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Robustness of various capacity mechanisms to regulatory errors

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Keywords Electricity Market Investment, Capacity Mechanism, Strategic Reserve, Reliability Contract, Capacity Payment,Regulatory Inefficiency

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In the EU, several governments have introduced or are contemplating a capacity mechanism to ensure adequate investment in generation capacity. Previous research has focused on the impacts of capacity mechanisms on installed capacity and cost to consumers in case of efficient regulation. By contrast we find that the choice between capacity mechanisms may be influenced by the extent of regulatory errors as well as whether the mechanisms evaluated from the perspective of consumer cost or from a welfare perspective.

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1 Introduction

During recent years the idea that the regulator should intervene to ensure that sufficient generation capacity is constructed has regained popularity among governments Regulators in Columbia, Netherlands, Ireland, Spain, France, Germany and Great Britain have either considered or implemented some form of capacity mechanism (Vázquez u. a. 2003; Comisión der Regulación de Energía y Gas (CREG) 2006; Batlle u. a. 2007; Pöyry 2007; Department of Energy and Climate Change (DECC) 2011a; Résau de Transport d'Électricité (RTE) 2011; Elberg u. a. 2012). There are reasons both in favour and against the implementation of a capacity mechanism. The argument hinges on the degree to which liberalized energy only markets on their own, in combination with markets for long-term contracts or an additional capacity mechanism, can make sure that the welfare efficient amount of capacity is built.

Liberalized energy only markets on their own would lead to efficient investment levels in case of risk neutrality and perfect competition (Stoft 2002). As a result of risk aversion, however, generators will provide less capacity while consumers would prefer more than the amount of capacity that is efficient under risk neutrality (Neuhoff und De Vries 2004).

Markets for long-term contracts in addition to the energy only market could solve this problem by enabling a risk transfer from generators to suppliers. However, it has been shown by (Green 2004; Neuhoff und de Vries 2004) that in absence of regulatory intervention retail competition undermines the incentive to sign sufficient amounts of long-term contracts. Another reason for sub-optimal long-term contracting levels in unregulated markets may be due to market power. Following (Allaz und Vila 1993), an extensive literature has developed around the impact of markets for forward contracts (D. M. Newbery 1998; Wolak 2000; Bushnell, Mansur, und Saravia 2008; Murphy und Smeers 2010; Willems und Morbee 2010) and more recently also call options (Chao und Wilson 2004; Willems 2005; Willems und Morbee 2010) on the ability of incumbents to exert market power. Most of the authors conclude that forward markets reduce market power but some doubt remains (Murphy und Smeers 2010).

In order to ensure that a welfare efficient amount of capacity is built, different capacity mechanisms have been proposed which allow the regulator to specify the capacity target. Most of the analyses are focused on regulating the amount of option contracts (S. Oren 2000; S. S. Oren 2005; Vazquez, Rivier, und Perez-Arriaga 2002; Cramton und Stoft 2005; Cramton und Stoft 2008; Batlle und Perez-Arriaga 2008) or capacity rights (Creti und Fabra 2004; Joung, Baldick, und Kim 2009) that are purchased, but there is also a number of papers that provide a comparative analysis including several other capacity mechanisms(De Vries und Heijnen 2008; Finon, Meunier, und Pignon 2008). So far these papers have mainly analyzed the degree to which capacity mechanisms can stabilize investment cycles or lower the cost to consumers, assumption that regulatory targets are set at an efficient level. Little attention has been given to the impacts on producer welfare, or the impact that would be caused by regulatory over-procurement and other forms of regulatory error. It could be possible, that regulatory errors destroy the benefits that would have been achieved by an efficiently implemented capacity mechanism.

We aim to fill this gap by analyzing the distributional implications of capacity mechanisms as well as the impact of non-optimal capacity targets, price caps, strike prices and despatch of reserve plants on the efficiency of interventions. In section 2 we describe the investment model and the capacity mechanisms that we analyse. Sections 3 presents the results in absence of regulatory errors and section 4 analyses the impact of different regulatory errors. In section 5 we draw our conclusions about the welfare distributional impacts of capacity mechanisms and the impact of regulatory errors.

2 Electricity market investment model

In order to analyse the efficiency of different capacity mechanisms we use a strongly simplified model of the GB electricity market. Instead of a series of repetitive investment decisions, we model a single investment decision. As illustrated in Figure 1, at stage 1 of the decision process investors determine the capacity mix by adding or closing plants. This is followed in stage 2 by the uncertain realization of a load duration curve D out of a fixed set of possible load duration curves $D_y, y \in [1, .. Y]$.

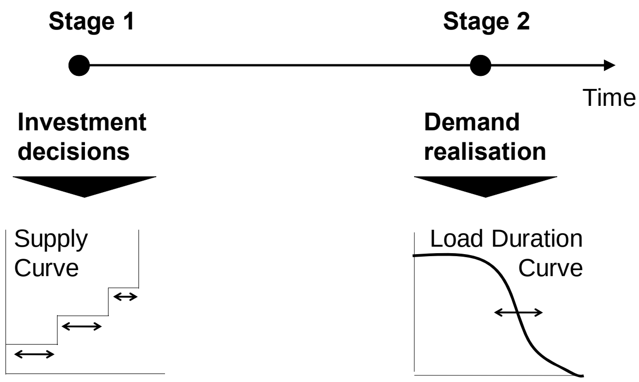


Figure 1: Sequence of decisions in the model.

We assume that the probability $Pr(y)$ of any load duration curve $D = D_y$ being realized is known to all investors in advance and is not affected by their investment decisions. We further assume that investors in our model are risk averse but not strategic, and that the fixed and variable cost of each generation technology is constant and known at the time of the investment. Within the energy markets, the price is the short run marginal cost of the most expensive unit and there are no start-up and shut-down cost so that plants are despatched in merit order. In the event of loss of load, the price in the energy market is set equal to the administrative price cap. Within our model we assume the price cap is equal to the true value of lost load. The impact of price caps above or below the true value of lost load is investigated in section 4.

For each set of capacities $\omega = (k_1^{\omega}, ..., k_J^{\omega})$ investors can therefore calculate the producer profit Π_j^{ω} that a MW of technology j would make in case of a particular realisation of the load duration curve $D = D_y$ on the basis of energy market revenues as:

$$(1) \qquad \Pi_{j,y}^{\omega} = \sum_{j1=j+1}^{J} \left[\left(D_y\left(K_{j1}^{\omega}\right) - D_y\left(K_{j1-1}^{\omega}\right) \right) \cdot \left(P_{j1} - MC_j\right) \right] - FC_j$$

Variable	Meaning	Units
$\boldsymbol{j}$	Generation technology, $j \in [1,..,J]$. Technologies are sorted by ascending marginal cost with technology J=load shedding	-
$\boldsymbol{D_y(l)}$	Cumulative duration during which load level is larger than l in load duration curve D_y	h/y
$\boldsymbol{K_j^{\omega}}$	Cumulative capacity at upper end of merit order step t in capacities set S^{ω}, $K_j^{\omega} = \sum_{j1=1}^{j} k_j^{\omega}$	MW
$\boldsymbol{p_j}$	Price at which energy is offered by technology j, $p_j = m_j$	£/MWh
$\boldsymbol{m_j}$	Marginal Cost of generation technology j	£/MWh
$\boldsymbol{F_j}$	Fixed Cost of generation technology j	£/MW

Based on the profit for different load duration curves, they can further calculate the mean and the variance of profits by weighting the profit which they would incur in case of load duration curve $D = D_y$ with the probability of this load duration curve being realised:

$$(2) \qquad E[\Pi_j^{\omega}] = \sum_{y=1}^{Y} \Pi_{j,y}^{\omega} \cdot \Pr(y)$$

$$(3) \quad Var[\Pi_j^{\omega}] = \left[\sum_{y=1}^{Y} (\Pi_{j,y}^{\omega})^2 \cdot \Pr(y) \right] - \left[\sum_{y=1}^{Y} \Pi_{j,y}^{\omega} \cdot \Pr(y) \right]^2$$

Throughout the model, risk aversion is modelled by assuming that investors base their decision on the risk discounted profits per MW:

$$(4) \qquad E_r[\Pi_j^{\omega}] = E[\Pi_j^{\omega}] - \frac{r}{2} Var[\Pi_j^{\omega}]$$

The factor r in this equation is the Arrow-Pratt coefficient of risk aversion. A larger value of r means that investors need to be paid a larger premium in order to compensate them for variation of the plant profits due to load uncertainty.
In order to calculate the set of capacities that would be provided by investors in the energy only market we use an iterative procedure that is illustrated in Figure 2 starting from the currently installed set of capacities $\omega 1$ from Figure 15 in the appendix.

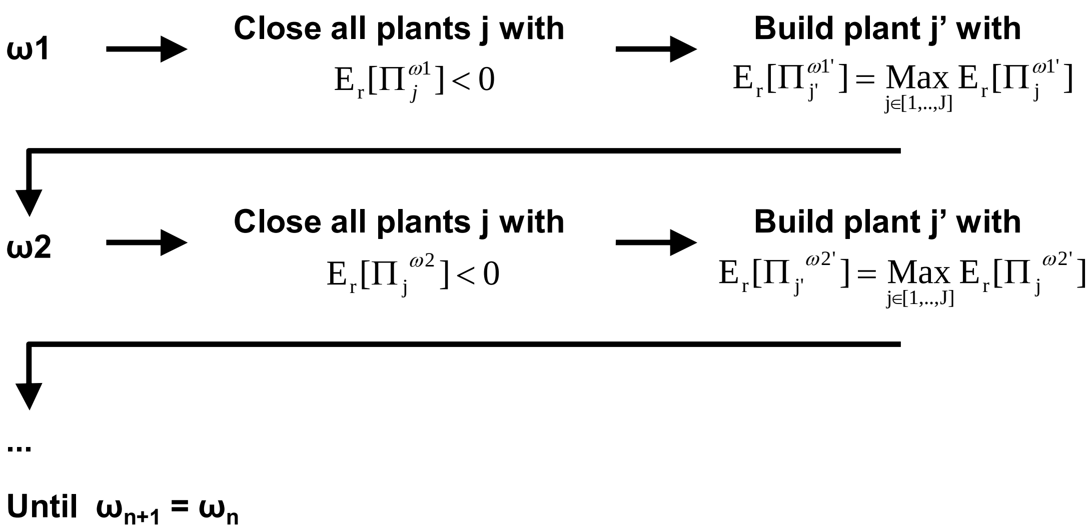


Figure 2: Iteration steps used to determine the capacity that is provided by investors in the energy only market.

In each iteration step n, the next set of capacities ω_{n+1} is calculated by closing all plants for which we expect a negative discounted profit in ω_n and then adding the plant which, on a per MW basis, would make the highest discounted profits in $\omega_{n'}$, where $\omega_{n'}$ is the original set of capacities, after closing all unprofitable plants, and plus one additional plant of the technology type j' that is investigated. That means the expected profit $E_r[\Pi_j^{\omega'}]$ is the expected discounted profit which a plant of technology j would make in the original set of capacities ω_n augmented by one additional plant of type j'. The size of the capacity increment between ω and ω' is equal to the standard unit size of technology j' in Figure 15. This procedure is repeated until $\omega_{n+1} = \omega_n$, that is all plants within ω_n are profitable, but any additional plant would not recover its cost. This heuristic is consistent with our assumption of perfect competition, as it implies that each project is evaluated independently. A similar heuristic is also used by the Department of Energy and Climate Change (Department of Energy and Climate Change (DECC) 2011b). Our insights about potential inefficiencies could therefore be directly relevant for their analyses. As a result of risk aversion, less than the optimal amount of plants may be built because the average expected profit is not enough to compensate for the variation of profits, so that the iteration stops at a lower capacity level.

This problem could be addressed by long-term contracts between market participants (Willems und Morbee 2010). However, the counterparty risk due to retail competition could limit their ability to solve the problem of under-investment (Neuhoff und De Vries 2004). Our present model does not include long-term contracts and only compares the investment levels resulting from the above iterative process based on spot market revenues against the investment levels resulting from the introduction of different capacity mechanisms in addition to spot market revenues.

A capacity mechanism can influence the total revenues of generators in three different ways. Firstly, a capacity mechanism may affect energy market revenues because the additional capacity reduces the frequency of price spikes as a result of scarcity. Secondly, a capacity mechanism may affect energy revenues by introducing a price uplift or a price cap. And thirdly, a capacity mechanism may provide an additional fixed payment in the form of a capacity premium in

addition to the energy revenues. Most capacity mechanisms use a mixture of these approaches by making capacity payments conditional on the availability of plants in the energy market.
In this paper we consider the capacity mechanisms and reference scenarios described in Box 1.

Energy Market Optimal: *The first best benchmark of welfare optimal capacity expansion.*

Energy Market Target: *The benchmark of cost optimal capacity expansion to meet regulatory capacity targets.*

Energy Market Equilibrium: *The base case, where no capacity mechanism is introduced and investment decisions are only driven by expected spot market revenues. The equilibrium is calculated using the investment heuristic of successively closing unprofitable plants and adding the most profitable plant until no further plant is profitable.*

Strategic Reserve: *The shortfall between the capacity target and the capacity provided by the EM is bought under special contracts. Price dilution for remaining generators is avoided by despatching reserve plants as last resort at a price above their marginal cost.*

Capacity Payment fixed Uplift: *The uplift that is paid per unit of capacity made available during times of scarcity is fixed in advance. This is similar to the capacity payments that were used in the former UK Pool.*

Capacity Payment fixed Total: *The total sum of annual capacity payments is fixed in advance and distributed according to the percentage of total capacity provided by each technology during scarcity periods. This is similar to the capacity payments used in the Irish SEM.*

Financial Reliability Market: *The capacity target is purchased in the form of load following call options in the capacity market. The options oblige the seller to pay back the difference between the price in the energy market and the strike price for the capacity they sold times the demand level expressed as percent of the capacity target.*

Physical Reliability Market: *Same as above, the capacity target is purchased in the form of load following call options in the capacity market. However, the call options may only be sold by owners of a power plant.*

Box 1: Overview of reference cases and capacity mechanism scenarios.

Since all of the capacity mechanisms aim to achieve a larger capacity margin they will potentially all lead to a price dilution in the energy markets.

The capacity payments and the strategic reserve reimburse the resulting missing money by dispatching the reserve at VOLL or through other forms of variable payments to generators that are available during scarcity periods.

In case of a *Capacity Payment with fixed Total*, the total sum of yearly payments is fixed in advance and re-distributed according to the availability during scarcity periods (Pöyry 2007). As we do not consider stochastic generator outages within our model, the de-rated capacity of a plant is always available. The share of the fixed payment that is received by each plant within our model thus corresponds to the share of its de-rated capacity. In our model we assume that the payment level is calibrated in such a way that the least profitable plant in the welfare optimal generation mix would break even.

In case of a *Capacity Payment with fixed Uplift*, the uplift that is paid per unit of capacity during scarcity periods is fixed in advance. Within our model we calculate the uplift in the same way as in the former UK Pool, on the basis of the loss of load probability (LOLP) at each capacity margin times the difference between the value of lost load (VOLL) and the maximum of spot price or the price offered by a generator (D. Newbery 1998). We calibrate the payment level in such a way that the least profitable plant in the welfare optimal generation mix would break even.

In case of a *Strategic Reserve,* the plant which is providing the reserve receives a fixed premium and an availability payment depending on how often it is called. In order to avoid the 'slippery slope' of a price dilution in the energy market leading to plant closures which in turn would require a larger strategic reserve, reserve plants are typically despatched as last resort, at a price between the maximum bid and the VOLL. In our model we assume that the reserve plant is despatched as last resort and priced at VOLL. We further assume that the size of the strategic reserve is calculated as the difference between the capacity target and the equilibrium capacity in the EME scenario.

Table 1 shows the variability of energy and capacity market payments, which is caused by the changes in demand levels due to economic cycles.

Table 1: Impact of economic cycles on market revenues.

	Energy Market Revenues		**Capacity Market Revenues**	
	Reces.	**Growth**	**Reces.**	**Growth**
Strategic Reserve	Low	high	No payments for plant outside reserve	
Capacity payment fixed uplift	Low	high	low	high
Capacity payment fixed total	Low	high	medium	medium
Financial reliability market	Low	medium	medium	medium
Physical reliability market	Low	medium	medium	medium

The extent to which capacity markets are able to smoothen the revenue volatility has been identified as one of the main factors that influence the cost efficiency of capacity mechanisms (De Vries und Heijnen 2008). As we can see in Table 1 one of the main weaknesses of a capacity payment with fixed uplift and a strategic reserve is that they do not provide a stable revenue stream through capacity markets, which would reduce the variation of total revenues. The capacity payment with fixed total provides a stable revenue stream, at the same time as retaining the benefit of improving availability incentives by distributing the payments on the basis of availability during scarcity periods.

Reliability markets stabilise revenues even further, as they require the generators to pay back the difference between the strike price and the reference price, which leads to a reduction of the variable energy market revenues that is compensated by further increases of the fixed capacity market revenues.

> In case of a *Physical Reliability Market*: the call options may only be sold by owners of a power plant. This is most similar to the approach that is used in Columbia (Comisión der Regulación de Energía y Gas (CREG) 2006). Since the options are load following, a generator only has to pay back the difference between the strike price and the reference price times his share of the system load. In our model we simulate this by calculating the total paybacks from all reliability contracts for each year and subtracting that share which corresponds to the ration of the de-rated capacity of a plant to the regulatory capacity target. Each plant is offering the reliability contract for its de-rated capacity at a price that corresponds to the resulting risk-discounted revenues per MW. The contract premium is equal to the maximum offer price that needs to be accepted in order to purchase the regulatory capacity target.

> In case of a *Financial Reliability Market*: the call options may be sold either by financial players or by owners of a power plant. The participation of financial players increases the liquidity in the market for reliability contracts and should prevent the contract premium from rising above the level of risk discounted expected paybacks, which may increase the economic efficiency of the mechanism in case of excessive capacity targets. This approach has so far not been implemented, but the possibility of very high spot market prices in Australia has led to a growing market for financial call options in – so called base 300 cap contracts (Australian Energy Regulator 2009).

The capacity and cost data for our model is shown in the appendix. Values for the Arrow-Pratt coefficient of risk aversion are based on (Fan, Norman, und Patt 2012).

3 Results in absence of regulatory inefficiency

In this section we analyse the impact of capacity mechanism in absence of regulatory errors. Different from most other analyses, we are not only comparing system variables - such as average cost, total welfare and installed capacity - but also considering the distributional impacts on the consumer vs. producer rent and the generation mix. We find that the cost reductions which are achieved by physical reliability markets and capacity payments with a fixed total are primarily caused by shifting rents from producers to consumers. In addition to the welfare gains caused by changes in the generation portfolio, distributional implications are thus an important factor whose size depends on the degree of competition in spot and forward markets.

The welfare optimal capacity adjustments in our example lead to total capacity of 59.6 GW which would lead to an average of 1.1 h of load shedding per year. By comparison, in case of a risk aversion rate of $r = 1e - 9$ the energy only market in our example would provide an equilibrium capacity of 59 GW and thus lead to a shortfall of 600MW compared to the welfare optimal capacity. This shortfall is explained by missing money of £9,000 /MW y that would occur in case of the welfare optimal capacity due to the risk aversion of investors. The small size of the shortfall is due to the absence of risks caused by fuel price and carbon price variations, or future investment levels. Higher levels of uncertainty should increase the amount of missing money caused by risk aversion.

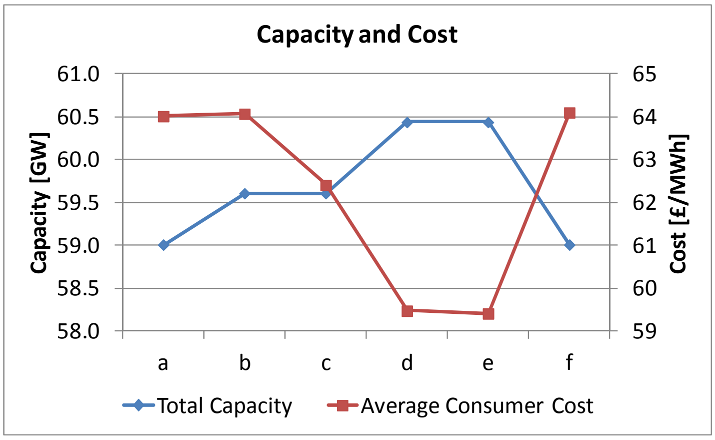


Figure 3: Capacity and consumer cost resulting from a) energy market equilibrium, b) strategic reserve, c) capacity payment with fixed uplift, d) capacity payment with fixed total, e) physical reliability market and f) financial reliability market in absence of regulatory inefficiency.

As shown in Figure 3, with the exception of the financial reliability market most capacity mechanisms are able to achieve the welfare efficient target of 59.6 GW. A financial reliability market does not lead to a capacity increase, because an additional plant would reduce to the likelihood of price spikes to a level, where the cost of purely financial contracts would be lower than the premium required by power plants. However, in absence of additional plants, the sellers of reliability contracts charge a risk premium on top of expected contract paybacks which increases the average cost to £64.1 /MWh compared to £64.0 /MWh in case of the energy only market.

A strategic reserve achieves the same total capacity as a capacity payment with fixed uplift. However, the average cost in case of a capacity payment with fixed uplift is significantly lower, because it results in a more efficient generation mix than the strategic reserve. In the current model this is caused by the fixed selection of oil as strategic reserve technology. However, even if the strategic reserve technology is chosen in a way that leads to the same technology mix, the inefficiency caused by despatching the strategic reserve as last resort still leads to a higher cost compared to the capacity payment with fixed uplift. The capacity payment with fixed total and the physical reliability market lead to an identical capacity mix and the same generation cost, because the resulting total capacity of 60.4 GW is enough to avoid load shedding even during growth years. As a result the reliability contract call option is always out of the money and therefore the payments for both mechanisms are the same.

The way how a capacity payment with fixed total and a physical reliability market achieve cost reductions despite higher capacity margins is illustrated in Figure 4.

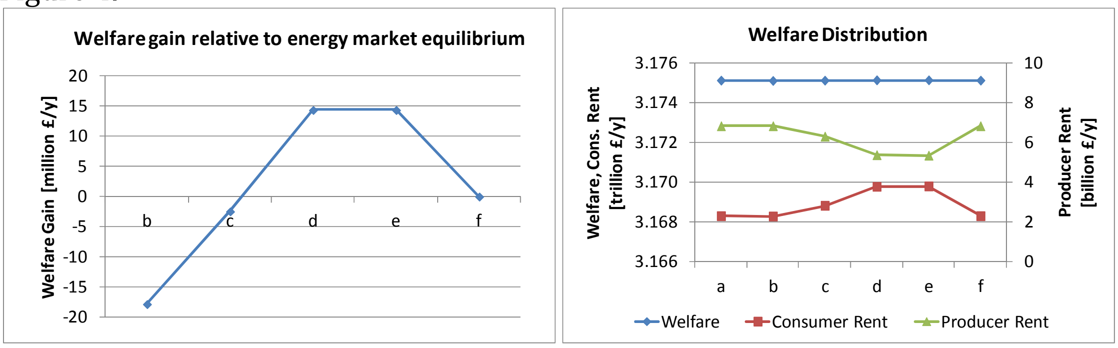


Figure 4: Welfare gain and distribution resulting from a) energy market equilibrium, b) strategic reserve, c) capacity payment with fixed uplift, d) capacity payment with fixed total, e) physical reliability market and f) financial reliability market.

The lower cost to consumers is mainly caused by a shift from producer to consumer rents (£1.5 billion/y) and to a much smaller extent by the increase in total welfare caused by the additional plant (£14 million/y). Both of these effects are achieved by the substitution of one coal plant against a nuclear plant (shift of £501 million/y, welfare gain of £32 million/y), and by reimbursing no more than required for allowing new plants to recover their cost (shift of £ 942 million/y, welfare gain of -£18 million/y).

While the substitution of coal against nuclear would also be profitable in absence of a capacity payment, it requires a coordinated action which is not detected by our investment heuristic, because the coal plant would also have been profitable. In reality this substitution could be carried out by investors with a large portfolio. Individual players could force the substitution by constructing a nuclear plant in order to displace the existing coal unit. However, this is a risky strategy and therefore less likely to occur in absence of a capacity mechanism.

Virtually all of the revenue shift from producers to consumers caused by avoiding further closures at minimum cost is based on a reduction of excess profits which could also have been brought about by a capacity charge of -£15,000/MW physical reliability market without a stabilisation of energy market revenues. The reduction of excess revenues in case of lumpy investment decisions is one of the potential benefits of a capacity mechanism.

However, the extent to which the substitution effect and the reduction of excess revenues will occur in practice depends on the competitiveness of the capacity market. In our model we have assumed perfect competition in both markets. Imperfect competition could lead to price increases in either or both markets. However, the call option reduces the potential for price increases in the spot market. As long as barriers for new entrants (e.g. site availability, liquidity requirement) are low enough so that competition in reliability markets avoids excessive prices, the net impact should still be a cost reduction for consumers.

4 Impact of regulatory errors

In this section we analyse the impact of different types of regulatory errors on the efficiency of capacity mechanisms. We then compare the impact of the worst plausible scenario for each type of regulatory error, and find that the choice of the capacity mechanism may be influenced by the extent to which the mechanism should protect against either the regulatory error of capacity over-procurement or against the error of mis-specifications of the VOLL.

One of the main risks in case of a strategic reserve despatched as last resort, is the moral hazard caused by political ***pressure to drop the reserve despatch price*** during an emergency. In our model we have investigated the impact which is caused by dropping the strategic reserve despatch price from the true VOLL at £10,000 /MWh to £1,000 /MWh with a probability of 0.1, 0.3 or 0.9 for each of the error scenarios in Table 2.

Table 2: Strategic reserve error scenarios.

	A	B	C	D
What **happens** (basis for cost calc)	VOLL	Price drop	VOLL	Price drop
What **investors believe** will happen (basis for invest. Dec.)	Price drop	Price drop	Price drop	Price drop
What **regulator assumes** investors believe (basis for strategic reserve calc)	VOLL	VOLL	Price drop	Price drop

The resulting total capacity and cost is shown in Figure 5.

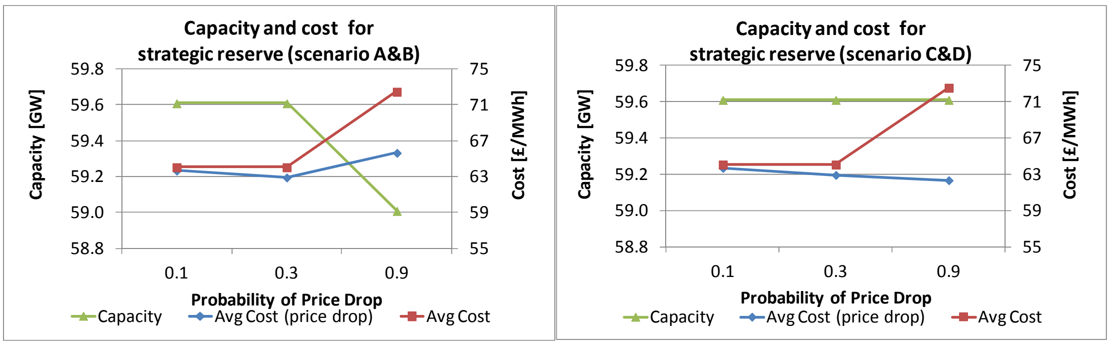


Figure 5: Impact of moral hazard on efficiency of strategic reserve.

It can be seen that the cost to consumers of maintaining a despatch at VOLL increases as the probability with which investors assume a price drop will occur increases. The attractiveness of lowering despatch prices, and hence the moral hazard, is larger, if the capacity shortfall resulting from investors' suspicion is compensated by contracting a larger reserve (scenario C and D), because a larger size of the reserve increases the impact caused by despatching at lower price. The attractiveness of SR is thus further reduced in scenario C and D compared to the base case scenario.

A ***wrong calibration of the LOLP*** has an impact both on the absolute size of capacity payments under a capacity payment with fixed uplift and on their distribution between peak and off-peak times. Following (D. Newbery 1998), we have assumed an exponential relationship between the percentage of remaining idle capacity c and the LOLP:

- $$LOLP(c) = e^{-b \cdot c}$$

In order to estimate the impact of regulatory error, we have calibrated the LOLP in the ways described in Table 3.

Table 3: Calibration process used in different LOLP error scenarios.

Scenario	LOLP Calibration Process	Result
A	Calibrate LOLP based on UK Pool payments in (D. Newbery 1998), Fig. 4.	b= 0.317
B	Calibrated LOLP so that least profitable plant in the welfare optimal generation mix would break even (Base Case)	b= 0.586
C	0.5 * Parameter Value in Scenario B	b= 0.293
D	2.0 * Parameter Value in Scenario B	b= 1.172

The resulting total capacity and cost is shown in Figure 5.

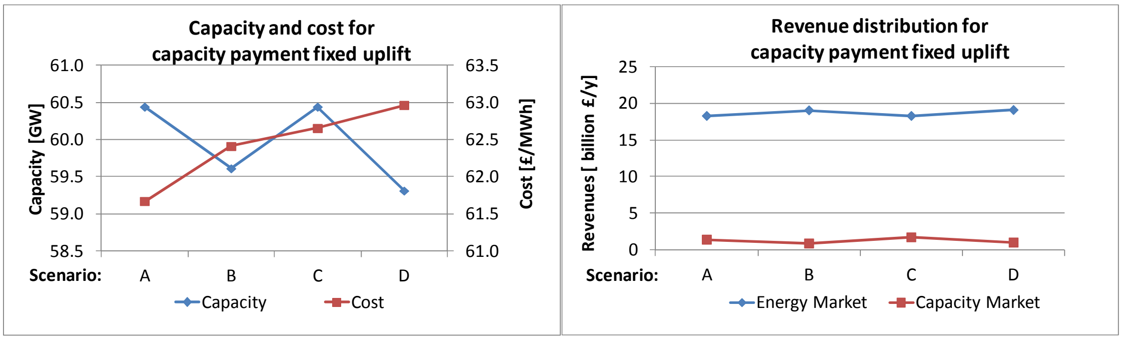


Figure 6: Impact of LOLP error scenarios A to D on efficiency of a capacity payment with fixed uplift.

Historical parameter values for the LOLP in scenario A result in 790 MW over-procurement above the welfare efficient capacity target of 59.6 GW. The parameter values for b in scenarios B and D result in a faster decline of the LOLP probability and hence lower capacity payments than in scenario A. However, the resulting closure of plants leads to price increases in the energy market which more than compensate the savings from reducing capacity payments. The capacity payments in scenario C are higher than in any other scenario, however, they are not sufficient to incentivise the construction of an additional plant and therefore only lead to a cost increase compared to scenario A.

A wrong ***choice of the strike price*** may have an impact on the efficiency of a physical reliability market, a financial reliability market and the SR. In particular, in case of a strike price below marginal cost, plants would face the risk of having to produce below cost. A too high strike price on the other hand could reduce the efficiency of a financial reliability market to attract investment, because it would reduce the share of stable income.

A variation of the strike price between VOLL and zero leads to a shift of revenues from the energy market to the capacity market, as displayed in Figure 7.

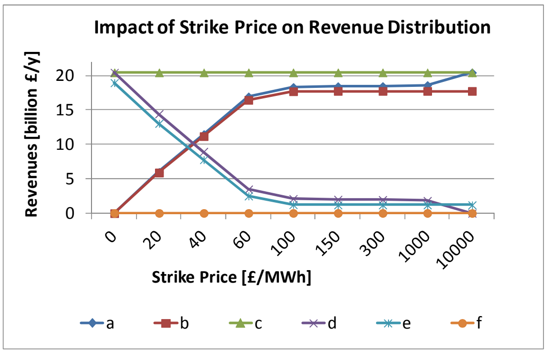


Figure 7: Impact of strike price error on energy market revenues under a) financial reliability market, b) physical reliability market, c) strategic reserve and impact on capacity market revenues under e) financial reliability market f) physical reliability market and f) strategic reserve .

In this figure we can see that, with the exception of strategic reserve, the revenues of producers in the capacity market decrease from around £20 billion/y to zero as the strike price is increased from zero to the VOLL of £10,000 /MWh. At the same time the revenues in the energy market increase from zero to around £20 billion/y. The total producer revenues remain almost constant.

As displayed in Table 4 the increase of the strike price from zero to VOLL only leads to a tiny cost reduction for consumers of about £0.1 /MWh due to the fact that in case of a strike price at zero, consumers have to pay the producers the expected energy market revenues plus a risk premium, whereas in case of a strike price at VOLL, consumers only pay the expected energy market revenues.

Table 4: Average cost resulting from different strike prices, in £/MWh.

Strike Price	0	100	1000	10000
Avg Cost, financial reliability market	64.1305	64.1064	64.0965	64.0185
Avg Cost, physical reliability market	59.4484	59.4130	59.4118	59.4118
Avg Cost, strategic reserve	64.0748	64.0748	64.0748	64.0746

This is due to the fact that in the base case the risk reduction due to stabilisation of revenues above the strike price was not sufficient to incentivise additional investment, as shown in Figure 3.

As shown in the left graph of Figure 8, in case of a higher risk aversion (Arrow-Pratt coefficient 5e-9), the revenue stabilising effect of reliability contracts does lead to additional investment for a financial reliability market compared to the energy market equilibrium. In this case, a variation of the strike price has a larger impact. However, as shown in the right hand Figure 8 for our parameter values already a strike price of £1,000 /MWh is enough to lead to incentivise additional investment. Further reductions of the strike price have a negligible impact on average cost and installed capacity.

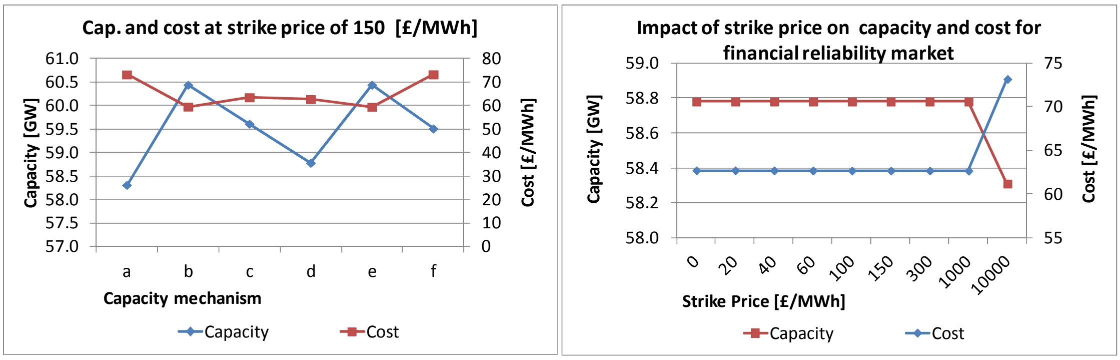


Figure 8: Capacity and cost impact of strike price on financial reliability market in case of higher risk aversion (r=5e-9) for a) energy market equilibrium b) capacity payment fixed total c) capacity payment fixed uplift d) financial reliability market e) physical reliability market f) strategic reserve.

In the energy only market, an *implicit 'capacity target'* is signaled by the duration and frequency of different price levels. These signals may be distorted by un-priced system operator actions or ***wrong estimates of the VOLL*** (Joskow 2008). The true VOLL is extremely difficult to estimate. Regulatory price caps will therefore almost inevitably be set at a level that is wrong by a large margin. In Figure 9 we show the9 impact of such a wrong VOLL. For the calculation of the average cost, we assume that the true VOLL is £10,000 /MWh, so that even if the market price during load shedding is set at a different value, the true cost for those consumers that are disconnected is still £10,000 /MWh.

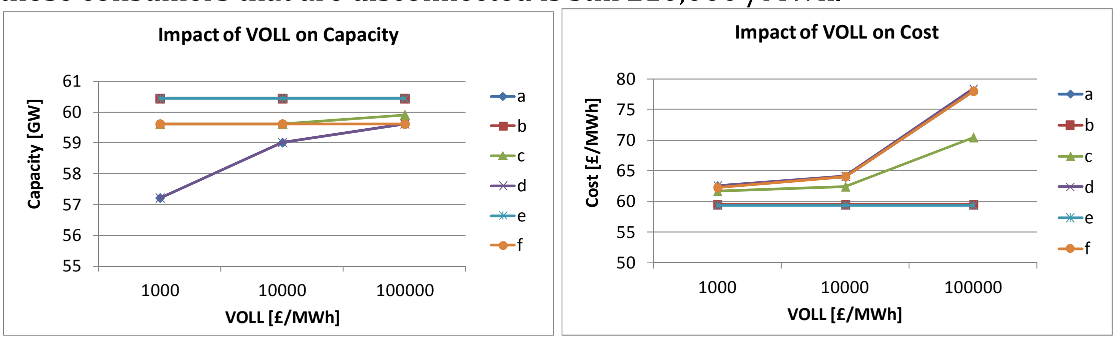


Figure 9: Impact of a regulatory depression or exaggeration of VOLL on installed capacity and average cost to consumers in case of

We can see that the usage of a wrong VOLL mainly influences the installed capacity in case of energy only markets and financial reliability markets, and the cost in case of these two as well as the cost of strategic reserve. By increasing the VOLL, energy only markets and financial reliability markets can be used to achieve higher targets, however, as capacity approximates maximum peak demand of 60.9 GW, a higher VOLL does not affect the installed capacity and only increases the cost. In our model this impact is exaggerated by the usage of a fixed de-rating factor. With this setup an additional plant would completely eliminate the possibility of load shedding and associated price spikes. In reality, an additional plant is going to reduce the probability of load shedding at each load level according to the functional relationship for the LOLP in equation 0. We would thus expect that an exponential increase in the VOLL is required in order to incentivise a linear increase in capacity. This would amplify the cost due to risk aversion. Even in case of financial reliability markets, incentivising more capacity through higher VOLL would thus seem to be inefficient, if the regulatory aim is to provide significant amounts of overcapacity. The cost and capacity of-physical reliability markets is not influenced by the VOLL, because they result in a level of capacity which eliminates the possibility of load shedding.

The explicit capacity target may be distorted because of a regulatory tendency to ***over-procure capacity***. In Figure 10 and Figure 11 we show the impact of distortions of the explicit capacity target.

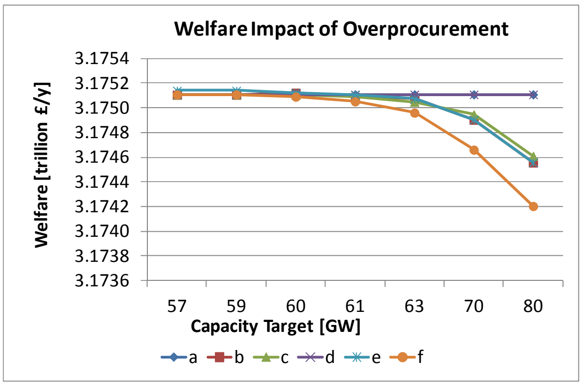


Figure 10: Welfare impact of inefficient capacity targets in case of a) energy market equilibrium, b) capacity payment fixed total, c) capacity payment fixed uplift, d) financial reliability market, e) physical reliability market and f) strategic reserve in absence of regulatory inefficiency.

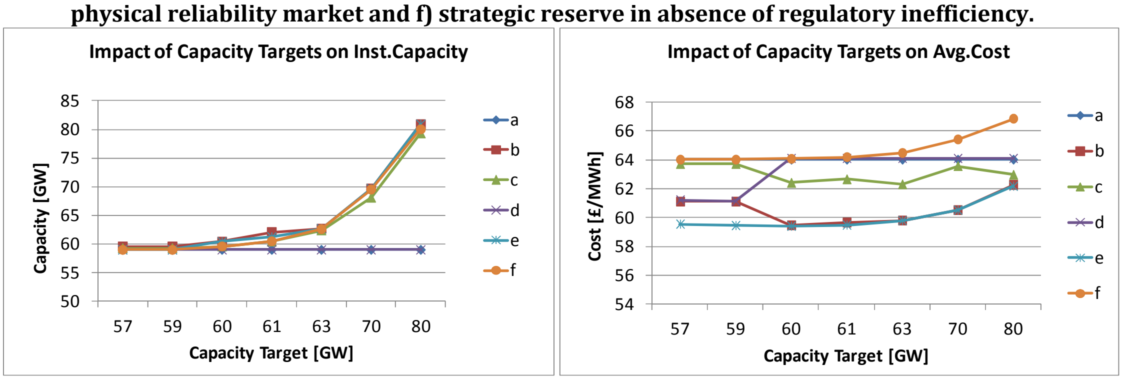


Figure 11: Impact of inefficient capacity targets on installed capacity and cost in case of a) energy market equilibrium, b) capacity payment fixed total, c) capacity payment fixed uplift, d) financial reliability market, e) physical reliability market and f) strategic reserve in absence of regulatory inefficiency.

With the exception of a financial reliability market, all capacity mechanisms achieve the capacity targets. The additional capacity in case of over-procurement leads to welfare reductions and cost increases, which are avoided by a financial reliability market. However, despite significant amounts of over-procurement of up to 80 GW, i.e. 20 GW above peak demand, most mechanisms are still able to maintain a lower cost for consumers than the energy market equilibrium or the financial reliability market.

In the last step, we then compare the impact of the worst case for each of the errors across different capacity mechanisms. The likelihood of different magnitudes of error is inevitably subjective. In absence of historical data we assume that for each of the errors the scenario with the largest impacts represents a plausible worst case. Figure 12 shows the highest impact of different errors on the average cost to consumers.

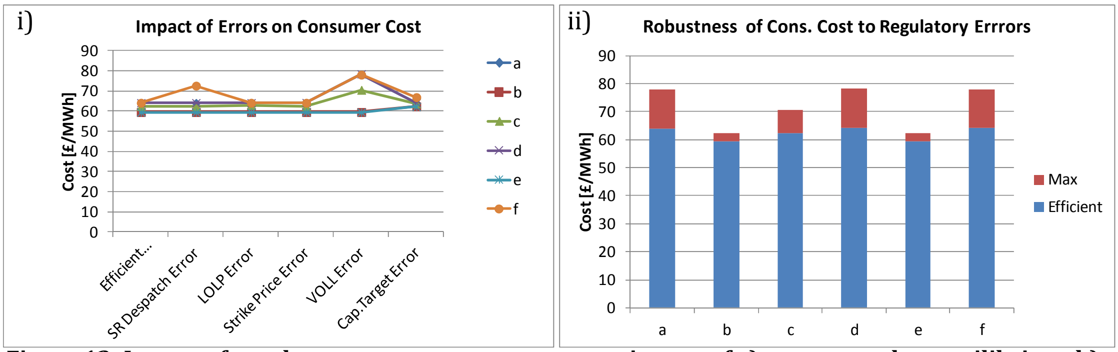
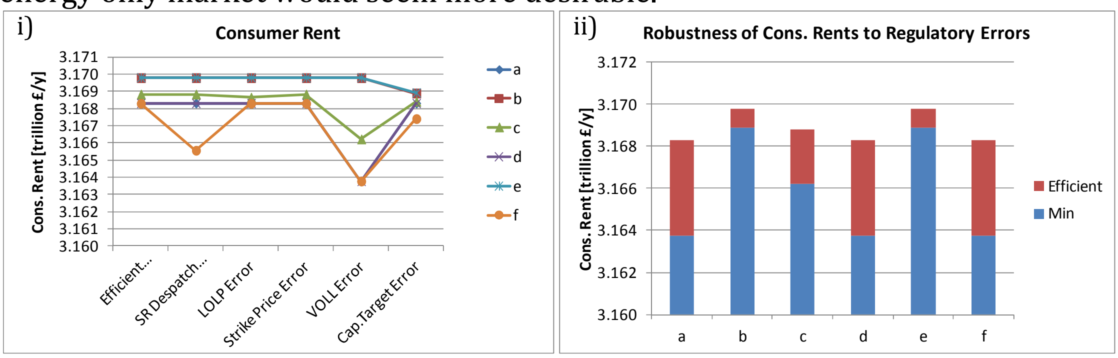


Figure 12: Impact of regulatory errors on consumer cost in case of a) energy market equilibrium, b) capacity payment fixed total, c) capacity payment fixed uplift, d) financial reliability market, e) physical reliability market and f) strategic reserve.

The first thing which we can observe in Figure 12 i) is, that out of the first three, capacity mechanism specific errors, only the error of lowering dispatch prices for the strategic reserve leads to significant cost increases while the others are negligible. The last two errors, which can affect all capacity mechanisms, on the other hand may lead to significant cost increases of up to £14/MWh in case of a VOLL error and a strategic reserve. Figure 12 ii) shows that the minimum consumer cost for each of the mechanisms as well as the largest cost increase that would be caused by imperfect regulation. The mechanisms which are most susceptible to cost increases due to regulatory errors are the strategic reserve, as well as the energy only market and the financial reliability market. One of the main reasons for the low susceptibility of capacity payments with fixed total and physical reliability markets is that these mechanisms lead to a capacity level which completely prevents load shedding. Using the current parameters, in our model these mechanisms are therefore not susceptible to estimation errors of the VOLL.

Figure 13 shows the highest impact of the different errors on consumer and producer rents. The picture is similar as before. In Figure 13 i) and iii) we can see that the largest change of revenue distribution is again caused by the moral hazard of dropping the SR dispatch prices and by the mis-estimation of the VOLL, which leads to a reduction of consumer or an increase of producer rents – depending on whether the VOLL is set too high or too low. As before, Figure 13 ii) and iv) shows that the strategic reserve, as well as the energy only market and the financial reliability market do not only lead to the highest producer and the lowest consumer rents, but are also the most susceptible to shifting further rents from consumers to producers as a result of the regulatory errors in our analysis.

From the perspective of consumers it would therefore seem most desirable to implement a physical reliability market or a capacity payment with a fixed total, while from the perspective of producers the other capacity mechanisms or an energy only market would seem more desirable.



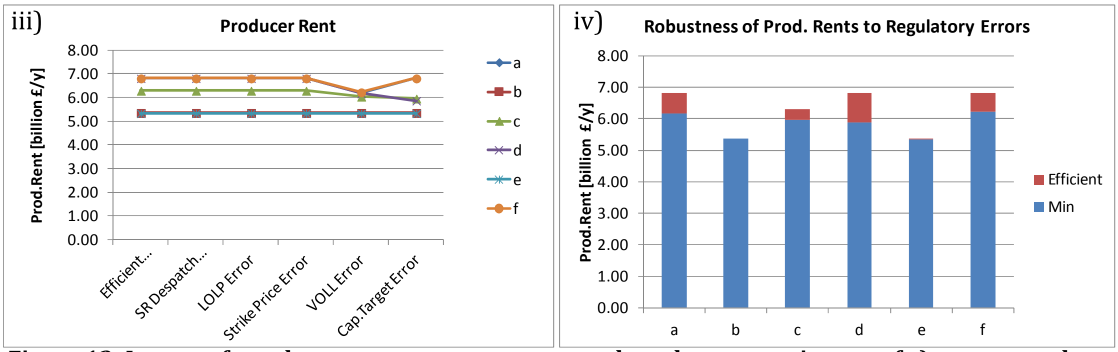


Figure 13: Impact of regulatory errors on consumer and producer rents in case of a) energy market equilibrium, b) capacity payment fixed total, c) capacity payment fixed uplift, d) financial reliability market, e) physical reliability market and f) strategic reserve.

Figure 14 finally shows the impact of regulatory errors on total welfare. In Figure 14 i) we can see that with our modeling assumptions, the main impact of the first three, mechanism specific regulatory errors is a more or less welfare neutral shift of revenues between consumers and producers. The only significant impacts on welfare are caused by VOLL errors – in case of EME and RMF – and by capacity over-procurement in case of all other capacity mechanisms.

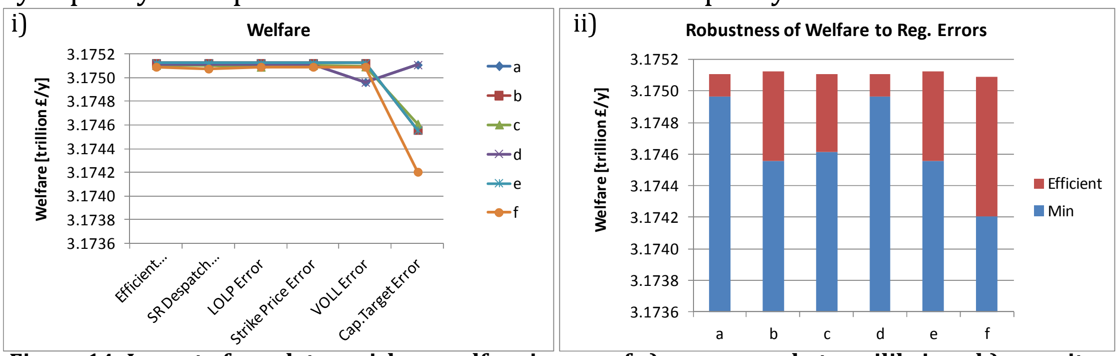


Figure 14: Impact of regulatory risk on welfare in case of a) energy market equilibrium, b) capacity payment fixed total, c) capacity payment fixed uplift, d) financial reliability market, e) physical reliability market and f) strategic reserve.

In order to maximize welfare, it would therefore seem most desirable to implement an energy only market or a financial reliability market – if the risk of wrong capacity targets is seen as more significant threat - or to implement a physical reliability market or a capacity payment with a fixed total – if the threat of VOLL mis-specification is perceived to be more significant. If our worst case estimates for both types of error are seen as equally plausible, the welfare loss which is caused by over-procurement is more significant which would lead to a preference for energy only markets and financial reliability markets. However, it is important to remember, that even though a physical reliability market or a capacity payment with fixed total are less robust to welfare reductions, they would still be preferable from the perspective of consumers because, as we could see in Figure 11, the welfare reductions caused by over-procurement are more than compensated by the revenue shifts from producers to consumers.

5 Conclusions

The standard rationale behind the introduction of capacity mechanisms is to overcome missing money due to regulatory price caps and risk aversion. A variety of analyses have shown that capacity mechanisms can be used to reduce the cost for consumers and achieve regulatory capacity targets. Our analysis confirms their findings, as well as the cost effectiveness of different mechanisms.

In order to maximise welfare in absence of regulatory errors it would seem most desirable to choose a physical reliability market or a capacity payment with a fixed total.

In case of regulatory errors, however, the welfare maximising choice of capacity mechanisms depends on the likelihood of different errors. In order to protect against welfare losses caused by regulatory over-procurement, it would be most efficient to choose an energy-only market or a financial reliability market. In order to protect against welfare losses caused by mis-specifications of the VOLL on the other hand, it would be more efficient to choose a physical reliability market or a capacity payment with a fixed total.

In addition to regulatory errors, the choice of a capacity mechanism could also be influenced by distributional considerations. In our model, physical reliability markets and capacity payments with a fixed total achieve further reductions of consumer cost by shifting revenues from producers to consumers. The revenue shift is large enough to ensure that despite the welfare loss caused by over-procurement, physical reliability markets and capacity payments with a fixed total still achieve a lower cost for consumers than the other capacity mechanisms and are thus always preferable from the perspective of consumers.

However, caution is warranted as limitations in our model could have an impact on the results. Whether or not a physical reliability market achieves revenue shifts from producers to consumers also depends on the degree of competition in the forward markets vs. the spot markets. Further research would thus be needed which includes the impact of market power in capacity and energy markets.

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7 Appendix

	Inst. Capacity	Standard Unit Size	Marginal Cost	Price	Fixed Cost Old	Fixed Cost New	Max Capacity
	GW	MW	£/MWh	£/MWh	£/MW y	£/MW y	GW
Wind	2.3	100	0	0	33,000	120,000	2.3
HydroPS	1.6	400	0	0	12,000	106,000	1.6
HydroNatFl	1.2	400	0	0	55,000	205,000	1.2
Nuclear	8	1600	9.5	9.5	72,000	378,000	-
OtherRenew	1.5	100	21.1	21.1	53,500	307,000	1.5
Coal	17.6	1600	62.4	62.4	35,000	237,000	-
CCGT	24.9	830	64.3	64.3	23,200	75,100	-
OCGT+Oil	1.2	300	80.3	80.3	23,000	70,100	-
DualFired	3.9	300	80.4	80.4	20,300	56,800	-
Oil	2.7	300	150	150	17,500	43,500	-

Figure 15: Generation cost and installed capacity.

Sources: (European Climate Foundation (ECF) 2010; Mott MacDonald 2010; Department of Energy and Climate Change (DECC) 2011c; Parson's Brinckerhoff 2011)