the assumption around unlimited competition from new entrants, either by imposing extra costs on new entrants or by employing a repeated game framework which we anticipate would alter the results presented here. A dynamic analysis, wherein we model multiple years, would see the investment and exit decisions change. We anticipate investment in baseload units rather than peaking units would take place, as over the course of several years, these units would earn higher inframarginal rent during periods of high demand. This higher revenue would justify their higher capacity costs.

6 Conclusion

This paper presents stochastic mixed complementarity models to investigate the impacts of two different capacity payment mechanisms in electricity markets. The paper compares a capacity payment on the basis of a fixed central pot with a market-based reliability options method. It considers one integrated firm, holding baseload, midmerit and peaking capacity, and three firms specialising in one technology each. Generators are subject to forced outages and can refurbish their units to reduce the probability of same. The analysis is performed once where refurbishment of units is not permitted, and again where firms are free to refurbish their units to maximise their reliability.

Under the assumptions of this particular study, when no refurbishment decisions are allowed, total costs to consumers are lower under a reliability options mechanism. However, both investment and generation are higher under the pot mechanism. When refurbishment is allowed, consumer costs are equal under both mechanisms. The exception is the case of initial levels of overcapacity, where consumer costs are significantly higher under the capacity payment mechanism.

One result which held whether or not refurbishment was possible is that no market exit took place under either mechanism. Overcapacity did not naturally arise under either mechanism. Therefore this study suggests that well-designed capacity remuneration mechanisms may not prove the best tool for reducing overcapacity, but also may not be responsible for allowing overcapacity to arise in the first place. Overcapacity may be due to a conflation of factors, potentially including the capacity remuneration mechanism. Further research will attempt to identify these factors.

Acknowledgements

Lynch acknowledges funding from the Programme for Research in Third Level Institutions and is co-funded by the European Regional Development Fund (ERDF). Devine is funded by the Energy Policy Research Centre (EPRC) and also acknowledges Science Foundation Ireland award 09/SRC/E1780. We are grateful to Seán Lyons and participants at the Mannheim Energy Conference for helpful comments and suggestions. All omissions and errors are our own.

Appendix

6.1 Capacity pot mechanism

The Karush-Kuhn-Tucker optimality conditions for all firms are given below using “perb” notation, where $0 \leq a \perp b \geq 0$ is equivalent to $a \geq 0, b \geq 0$ and $a \cdot b = 0$.

$$0 \leq inv_{f,t} \perp -cp + ICOST_t - \sum_{p,s} \lambda_{f,t,p,s}^2 \geq 0, \quad \forall f, t, \quad (21)$$

$$0 \leq gen_{f,t,p,s} \perp -pr_s B_{f,t,s} (\gamma_p - MC_t) + \lambda_{f,t,p,s}^1 \geq 0, \quad \forall f, t, p, s, \quad (22)$$

$$0 \leq gen_{f,t,p,s}^{new} \perp -pr_s (\gamma_p - MC_t) + \lambda_{f,t,p,s}^2 \geq 0, \quad \forall f, t, p, s, \quad (23)$$

$$0 \leq exit_{f,t} \perp cp - MCOST_t - refurb_{f,t} RCOST_t + \sum_{p,s} \lambda_{f,t,p,s}^1 \geq 0, \quad \forall f, t, \quad (24)$$

$$0 \leq \lambda_{f,t,p,s}^1 \perp -gen_{f,t,p,s} + CAP_t - exit_{f,t} \geq 0, \quad \forall f, t, p, s, \quad (25)$$

$$0 \leq \lambda_{f,t,p,s}^2 \perp -gen_{f,t,p,s}^{new} + inv_{f,t} \geq 0, \quad \forall f, t, p, s, \quad (26)$$

$$0 \leq \lambda_{f,t}^3 \perp -R_{f,t} - refurb_{f,t} + \overline{R}_{f,t} \geq 0, \quad \forall f, t. \quad (27)$$

Equations (21)-(27), along with market clearing conditions (6) and (7), represent the full mixed complementarity problem for the capacity pot mechanism problem.

6.2 Reliability options mechanism

The Karush-Kuhn-Tucker optimality conditions for all firms in the reliability options mechanism are

$$0 \leq inv_{f,t} \perp ICOST_t - \sum_{p,s} \lambda_{f,t,p,s}^2 - \lambda_{f,t}^4 \geq 0, \quad \forall f, t, \quad (28)$$

$$0 \leq gen_{f,t,p,s} \perp -pr_s B_{f,t,s}(\gamma_p - MC_t) + \lambda_{f,t,p,s}^1 \geq 0, \quad \forall f, t, p, s, \quad (29)$$

$$0 \leq gen_{f,t,p,s}^{new} \perp -pr_s B_{f,t,s}(\gamma_p - MC_t) + \lambda_{f,t,p,s}^2 \geq 0, \quad \forall f, t, p, s, \quad (30)$$

$$0 \leq exit_{f,t} \perp -MCOST_t - refurb_{f,t} RCOST_t + \sum_{p,s} \lambda_{f,t,p,s}^1 + \lambda_{f,t}^3 \geq 0, \quad \forall f, t, \quad (31)$$

$$0 \leq cap_rof_{f,t} \perp -cp + \sum_{p,s} pr_s rebate_{p,s} + \lambda_{f,t}^3 \geq 0, \quad \forall f, t, \quad (32)$$

$$0 \leq \lambda_{f,t,p,s}^1 \perp -gen_{f,t,p,s} + CAP_{f,t} - exit_{f,t} \geq 0, \quad \forall f, t, p, s, \quad (33)$$

$$0 \leq \lambda_{f,t,p,s}^2 \perp -gen_{f,t,p,s}^{new} + inv_{f,t} \geq 0, \quad \forall f, t, p, s, \quad (34)$$

$$0 \leq \lambda_{f,t}^3 \perp -R_{f,t} - refurb_{f,t} + \overline{R_{f,t}} \geq 0, \quad \forall f, t, \quad (35)$$

$$0 \leq \lambda_{f,t}^4 \perp -cap_rof_{f,t} + inv_{f,t} + CAP_{f,t} - exit_{f,t} \geq 0, \quad \forall f, t. \quad (36)$$

Equations (28)-(36), along with market clearing conditions (13) - (15), represent the full mixed complementarity problem for the reliability options mechanism problem.

References

- Abbott, M. (2001). Is the security of electricity supply a public good? *The Electricity Journal*, 14(7):31–33.
- ACER (2013). Capacity remuneration mechanisms and the internal market for electricity. Available online: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/CRMs%20and%20the%20IEM%20Report%20130730.pdf.
- Bhagwat, P. C., de Vries, L. J., and Hobbs, B. F. (2016). Expert survey on capacity markets in the us: Lessons for the eu. *Utilities Policy*, 38:11–17.
- Botterud, A. and Doorman, G. (2008). Generation investment and capacity adequacy in electricity markets. *International Association for Energy Economics Energy Forum second quarter 2008*. Available online: http://www.iaee.org/documents/newsletterarticles/208Botterud.pdf?origin=publication_detail.
- Caldecott, B. and McDaniels, J. (2014). Stranded generation assets: Implications for european capacity mechanisms, energy markets and climate policy. Technical report, Working Paper. Smith School of Enterprise and the Environment, University of Oxford (Oxford, UK).
- CER and NIAUR (2013). Round 5 (r5) sem plexos forecast model 2013-14. Available online: http://www.allislandproject.org/en/market_decision_documents.aspx?article=a440f19a-dc21-4d5b-82f1-743c7d082bd6.
- CER and NIAUR (2006). Decision documents relating to the Single Electricity Market capacity payment mechanism. Available online: <http://www.allislandproject.org/en/capacity-payments-decision.aspx>.
- CER and NIAUR (2014). Integrated Single Electricity Market (I-SEM): High Level Design for Ireland and Northern Ireland from 2016. Consultation paper. Available online: <http://www.allislandproject.org/GetAttachment.aspx?id=75891b93-486a-4ce8-8b43-84e02699a791>.
- Cramton, P. and Ockenfels, A. (2012). Economics and design of capacity markets for the power sector. *Zeitschrift für Energiewirtschaft*, 36(2):113–134.
- Cramton, P. and Stoft, S. (2005). A capacity market that makes sense. *The Electricity Journal*, 18(7):43–54.
- Cramton, P. and Stoft, S. (2008). Forward reliability markets: Less risk, less market power, more efficiency. *Utilities Policy*, 16(3):194–201.

- CREG (2012). Study on capacity remuneration mechanisms. Available online: <http://www.creg.info/pdf/Etudes/F1182EN.pdf>.
- De Vries, L. J. (2007). Generation adequacy: Helping the market do its job. *Utilities Policy*, 15(1):20–35.
- Di Cosmo, V. and Hyland, M. (2013). Carbon tax scenarios and their effects on the irish energy sector. *Energy Policy*, 59:404–414.
- European Commission (2013). Delivering the internal electricity market and making the most of public intervention. Available online: https://ec.europa.eu/energy/sites/ener/files/documents/com_2013_public_intervention_en.pdf.
- Gabriel, S. A., Conejo, A. J., Fuller, J. D., Hobbs, B. F., and Ruiz, C. (2012). *Complementarity modeling in energy markets*, volume 180. Springer Science & Business Media.
- Grigorjeva, J. (2015). Capacity mechanisms in the EU: Nationalizing energy security? Available online: <http://www.delorsinstitute.eu/011-21313-Capacity-mechanisms-in-the-EU-nationalizing-energy-security.html>.
- Hirth, L. (2013). The market value of variable renewables: The effect of solar wind power variability on their relative price. *Energy economics*, 38:218–236.
- Hobbs, B. F., Hu, M.-C., Iñón, J. G., Stoft, S. E., and Bhavaraju, M. P. (2007). A dynamic analysis of a demand curve-based capacity market proposal: the pjm reliability pricing model. *Power Systems, IEEE Transactions on*, 22(1):3–14.
- Hoschle, H., De Jonghe, C., Six, D., and Belmans, R. (2015). Capacity remuneration mechanisms and the transition to low-carbon power systems. In *European Energy Market (EEM), 2015 12th International Conference on the*, pages 1–5. IEEE.
- Khalfallah, H. (2011). A game theoretic model for generation capacity adequacy: Comparison between investment incentive mechanisms in electricity markets. *Energy Journal*, 32(4):117–157.
- Laffont, J.-J. and Tirole, J. (1993). *A theory of incentives in procurement and regulation*. MIT press.
- Meyer, R. and Gore, O. (2014). Cross-border effects of capacity mechanisms: Do uncoordinated market design policies countervail the goals of european market integration? Technical report, Bremen Energy Working Papers.
- Shortt, A., Kiviluoma, J., and O’Malley, M. (2013). Accommodating variability in generation planning. *Power Systems, IEEE Transactions on*, 28(1):158–169.

Stoft, S. (2002). *Power system economics*. IEEE Press & Wiley-InterScience.

Troy, N., Denny, E., and O'Malley, M. (2010). Base-load cycling on a system with significant wind penetration. *Power Systems, IEEE Transactions on*, 25(2):1088–1097.

Vázquez, C., Rivier, M., and Pérez-Arriaga, I. J. (2002). A market approach to long-term security of supply. *Power Systems, IEEE Transactions on*, 17(2):349–357.