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The effect of Demand Response and wind generation on electricity investment and operation

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***Abstract*—We present a novel method of determining the contribution of load-shifting Demand Response (DR) to energy and reserve markets. We model DR in an Mixed Complementarity Problem (MCP) framework with high levels of wind penetration. Investment, exit and operational decisions are optimised simultaneously. We examine the potential for DR to participate in both energy and reserve markets. DR participation in the energy market reduces costs and prices but the impact of DR participation in reserve markets is limited. DR and wind generation are strongly complementary, due to the ability of DR to mitigate against the variability of wind generation, with the highest impacts of DR seen at high levels of wind penetration. DR participation in the energy market gives rise to lower equilibrium levels of investment in conventional generation and induces a Pareto improvement versus a market with no DR participation. The total impact of DR is highly dependent on specific system characteristics.**

***Index Terms*—Demand Response, Load-Shifting, Mixed Complementarity Problem, Markets, Reserve**

I. Introduction

Demand Response (DR) is the term used to describe the adjustment by consumers of their electricity consumption in response to system or market conditions. DR is capable of participating in all electricity markets, including energy and reserve markets, thereby potentially availing of multiple revenue streams that correspond to its contribution to the system [1], [2], [3], [4], [5]. DR can participate in energy markets by offering services such as load-shifting, wherein a consumer reduces load (demand) at times of high prices and increases load at times of lower prices. It has also been illustrated in the literature that DR is well-placed to provide some reserve services [6], [7], [8], [3], which we define as services that the system operator employs over various time-frames to maintain the supply-demand balance on a continuous basis [9].

Participation of DR in multiple markets may necessitate a trade-off between the services offered. Thus the optimal DR provision of multiple services should be determined by optimising DR's participation in multiple markets simultaneously. The importance of valuing DR correctly was highlighted in [10]. This paper informs the discussion on the value of DR by exploring the impact of DR participation in energy and reserve markets, simultaneously. The electricity market is modelled as a Mixed Complementarity Problem (MCP) wherein the objective functions of various electricity market participants are optimised simultaneously and in equilibrium.

MCPs have been widely deployed in the literature for electricity market analysis. Research questions addressed using MCPs include the analysis of new generation investments in energy markets [11], [12], reserve markets [13] and capacity markets [14], [15], [16].

In recent years MCPs have been used to examine price-responsive demand. Daoxin *et al.* [17] include both renewable generation and price responsive demand in their MCP. Price responsive demand is modelled through the use of a control parameter reflecting the response of consumers to changes in price. However, constraints on the price responsive demand are not taken into account and reserve provision is not considered. While there has been research examining the interaction of DR with high levels of wind penetration, reserve markets with DR participation have only been incorporated through the use of least-cost modelling [18], [19] rather than MCPs. In the first case study in [18], demand is modelled as a constant value modified by a sinusoid. Furthermore, the authors assume that DR is a fixed fraction of the total system demand at each point in time. In the second case study in [18], hourly demand and wind data is utilized and DR is assumed to be 5% of the system load in each hour.

Conejo *et al.* [20] propose an hourly real-time DR model. The demand model minimizes the cost of meeting the load minus the utility of the customers. Unlike [17], [20] includes physical constraints, as opposed to consumer or behavioural constraints, pertaining to the demand resource, including a minimum energy consumption constraint and ramping limits. Reserve provision by the DR resource is not considered.

Nekouei *et al.* [21] provide a game-theoretic approach for DR. Interplay between aggregators and generators is formulated as a Stakelberg game. The consumer minimizes load curtailment costs, while the aggregator minimizes the aggregate inconvenience of customers. Reserve provision by the demand-side is not considered. Brijs *et al.* [22] examines multiple revenue streams available to storage devices, which have similarities with DR. However they restrict their attention to energy services provision over different time scales and for different applications, and do not consider reserve provision.

The authors in [23] employ an MCP model that minimizes costs while incorporating price-responsive demand. They found there have been no generation technology mix models that consider DR with hourly varying prices and energy efficiency programs simultaneously, while including dynamic operating constraints. They propose three methodologies for integrating short-term demand responsiveness into a technology mix optimization model, one of which is a complementarity programming method [23] and utilize the same DR models in each method. The key difference with the work presented here is the manner in which the DR is represented. A reference price and quantity demanded for each hour along with elasticity assumptions are considered in [23], while this paper models a load-shifting DR resource based on heating demand data, which includes the ability to provide reserve and an energy limit constraint.

The original contributions of this paper are both methodological and data focused. On the methodological side, we include a load-shifting DR resource within an MCP framework. The optimal decisions of the DR operator are determined, rather than restricting focus to the DR operation that would prevail under least-cost modelling. The model also includes optimal investment and exit decisions by generation firms, which have not been considered in the literature to date, as well as optimal operational decisions by all parties. Our data contribution is the realistic modelling of a specific DR resource, that of electrical space and water heating, rather than considering a generic demand response as has been the case in the literature to date. Space and water heating is a particularly appropriate resource due to its inherent thermal inertia, rendering it suitable for load-shifting whilst maintaining the ability to meet customers' heating demands. These methodological contributions enable us to consider the impact of DR participation in both energy and reserve markets. Analysis of multiple service provision from DR resources within an MCP has not been considered in the literature to date. These questions are considered in the context of a generic electricity market.

The paper proceeds as follows: Section II introduces the MCP methodology employed including the DR aggregator problem. Input data and case study information is discussed in Section III. Section IV presents the results and sensitivities, Section V discusses the key findings and Section VI concludes.

II. Methodology

This section details the conventional generation firms' and DR aggregator's problems as well as the market clearing conditions, under competitive market conditions. Parameters are denoted with capital letters, primal variables with lower case letters, and Lagrange multipliers associated with the constraints with lower-case Greek letters.

A. Demand Response Aggregator's Problem

In this paper we model one DR aggregator whose problem is to choose DR in both the downward and upward direction (dr^t_{down} and dr^t_{up} respectively) and reserve provision ($reserve^t_{dr}$) so as to maximize profits from energy and reserve markets. The DR provision is determined relative to a reference demand, the energy that would be consumed by devices in the DR sector in the absence of any DR. It is assumed that, in future electricity markets, reference demands ($DREF^t$) relating to DR resources will be knowable and obtainable by DR aggregators, and that reserve markets are non-discriminatory, permitting the participation of DR. It is also assumed that DR aggregators are capable of responding to wholesale electricity market prices in realtime. The total load-shifting performed by the DR resource is the net result of a combination of dr^t_{down} and dr^t_{up}, the upwards and downwards change from the reference demand at each time, t.

The parameter $DREF^t$ represents the reference demand, or the electricity that would be consumed in the absence of any DR. The parameter $DMAX$ represents the total installed capacity of the DR resource. Equation (1a) is the objective function of the DR aggregator. The DR aggregator chooses how to participate in each market in order to maximize their profit. Equation (1b) represents the energy component of the DR aggregator's profit and consists of the revenue obtained from the energy market due to load-shifting as well as the cost of meeting the consumer's reference demand, $DREF^t$. Equation (1c) denotes the reserve component of the DR aggregator's profit. Constraint (1d) ensures that, in each time-step, t, the DR aggregator can only shift downwards and can only provide upward reserve (from the point of view of the power system) by an amount less than or equal to the reference demand. That is, the DR resource can only shift downwards and/or provide reserve if the end-user appliances are on and available. Equation (1e) constrains the upward shifting of the resource to be less than the installed capacity of the end-user appliance, $DMAX$. Constraint (1f) represents the energy limited nature of the DR resource and ensures that any shifting downwards is balanced by shifting upwards over a 24 hour period.

The DR aggregator's problem is thus:

$$\max_{\substack{dr_{down}\\ dr_{up}\\ reserve_{DR}\\ cap_{dr}}} \quad \Pi_{dr} = \Pi_{energy} + \Pi_{reserve}, \tag{1a}$$

where

$$\Pi_{energy} = \sum_t (dr^t_{down} - dr^t_{up} - DREF^t) \times \lambda^t, \tag{1b}$$

$$\Pi_{reserve} = \sum_t (reserve^t_{dr}) \times \mu^t, \tag{1c}$$

subject to:

$$dr^t_{down} + reserve^t_{DR} \leq DREF^t, \ \ (\gamma^t_1), \ \ \forall t, \tag{1d}$$

$$dr^t_{up} + DREF^t \leq DMAX, \ \ (\gamma^t_2), \ \ \forall t, \tag{1e}$$

$$\sum_{t=t'}^{t'+23} (dr^t_{down}) = \sum_{t=t'}^{t'+23} (dr^t_{up}), \ \ (\gamma^{t'}_3), \ \ \forall t' \in \{1, 25, 49, ...\}, \tag{1f}$$

The model of the DR can be adapted for different DR resources other than the water and space heaters considered here. This is easily achieved by varying the values of the parameters relating the maximum installed capacity ($DMAX$), the reference demand ($DREF^t$) and the reserve provision capabilities.

B. Generating Firm's Problem

Firm i's objective is to maximise profits, Π^i_{gen}, which they earn in energy, reserve and capacity markets, Π^i_{energy}, $\Pi^i_{reserve}$ and $\Pi^i_{capacity}$, respectively. Firms own conventional thermal generation only and participate in these markets via their investment and operation in conventional generation. There is no cost associated with reserve provision as it is assumed that the cost of providing reserve is the opportunity cost of providing energy. Wind is included as a separate player, not owned by any generation firm, whose sole function is to reduce net demand, and does not participate in either the reserve or the capacity market.

Firms choose the amount of generation ($gen^{t,i,j}$), reserve provision ($reserve^{t,i,j}_{gen}$) and their capacity bid ($cap^{i,j}_{bid}$) for all of their generating units, where j represents the generating technology and t is the time index, in this case 1-hour. Firms also choose to invest in new capacity ($invest^{i,j}$) and decommission existing capacity ($exit^{i,j}$). Each generating firm may have multiple types of generating technologies. The MCP is thus a game where the firms compete *à la* Cournot.

Firm i's objective function is Equation (2). Each generating firm chooses their profit-maximising participation in each market simultaneously. Equation (3) represents the generator's energy market profit and consists of the market price less the marginal cost $MC^{i,j}$ of producing energy multiplied by the generation. Equation (4) denotes the generator's reserve market profit. Equation (5) represents the revenue from the capacity market less investment and maintenance costs associated with capacity provision. Equation (6) constrains the power and reserve provided by a generating unit to be less than or equal to their installed capacity. Equation (7) ensures each generator's capacity bid does not exceed its installed capacity.

The parameter $ICOST^j$ represents the investment cost of generating technology j, while $MCOST^j$ is the maintenance cost associated with technology j. The parameter $CAP^{i,j}$ represents the initial endowment of generating capacity for each firm i and technology j. Firm's i's problem is thus:

$$\max_{\substack{gen\\exit\\invest\\cap}} \quad \Pi^i = \sum_j \Pi^{i,j}_{energy} + \sum_j \Pi^{i,j}_{reserve} + \sum_j \Pi^{i,j}_{capacity}, \tag{2}$$

where

$$\Pi^{i,j}_{energy} = \sum_t (gen^{t,i,j}) \times (\lambda^t - MC^{i,j}), \tag{3}$$

$$\Pi^{i,j}_{reserve} = \sum_t (reserve^{t,i,j}_{gen}) \times \mu^t, \tag{4}$$

$$\begin{aligned}\Pi^{i,j}_{capacity} = (cap^{i,j}_{bid}) \times (\kappa) - (invest^{i,j}) \times ICOST^j \\ -(CAP^{i,j} - exit^{i,j}) \times MCOST^j,\end{aligned} \tag{5}$$

subject to:

$$\begin{aligned}gen^{t,i,j} + reserve^{t,i,j}_{gen} \leq CAP^{i,j} - exit^{i,j} + invest^{i,j}, \\ (\theta^{t,j}_1), \quad \forall t, j,\end{aligned} \tag{6}$$

$$cap^{i,j}_{bid} \leq CAP^{i,j} - exit^{i,j} + invest^{i,j}, \quad (\theta^{i,j}_2), \quad \forall t, j, \tag{7}$$

The variables λ_t, μ_t and κ represent the prices associated with the energy, reserve and capacity markets receptively. Each are exogenous to the firms' problems but are variables of the overall model determined via the market clearing conditions. All of the generating firms' primal variables are constrained to be non-negative.

C. Market Clearing Conditions

The market clearing conditions vary depending on the scenario under investigation. The first market clearing condition models the energy market when DR is not considered:

$$\sum_{i,j} gen^{t,i,j} = DEM^t + E \times \lambda^t, \quad \forall t, \quad (\lambda^t), \tag{8a}$$

where the parameter DEM^t denotes the demand intercept in hour t. The parameter E represents the slope of the demand curve, and so this market clearing condition incorporates price-responsive demand (assuming E is non-zero). This price-responsive load is distinct from the DR resource's load shifting. When DR is included Equation (8a) becomes:

$$\sum_{i,j} gen^{t,i,j} = DEM^t - DREF^t + dr^t_{up} - dr^t_{down} + E \times \lambda^t \quad \forall t, \quad (\lambda^t). \tag{8b}$$

The market clearing conditions for the reserve market, with and without DR participation, are:

$$\sum_{i,j} reserve^{t,i,j}_{gen} = RESERVE_{REQ} \quad \forall t, \quad (\mu^t), \tag{8c}$$

$$\sum_{i,j} reserve^{t,i,j}_g en + reserve^t_{DR} = RESERVE_{REQ} \quad \forall t, \quad (\mu^t), \tag{8d}$$

The market clearing condition for the capacity market, in which DR does not participate, is

$$\sum_i cap^i_{bid} = TARGET, \quad (\kappa), \tag{8e}$$

The parameter $RESERVE_{REQ}$ is the total reserve required and the parameter $TARGET$ represents the amount of generation capacity required.

The MCP models are developed in the General Algebraic Modeling System (GAMS) and solved using the PATH solver [24]. The market clearing conditions presented in the previous section are utilized in conjunction with the firms' problems and the DR aggregator's problem in different combinations in order to produce a number of different MCP models. The models in Table I model DR participation in various combinations of markets. In these cases, conventional generation firms participate in energy, reserve and capacity markets. The models are run both with and without price-responsive demand.

TABLE I
MCP MODELS CONSIDERED

DR Participation	Case 1	2	3
Energy	—	✓	✓
Reserve	—	—	✓
Capacity	—	—	—

TABLE II
INITIAL ENDOWMENT OF CAPACITY $CAP^{i,j}$ FOR EACH FIRM AND TECHNOLOGY TYPE (MW)

	f1	f2	f3	f4	f5	f6	Sum
BL	1000	800	500	500	400	—	3200
MM	—	500	400	—	400	—	1300
PK	—	—	200	300	200	200	900
	1000	1300	1100	800	1000	200	5400

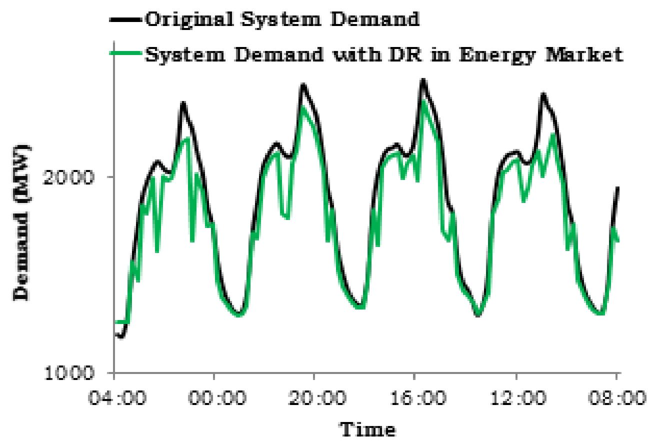

Fig. 1. System demand with the addition of demand response over a four day period for a peak load of 2500 MW with no wind generation (E=-0.11)

III. INPUT DATA

A. System Data

The models are run in a stylised electricity market with six conventional generation firms and a single DR aggregator. The initial endowment of capacity for each firm $CAP^{i,j}$ is shown in Table II and the corresponding cost characteristics are presented in Tables III and IV. The costs data are all based on the values employed in [16] with some variation between the marginal costs for each unit within each technology group.

The reserve requirement, $RESERVE_{REQ}$, is 500 MW unless otherwise stated. This level broadly complies with the reserve requirements for different levels of installed wind for the Irish power system [25]. The capacity target, $TARGET$, is 1.2 times the system peak load. All players are assumed to be price-takers.

B. Demand and wind data

The consumer end-use heating time series obtained by the methodology in [26] are used as the parameter $DREF^t$. The installed capacity, $DMAX$, is 556 MW. An annual system demand profile from Ireland for the year 2009 [27] is scaled linearly as appropriate to produce the parameter DEM^t, with peak load levels of 2500MW, 5000MW and 7500MW. For example, when peak load in the following sections is stated to be 7500 MW then, for each hourly timestep, DEM^t is 1.5 times that of when peak load is stated to be 5000 MW. This allows us to model cases of over and undercapacity. The analysis is performed for the first 100 days of the year, which covers the winter peak demand and captures the impact of capacity constraints. Wind capacity factors are determined based on historical Irish wind data, also from 2009. The slope of the demand curve (E) is set at -0.11 as determined by Di Cosmo & Hyland [28].

TABLE III
MARGINAL COST OF EACH FIRM (€/MW)

	f1	f2	f3	f4	f5	f6
BL	30	45	55	55	65	—
MM	—	50	35	—	35	—
PK	—	—	93	83	93	93

TABLE IV
INVESTMENT AND ANNUAL MAINTENANCE COSTS (€/MW)

	$MCOST^j$	$ICOST^j$
BL	25	100000
MM	12	65000
PK	7	45000

IV. RESULTS

A. Equilibrium prices and investment

Considering DR participation in energy markets only, the first immediate effect of DR participation in the energy market only is on the demand profile. DR reduces system demand peaks and increases system demand at the troughs as shown in Figure 1. While this result is as expected it validates the model and methodology.

When DR participates in reserve as well as energy markets the results are similar. In particular, the reserve price (μ^t) is €0 with and without DR participation in the reserve market. This is because the capacity target of 1.2 times the peak demand dominates the reserve requirement of 500MW. Conventional generation firms, having invested in capacity to meet the capacity target, can meet the reserve requirement at any demand level and so the reserve constraint does not bind. The value of the Lagrange multiplier on that constraint, μ^t, is therefore consistently zero. Intuitively, the revenue from the capacity market drives investment decisions, rather than reserve market revenue. Furthermore, there is no incentive for DR to change its operational strategy and so DR's participation in the energy market is unchanged. Thus the electricity price is also unchanged by DR participation in reserve markets.

Table V displays the capacity price, κ, associated with a peak load of 2500 MW, with and without price-responsive demand (E=-0.11 and E=0 respectively). When there is no price-responsive demand, DR increases the capacity price from

TABLE V
CAPACITY PRICES, κ, FOR 2500 MW OF PEAK LOAD AND WITH A RESERVE REQUIREMENT OF 500 MW AND NO WIND

	DR Market Participation		
E	**No DR**	**Energy**	**Energy & Reserve**
$E = 0$	€3.35	€7	€7
$E = -0.11$	€7	€7	€7

€3.35 to €7 per MW. This is because price-responsive demand reduces demand at the peak (as opposed to shifting demand from peak to off-peak, which is the function of the load-shifting DR resource modelled), leading to lower equilibrium levels of installed capacity. This increases the marginal value of capacity and thus the capacity price. The capacity price of €7 equates to the maintenance cost of the marginal unit, which is a peaking unit.

B. Consumer Costs

In determining consumer costs, Equation (9) is used for the models without DR, while Equation (10) is employed for the models with DR. These costs are the total costs incurred by consumers, rather than the fuel, carbon and other costs incurred by the generating firms.

$$\begin{aligned} Cost_{NoDR} = &\sum_{t,i,j}(Gen^{t,i,j} \times \lambda^t + reserve_{Gen}^{t,i,j} \times \mu^t) \\ &+ \sum_{i,j}(Cap_{Bid}^{i,j}) \times \kappa \\ &+ WIND^t \times \lambda^t \end{aligned} \tag{9}$$

$$\begin{aligned} Cost_{DR} = &\sum_{t,i,j}(Gen^{t,i,j} \times \lambda^t + reserve_{Gen}^{t,i,j} \times \mu^t) \\ &+ \sum_{i,j}(Cap_{Bid}^{i,j}) \times \kappa \\ &+ \sum_{t}(reserve_{DR}^{t} \times \mu^t) \\ &+ WIND^t \times \lambda^t \end{aligned} \tag{10}$$

DR induces a 6% reduction in consumer costs whether or not there is price-responsive demand. This result concurs with [29]. The reduction in consumer costs is primarily as a result of lower electricity prices. These cost savings confirm that there is a likely integration benefit associated with DR [10].

C. Generator Profit

Figure 2 shows the firms' profits with DR participation relative to no DR participation.

Generator profit is not dramatically impacted by the participation of DR in the various electricity markets (Figure 2); in fact, in some cases, profits increase slightly. The reduction in consumer costs seen above, coupled with the fact that generator profits are not dramatically reduced, represents a Pareto improvement arising from the addition of DR. These results differ from previous work where the introduction of more flexible demand generally reduces the generator profits, see for example [30]. However, such results were calculated considering only operational decisions without including investment and exit decisions. In contrast, the work presented here determines equilibrium levels of capacity endogenously. Consequently, the introduction of DR decreases generator investment and increases capacity prices, offsetting the reduced electricity prices. When the impact of investment decisions is excluded however, DR does indeed reduce generator profits, which aligns with [30].

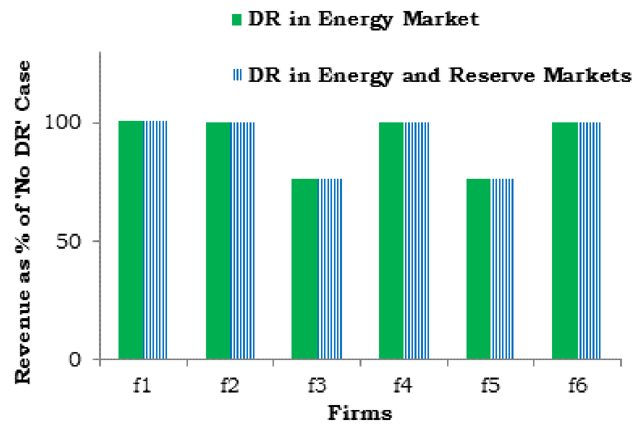

Fig. 2. Generator profit as a percentage of the 'No DR' case for different demand response market participation frameworks

TABLE VI
DEMAND RESPONSE AGGREGATOR COSTS AT A PEAK LOAD OF 2500 MW

DR Case	Energy Costs	Savings
No DR	€7,269,000	—
Energy Only	€6,993,000	4%
Energy & Reserve	€6,993,000	4%

D. Demand Response Aggregator Costs

Table VI shows the costs incurred by the DR aggregator, namely the costs of meeting the consumers' electricity requirements by purchasing electricity from the energy market. For the cases examined here, the aggregator's savings are 4% with the introduction of DR. This holds regardless of whether there is price-responsive demand, and so this saving is driven entirely by load shifting and is not as a result of any savings from a reduction in peak demand. Furthermore, varying marginal cost inputs and the generation portfolio induces no change in the aggregator's savings.

A well-known result from the literature is that savings on customers' electricity bills may not be sufficient to warrant investment in equipment and to compensate for the inconvenience associated with engaging in a DR program [31]. These results of a relatively low DR aggregator's savings are consistent with this finding. Furthermore, additional savings upon participation in the reserve market do not arise. This is because, as discussed previously, the reserve price was effectively zero at all times, as a result of the reserve requirement being automatically met by the capacity target.

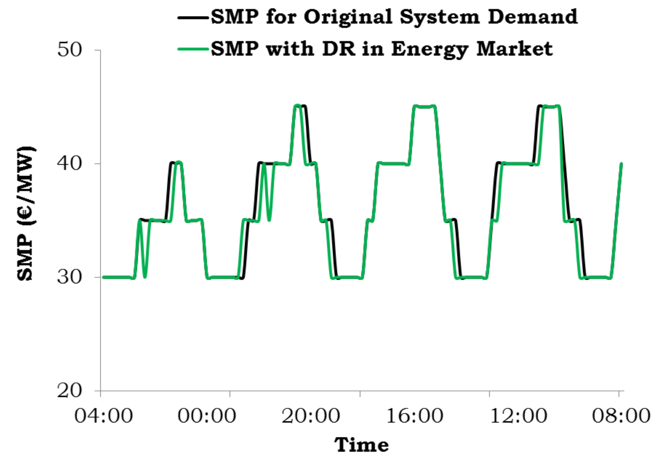

Fig. 3. Electricity price with and without DR for a peak load of 5000 MW

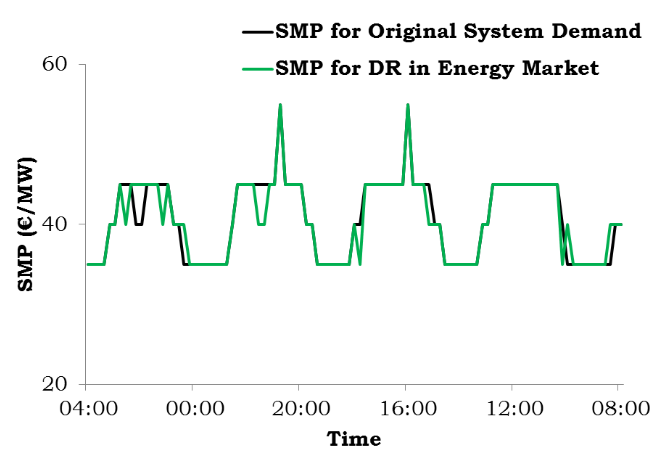

Fig. 4. Electricity price with and without DR for a peak load of 7500 MW

TABLE VII

CAPACITY PRICES, κ, FOR **7500 MW** OF PEAK LOAD AND WITH A RESERVE REQUIREMENT OF **500 MW**

		DR Participation		
Wind Level	E	No DR	Energy Only	Energy & Reserve
500 MW	0	€25	€25	€25
	−0.11	€25	€25	€25
1000 MW	0	€25	€25	€25
	−0.11	€25	€25	€25
1500 MW	0	€65	€1370	€1370
	−0.11	€110	€1402	€1402

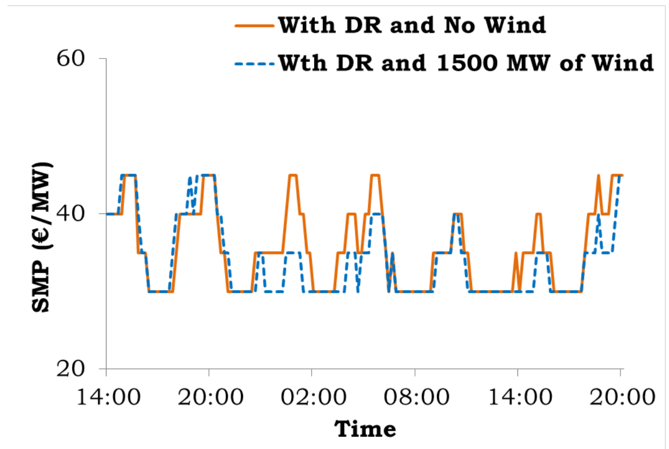

Fig. 5. System marginal price at a peak load of **7500 MW** with wind generation 20% of peak load

E. The interaction of DR, wind and peak load

1) Equilibrium prices and investment: Figures 3 and 4 compare the market price with and without DR participation for a system with a peak load of 5000MW and 7500MW respectively. As the DR capacity is fixed, this amounts to examining the impact of varying DR penetration. As expected, the impact of DR diminishes with increasing peak load.

In Table V above the capacity price was €3.35 or €7 depending on the scenario considered (with a peak load of 2500MW). At a peak load level of 5000 MW, the capacity price increases to €25 per MW for all scenarios and all wind levels examined, with and without DR. This is the maintenance cost of baseload units as baseload generation dominates the generating portfolio.

At a peak load level of 7500 MW, the capacity price remains at €25 per MW for all scenarios, except at a wind penetration of 1500 MW (Table VII). At this wind level, with no price-responsive demand and no load-shifting DR, the capacity price is €65, the marginal cost of the most expensive baseload unit on the system (Table III). However when price-responsive demand is introduced the capacity price increases, while the introduction of load-shifting DR induces a dramatic increase. This is driven by the suppression of the electricity price (Figure 5), as a result of high wind generation and DR participation. This suppression in electricity prices reduces generator profits in the energy market and consequently, the capacity market clears at a higher price to cover the firms' investment costs.

In spite of this increase in capacity prices, system operating costs do not increase drastically. This is primarily due to modelling firms as price-takers, and so surplus profits in the capacity market merely offset reduced revenues in the energy market.

2) Demand response aggregator costs: For peak demand of 2500MW, the aggregator's costs decrease as wind increases (see Table VIII). However this result does not hold at higher peak load levels. This is because increased wind, and the corresponding increase in variability of net demand, increases the opportunities for DR to earn revenues from the energy market, but also suppresses prices in the same market. The two effects offset each other and lead to a constant level of savings for the DR aggregator as wind generation increases at higher peak load levels. The extent to which the two effects offset each other, and the net result of increased wind generation, is system-specific.

Table VIII illustrates that there is essentially no change in the DR aggregator cost savings with price-responsive demand included, i.e. with $E = -0.11$. Thus the DR aggregator's savings are driven entirely by the load-shifting capabilities

TABLE VIII
DEMAND RESPONSE AGGREGATOR SAVINGS RELATIVE TO NO DR PARTICIPATION (E=0 AND E=-0.11)

	Wind	Peak load (MW) 2500	5000	7500
Energy Only	0MW	4%	9%	9%
Energy & Reserve		4%	9%	9%
Energy Only	500MW	4%	9%	9%
Energy & Reserve		4%	9%	9%
Energy Only	1000MW	4%	8%	9%
Energy & Reserve		5%	8%	9%
Energy Only	1500MW	8%	8%	9%
Energy & Reserve		8%	8%	9%

of the DR resource rather than consumer reduction in peak demand. In general, DR aggregator savings increase with increasing peak load.

V. DISCUSSION

There are several key insights that can be drawn from the results above. Firstly, DR participation in energy markets does succeed in reducing variability in electricity prices, whilst increasing prices at off-peak hours and decreasing peak prices. This induces significant system operating cost savings, mainly driven by the impact of the DR resource on the energy market. This result concurs with the literature, including literature which has focused on the operational effects of DR to date. What is interesting about the findings of this paper is that this effect is not confined to energy markets. Instead, DR participation leads to different equilibrium capacity prices and investments, in spite of the fact that DR does not participate in the capacity market. This is due to DR's impact on the conventional firms' energy profits. The resulting combination of energy and capacity market revenues for conventional generation means that there is minimal impact on generating firms' equilibrium profits. DR participation therefore reduces consumer costs but does not reduce generation firms' profits, which represents a Pareto improvement.

These positive impacts of DR participation in energy markets do not continue in the reserve market. This is due to the fact that the capacity target in this paper induces sufficient investment to allow firms to automatically meet the reserve requirements modelled here. Thus reserve prices are zero for nearly all hours considered. This result will hold for any market that includes a capacity margin that is greater than or equal to the reserve requirement. One could be tempted therefore to conclude that capacity and reserve can be considered as substitutes, as a capacity market automatically fulfils the role of a reserve market. However, this paper did not consider stochasticity, both in terms of wind generation and of forced outages of thermal generators. Including these uncertainties, which justify a non-zero capacity margin in the first place, may see higher reserve prices. In this case DR participation in the reserve market would change the equilibrium solution.

The impact of DR on equilibrium solutions is found to depend on the generation technology portfolio of the market in question, in particular the level of wind penetration. The fact that the impact of any given technology on equilibrium outcomes is dependant on the overall generation portfolio is a well-known result, and underlines the importance of studying entire generation portfolios rather than restricting focus to metrics such as the Levelised Cost of Electricity (LCOE) that consider each technology in isolation. In the particular case of DR, the equilibrium outcomes that are driven by DR's interaction with varying levels of wind arise from the fact that both technologies suppress prices in the energy market. Thus varying the level of wind penetration enhances DR's impact. This interaction of wind and DR suggests that the optimal DR penetration (and indeed, the optimal level of investment in any technology) is system-specific. It is likely that were DR to participate in capacity markets as well, yet another equilibrium would be reached. We leave the inclusion of DR in capacity markets for further work.

Sioshansi *et al.* [32] found that there were super-additive social surplus gains from DR in day-ahead energy markets only. We have also identified a similar effect that carries through our three-market framework. Energy prices are supressed, which leads to an increase in consumer surplus; however generator profits are not significantly impacted by this suppression of energy prices as the effect is offset by lower capacity investment costs. There is thus no change to producer surplus and the net effect is a welfare gain. Interestingly, at lower load levels/higher proportions of DR, there is an increase in the percentage reduction in system operating costs with increasing wind levels, but minimal change in generator profit. This effect mirrors that found by Siosanshi but makes it more explicit by identifying the equilibrium across all markets.

In this paper the firms maximised profits without considering the variability of same. However in reality firms generally exhibit risk-aversion, and so would instead maximise a risk-adjusted utility function. The results reported here, where DR reduces variability in electricity prices, suggest that DR can enhance the welfare of risk-averse producers by reducing risk as well as reducing electricity prices. Risk-averse consumers would also benefit from this reduction in uncertainty.

The capacity market equilibria reached in this paper can give some indication of the potential impact of DR participation in capacity markets. In the case of over-capacity, including DR in a capacity market would have little effect on the capacity price. This is because the capacity price would clear at a minimum of the level of marginal units maintenance costs, which in the case of DR is zero. In the case of under-capacity, capacity prices are determined by investment costs less any profits earned in energy and reserve markets. DR participation in the energy market will reduce energy prices and therefore reduce energy market profits for other firms. This will apply upward pressure to capacity prices. However, DR's own participation in the capacity market will provide downward pressure to capacity prices as DR has a negligible investment cost compared to the investment costs of conventional generators. Therefore the net effect of DR participation in capacity markets on equilibrium capacity prices is unknown as it depends on the relative magnitude of these effects. Future work will establish whether these hypotheses are true.

VI. Conclusion

This paper examined the participation of a load-shifting DR resource in energy and reserve markets. Several different models considering different DR market participation are developed. These markets are modelled as MCPs.

The results indicate that, in general, the DR resource can have a positive impact on electricity markets. However, this impact is largely limited to DR participation in the energy market. The interaction of wind generation and demand response does however induce changes in both energy and capacity markets, in spite of the fact that demand response does not participate in the capacity market. The resulting equilibrium represents a Pareto improvement relative to the case with no DR. The value of DR varies under different penetrations of DR and wind, suggesting that the optimal level of DR is system-specific.

Future research questions arising from this work include the substitutability of capacity and reserve markets, the welfare-enhancing capabilities of decreased variation in electricity prices, and the effect of stochastic variables. The results from this paper suggest that DR would have a positive impact when these considerations are taken into account.

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