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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 and gives rise to lower equilibrium levels of investment in conventional generation. DR and wind generation are strongly complementary, due to the ability of DR to mitigate against the variability of wind generation, with the highest reduction of consumer costs seen at high levels of wind penetration. The total impact of DR is highly dependent on specific system characteristics.

*Keywords:* Demand Response, Load-Shifting, Markets, Reserve

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## 1. 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 (Strbac, 2008; Zhou et al., 2015; Ma et al., 2013; Sioshansi and Short, 2009; Kirby, 2006; Torbaghan et al., 2018). 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 (Kirby, 2007b; Kirby et al., 2008; Callaway, 2009; Ma et al., 2013), which we define as services that the system operator employs over various time-frames to maintain the supply-demand balance on a continuous basis (Kirby, 2007a). Recent research also shows that DR can contribute to capacity markets (Zhou et al., 2015; Nolan and O'Malley, 2015)

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

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markets simultaneously. The importance of valuing DR correctly was highlighted in Nolan and O'Malley (2015).

The focus of 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 (Ventosa et al., 2000; Bushnell, 2003), reserve markets Liang et al. (2011) and capacity markets (Höschle et al., 2015; Khal-fallah, 2009; Lynch and Devine, 2017).

In recent years MCPs have been used to examine price-responsive demand. Daoxin et al. (2012) 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 Kirschen et al. (2012); Dietrich et al. (2012) rather than MCPs. In the first case study in Kirschen et al. (2012), 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 Kirschen et al. (2012), hourly demand and wind data is utilized and DR is assumed to be 5% of the system load in each hour.

Conejo et al. (2010) propose an hourly real-time DR model. The demand model minimizes the cost of meeting the load minus the utility of the customers. Unlike Daoxin et al. (2012), Conejo et al. (2010) 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. (2015) 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. Similarly, Nunna et al. (2016) only consider an energy market when they use an agent based approach to model an energy management system for smart microgrids. Brijs et al. (2016) 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.

De Jonghe et al. (2012) 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 (De Jonghe et al., 2012) 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 De Jonghe et al. (2012), while this paper models a load-shifting DR resource based on electrical space and water heating demand data, which includes the ability to provide reserve and an energy limit constraint. 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. This is a data contribution of the current work. While the model gives a realistic representation of this specific DR resource, it can be adapted for different DR resources.

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 as well as optimal operational decisions by all parties. 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 data and methodological contributions enable us to consider the impact of DR participation in both energy and reserve markets.

The use of MCPs in this paper precludes the use of integer variables, and so the models presented here do not include complex operational variables and constraints such as start costs and no load costs. Thus the modelling of the markets here is not a realistic representation of detailed power system operation and likely underestimates the importance of the reserve market in particular. Nonetheless, there are some valuable insights that can be gained regarding market equilibria and the potential for DR to influence same.

The paper proceeds as follows: Section 2 introduces the MCP methodology employed including the DR aggregator problem. Input data and case study information is discussed in Section 3. Section 4 presents the results and sensitivities, Section 5 discusses the key findings and Section 6 concludes.

## 2. Methodology

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

### 2.1. Demand Response Aggregator’s Problem

We model one DR aggregator whose problem is to maximise profits from energy and reserve markets. To do so, they choose how to shift consumers’ demand in both the downward and upward direction ( $dr_{down}^t$  and

$dr_{up}^t$  respectively) and reserve provision ( $reserve_{dr}^t$ ). 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  $dr_{down}^t$  and  $dr_{up}^t$ , the upwards and downwards change from the reference demand at each time,  $t$ .

The parameter  $DMAX$  represents the total installed capacity of the DR resource. Equation (1) 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 (2) 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. Equation (3) denotes the reserve component of the DR aggregator's profit. Equation (4) ensures that, in each time-step,  $t$ , the DR aggregator can only shift downwards and can only provide upward reserve 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 (5) constrains the upward shifting of the resource to be less than the installed capacity of the end-user appliance,  $DMAX$ . Equation (6) 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:

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

where

$$\Pi_{energy} = \sum_t (dr_{down}^t - dr_{up}^t - DREF^t) \times \lambda^t, \quad (2)$$

$$\Pi_{reserve} = \sum_t (reserve_{dr}^t) \times \mu^t, \quad (3)$$

subject to:

$$dr_{down}^t + reserve_{DR}^t \leq DREF^t, \quad (\gamma_1^t), \quad \forall t, \quad (4)$$

$$dr_{up}^t + DREF^t \leq DMAX, \quad (\gamma_2^t), \quad \forall t, \quad (5)$$

$$\sum_{t=t'}^{t'+23} (dr_{down}^t) = \sum_{t=t'}^{t'+23} (dr_{up}^t), \quad (\gamma_3^{t'}), \quad \forall t' \in \{1, 25, 49, \dots\}, \quad (6)$$

This is easily achieved by varying the values of the parameters relating the maximum installed capacity and the reference demand. Appendix A provides the DR aggregator's Karush-Kuhn-Tucker (KKT) conditions for optimality.

## 2.2. Generating Firm's Problem

We model a number of generating firms. Firm  $i$ 's problem is to maximise profits,  $\Pi_{gen}^i$ , which they earn in energy, reserve and capacity markets,  $\Pi_{energy}^i$ ,  $\Pi_{reserve}^i$  and  $\Pi_{capacity}^i$ , 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.

Firms choose the amount of generation ( $gen^{t,i,j}$ ), reserve provision ( $reserve_{gen}^{t,i,j}$ ) and their capacity bid ( $cap_{bid}^{i,j}$ ) 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.

Firm  $i$ 's objective function is Equation (7). Each generating firm chooses their profit-maximising participation in each market simultaneously. Equation (8) 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 (9) denotes the generator's reserve market profit. Equation (10) represents the profit from the capacity market less investment and maintenance costs associated with capacity provision. Equation (11) constrains the power and reserve provided by a generating unit to be less than or equal to their installed capacity. Equation (12) ensures each generator's capacity bid does not exceed its installed capacity.

The parameter  $ICOST^j$  represents the investment cost (per MW) of generating technology  $j$ , while  $MCOST^j$  is the maintenance cost (per MW) 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:

$$\max_{\substack{gen \\ exit \\ invest \\ cap}} \Pi^i = \sum_j \Pi_{energy}^{i,j} + \sum_j \Pi_{reserve}^{i,j} + \sum_j \Pi_{capacity}^{i,j}, \quad (7)$$

where

$$\Pi_{energy}^{i,j} = \sum_t (gen^{t,i,j}) \times (\lambda^t - MC^{i,j}), \quad (8)$$

$$\Pi_{reserve}^{i,j} = \sum_t (reserve_{gen}^{t,i,j}) \times \mu^t, \quad (9)$$

$$\Pi_{capacity}^{i,j} = (cap_{bid}^{i,j}) \times (\kappa) - (invest^{i,j}) \times ICOST^j - (CAP^{i,j} - exit^{i,j}) \times MCOST^j, \quad (10)$$

subject to:

$$gen^{t,i,j} + reserve_{gen}^{t,i,j} \leq CAP^{i,j} - exit^{i,j} + invest^{i,j}, \quad (\theta_1^{t,j}), \quad \forall t, j, \quad (11)$$

$$cap_{bid}^{i,j} \leq CAP^{i,j} - exit^{i,j} + invest^{i,j}, \quad (\theta_2^{i,j}), \quad \forall t, j, \quad (12)$$

The variables  $\lambda_t$ ,  $\mu_t$  and  $\kappa$  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 (decision) variables are constrained to be non-negative. Appendix B provides the firms' KKT conditions for optimality.

The firms' decision variables are all continuous and thus operational constraints that require integer variables are not considered. In particular, start costs, no load costs and ramping constraints are not modelled here and the units are scheduled on the basis of price-quantity bids. Thus the modelling here is a good approximation of most European power markets (which, in general, do not include these operational constraints) but is not a realistic representation of detailed system operation, nor is it intended to be so. The main consequence of this simplification is that the model presented here underestimates the activity and importance of the reserve market, which mitigates the effects of the discrepancy between the power market schedule and the actual operation of the units on the system. In order to partially compensate for this simplifying assumption, we run the model under varying reserve requirements.

Wind is incorporated into the model via the energy Market Clearing Conditions (equations (13) and (14) below). It is not owned by any generation firm and its sole function is to reduce net demand and it does not participate in either the reserve or the capacity market. This is because wind has a marginal cost of zero and furthermore can only be dispatched downwards, and so given an exogenously-determined level of wind capacity, wind generation itself is unlikely to ever be strategically withheld by a generation firm. Given that wind capacity in Ireland, like most European countries, is driven primarily by government targets rather than market outcomes, an exogenously-determined level of wind capacity is not unrealistic, and thus including wind output itself as a strategic variable would serve only to increase the size of the problem without any corresponding change in the results.

### 2.3. Market Clearing Conditions

The market clearing conditions vary depending on the scenario under investigation. The first market clearing condition (13) models the energy market when DR is not considered:

$$\sum_{i,j} gen^{t,i,j} = DEM^t - WIND^t + E \times \lambda^t, \quad \forall t, \quad (\lambda^t), \quad (13)$$

where the parameters  $DEM^t$  and  $WIND^t$  denote the demand intercept and wind power level in hour  $t$ , respectively. The parameter  $E$  represents the slope of the demand curve, and so this market clearing condition

Table 1: MCP models considered

| <b>DR<br/>Participation</b> | <b>Model</b> |          |          |
|-----------------------------|--------------|----------|----------|
|                             | <b>1</b>     | <b>2</b> | <b>3</b> |
| Energy                      | —            | ✓        | ✓        |
| Reserve                     | —            | —        | ✓        |

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 (13) becomes:

$$\sum_{i,j} gen^{t,i,j} = DEM^t - WIND^t - DREF^t + dr_{up}^t - dr_{down}^t + E \times \lambda^t \quad \forall t, \quad (\lambda^t). \quad (14)$$

The market clearing conditions for the reserve market, with (15) and without (16) DR participation, are:

$$\sum_{i,j} reserve_{gen}^{t,i,j} + reserve_{DR}^t = RESERVE_{REQ} \quad \forall t, \quad (\mu^t), \quad (15)$$

$$\sum_{i,j} reserve_{gen}^{t,i,j} = RESERVE_{REQ} \quad \forall t, \quad (\mu^t), \quad (16)$$

where the parameter  $RESERVE_{REQ}$  is the total reserve required. The market clearing condition for the capacity market, in which DR does not participate, is

$$\sum_i cap_{bid}^i = TARGET, \quad (\kappa), \quad (17)$$

where 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 (Ferris and Munson, 2000). The market clearing conditions are utilized in conjunction with the firms' and the DR aggregator's KKT conditions, in different combinations, to produce a number of different MCP models. The models in Table 1 model DR participation in various combinations of markets. In each case, conventional generation firms participate in energy, reserve and capacity markets. The models are run both with and without price-responsive demand.

As each of the individual players' optimisation problems are linear, any solution found by a MCP is guaranteed to be optimal for each actor, thus representing a Nash-equilibrium. However, there may be multiple Nash-equilibria as any solution provided by the MCP may be non-unique.

Table 2: Initial endowment of capacity  $CAP^{i,j}$  for each firm and technology type (MW)

|           | f1   | f2   | f3   | f4  | f5   | f6  | Sum  |
|-----------|------|------|------|-----|------|-----|------|
| Baseload  | 1000 | 800  | 500  | 500 | 400  | —   | 3200 |
| Mid-merit | —    | 500  | 400  | —   | 400  | —   | 1300 |
| Peaking   | —    | —    | 200  | 300 | 200  | 200 | 900  |
|           | 1000 | 1300 | 1100 | 800 | 1000 | 200 | 5400 |

Table 3: Marginal cost of each firm (€/MW)

|           | f1 | f2 | f3 | f4 | f5 | f6 |
|-----------|----|----|----|----|----|----|
| Baseload  | 30 | 45 | 55 | 55 | 65 | —  |
| Mid-merit | —  | 50 | 35 | —  | 35 | —  |
| Peaking   | —  | —  | 93 | 83 | 93 | 93 |

### 3. Input Data

#### 3.1. System Data

The models are run in a stylised electricity market with six conventional generation firms (f1 - f6) and a single DR aggregator. The initial endowment of capacity for each firm  $CAP^{i,j}$  is shown in Table 2 and the corresponding cost characteristics are presented in Tables 3 and 4. The costs data are all based on the values employed in Lynch and Devine (2017) with some variation between the marginal costs for each unit within each technology group.

Small levels of storage exist on the Irish system, but these were not considered in this analysis in order to isolate the effects of DR in particular. It should be noted that storage and DR have similar characteristics and so can be considered substitutes, and so increased storage may dampen the effects of DR (and vice versa).

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 (Doherty and O'Malley, 2005). The capacity target,  $TARGET$ , is 1.2 times the system peak load. This is in keeping with the method of determining the capacity target on the Irish system. The non-zero capacity margin is determined by the system operator and takes account of exogenous parameters including forced outage rates

Table 4: Investment and annual maintenance costs (€/MW)

|           | $MCOST^j$ | $ICOST^j$ |
|-----------|-----------|-----------|
| Baseload  | 25        | 100000    |
| Mid-merit | 12        | 65000     |
| Peaking   | 7         | 45000     |

and variability in renewable generation and in demand.

All players are assumed to be price-takers. This assumption is a strong one in general, but for the Irish market is not unrealistic as generators' bids are subject to strong regulation, whereby they must submit energy bids that truthfully reflect their true costs of generating. Empirical studies have verified that generators have indeed complied with this requirement (O'Mahoney and Denny, 2013; Di Cosmo and Valeri, 2018). Inclusion of market power when considering several markets concurrently (energy, capacity and reserve) is non-trivial but future work will consider this question.

### 3.2. Demand and wind data

The consumer end-use heating time series obtained by the methodology in Neu et al. (2014) 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 (SEMO, 2011) is scaled linearly three times to produce three time series for the demand intercept parameter  $DEM^t$ ; firstly to ensure a peak load of 2500MW, secondly to ensure to a peak load of 5000MW, and finally to ensure to a peak load of 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. It is important to note that  $DEM^t$  does not represent system demand, as outputted by the model. Outputted system demand at hours  $t$  is represented by  $\sum_{i,j} gen^{t,i,j} + WIND^t$ . While these outputted demand values are unlikely to match those actually observed in 2009, using actual demand data to populate to demand curve intercept values allows us to capture actual daily variation in system demand. The slope of the demand curve ( $E$ ) is set at  $-0.11$  as determined by Cosmo and Hyland (2013).

The analysis is performed for the first 100 days of the year, which covers the winter peak demand. We choose 100 days instead of 365 days to reduce the computational burden of the MCPs being solved. Furthermore we believe that modelling all 365 days of the year would lead to similar results as the first 100 days of the year contains the winter peak demand and thus sufficiently captures the impact of capacity constraints. Wind capacity factors are determined based on historical Irish wind data, also from 2009.

## 4. Results

### 4.1. 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 ( $\mu^t$ ) 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

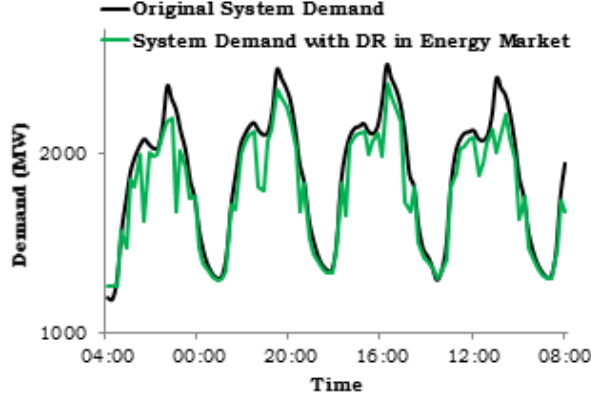


Figure 1: System demand with the addition of demand response over a four day period for a peak load of 2500 MW with no wind generation ( $E=-0.11$ )

Table 5: Capacity prices,  $\kappa$ , for 2500 MW of peak load and no wind

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

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,  $\mu^t$ , 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 5 displays the capacity price,  $\kappa$ , 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 €3.35 to €7 per MW. This is because DR reduces peak energy prices and thus a higher capacity price is needed to compensate firms. Similarly, when demand becomes price responsive, and there's no DR, the capacity price also increases from €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.

#### 4.2. Consumer Costs

In determining consumer costs, Equation (18) is used for the models without DR, while Equation (19) 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.

$$Cost_{NoDR} = \sum_{t,i,j} (Gen^{t,i,j} \times \lambda^t + reserve_{Gen}^{t,i,j} \times \mu^t) + \sum_{i,j} (Cap_{Bid}^{i,j}) \times \kappa + WIND^t \times \lambda^t \quad (18)$$

$$Cost_{DR} = \sum_{t,i,j} (Gen^{t,i,j} \times \lambda^t + reserve_{Gen}^{t,i,j} \times \mu^t) + \sum_{i,j} (Cap_{Bid}^{i,j}) \times \kappa + \sum_t (reserve_{DR}^t \times \mu^t) + WIND^t \times \lambda^t \quad (19)$$

When peak load is 2500MW and there is 0MW of wind generation, DR induces a 6% reduction in consumer costs whether or not there is price-responsive demand. This result concurs with Su and Kirschen (2009). 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 (Nolan and OMalley, 2015).

#### 4.3. Generator Profit

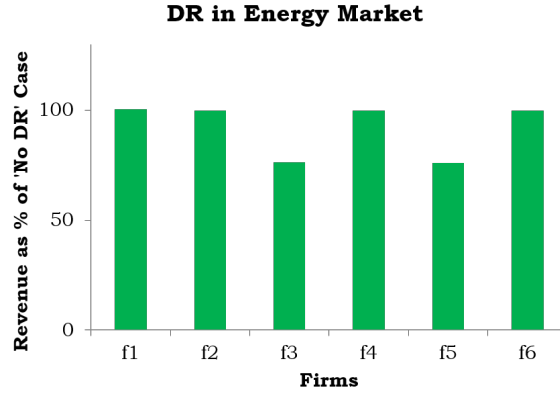


Figure 2: Generator profit as a percentage of the ‘No DR’ case for different demand response market participation frameworks for a peak load of 2500 MW with no wind generation ( $E = -0.11$ )

Figure 2 shows the firms’ profits when DR participants in the energy market only, relative to no DR participation. The same results were observed were DR participants in both the energy and reserve markets. The inclusion of DR does not drastically affect the profits of firms 1, 2, 4 and 6. However, it does reduce the profits of firms 3 and 5. This is because these two firms both hold a mid-merit unit with marginal cost of €35 and these two units are typically the marginal generating units. Thus, firm 3 and 5 lose out to reduced energy prices when DR is introduced as their mid-merit units are not required to generate. Moreover, as Table 5 shows, the inclusion of DR does significantly not increase capacity prices in this case. This is in contrast to cases where peak load is relatively higher (Section 4.5), where the inclusion of DR does increase

Table 6: Demand response aggregator costs at a peak load of 2500 MW and no wind ( $E = 0$ ).

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

capacity prices and hence, reduced generator profits in the energy market are offset by increased profits in the capacity market.

#### 4.3.1. Increasing the Reserve Requirement

We now consider the impact of increasing the reserve requirement from 500MW to 1500MW. At the lower peak load levels of 2500MW and 5000MW, the higher reserve requirement impacts upon both the reserve price (at the peak hour only) and on the capacity price as the reserve market constraint becomes binding. Consequently, the more stringent reserve requirement dominates investment decisions, i.e., firms invest to meet the reserve requirement, not the capacity target. This results in capacity prices of €0 for all cases, while the reserve price is extremely low at all hours, except at the peak hour where the reserve price is €25.

At the highest load level, 7500 MW, there is, initially, considerable under-capacity. Thus, increasing the reserve requirement to 1500 MW has no impact on the reserve price, which remains at €0, as the generating firms are continuing to invest in order to meet the capacity target.

#### 4.4. Demand Response Aggregator Costs

Table 6 displays the costs incurred by the DR aggregator, namely the costs of meeting the consumers' electricity requirements by purchasing electricity from the energy market. It shows that 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 the model marginal costs and the generation portfolio, produces similar results in terms of the aggregator's savings, suggesting this result is robust to changes in these parameters.

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 (Boisvert and Neenan, 2003). The relatively low (4%) DR aggregator's savings in Table 6 are consistent with this finding.

#### 4.5. The interaction of DR, wind and peak load

##### 4.5.1. 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 (no wind generation). As the DR capacity is fixed, this examines

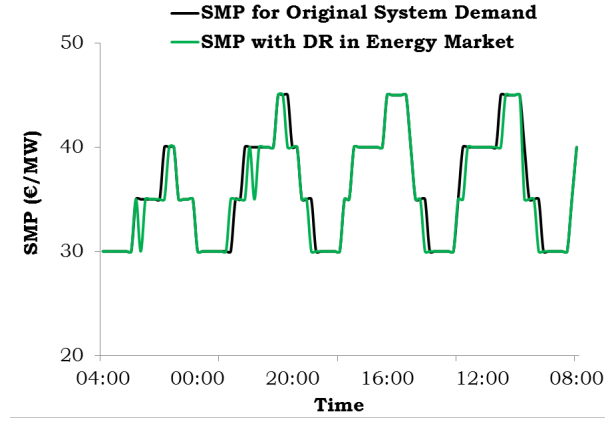


Figure 3: System Marginal Price (SMP) with and without DR for a peak load of 5000 MW and no wind

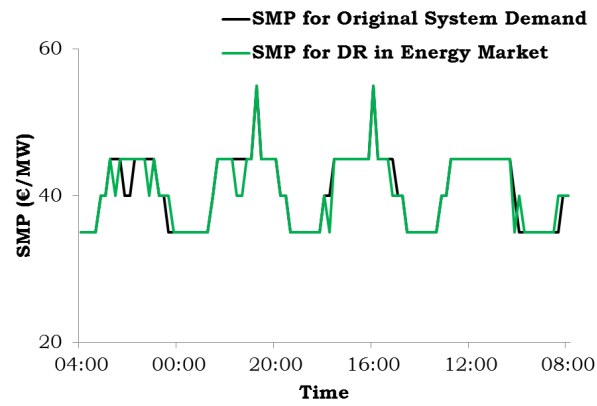


Figure 4: System Marginal Price (SMP) with and without DR for a peak load of 7500 MW and no wind

the impact of varying DR penetration. As expected, the impact of DR diminishes with increasing peak load as DR becomes a smaller proportion of peak load.

In Table 5, 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 7). 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 3). 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.

Table 7: Capacity prices,  $\kappa$ , for **7500 MW** of peak load

| Wind<br>Level | E     | DR Participation |                |                     |
|---------------|-------|------------------|----------------|---------------------|
|               |       | No<br>DR         | Energy<br>Only | Energy &<br>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               |

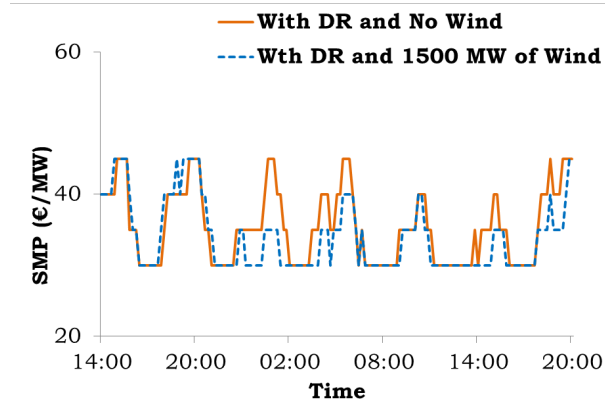


Figure 5: System marginal price at a peak load of 7500 MW and 1500 MW of wind generation.

Table 8: Demand response aggregator cost savings relative to no DR participation (energy market only)

|             |        | Peak load (MW) |      |      |
|-------------|--------|----------------|------|------|
| Wind        |        | 2500           | 5000 | 7500 |
| $E = 0$     | 0MW    | 4%             | 9%   | 9%   |
| $E = -0.11$ |        | 4%             | 9%   | 9%   |
| $E = 0$     | 500MW  | 4%             | 9%   | 9%   |
| $E = -0.11$ |        | 4%             | 9%   | 9%   |
| $E = 0$     | 1000MW | 4%             | 8%   | 9%   |
| $E = -0.11$ |        | 5%             | 8%   | 9%   |
| $E = 0$     | 1500MW | 8%             | 8%   | 9%   |
| $E = -0.11$ |        | 8%             | 8%   | 9%   |

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.

#### 4.5.2. Demand response aggregator costs

For peak demand of 2500MW, the aggregator's costs savings increase as wind increases (see Table 8). 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 an almost 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 8 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 of the DR resource rather than consumer reduction in peak demand. In general, DR aggregator savings increase with increasing peak load. While Table 8 displays the savings when DR is only included in the energy market, we observed the same results when DR was included in the energy and reserve markets.

#### 4.5.3. Generator Profit

Figure 6 displays the firms' profits when DR participants in the energy market only, relative to no DR participation. The same results were observed were DR participants in both the energy and reserve markets. In contrast to Figure 2, generator profit is not dramatically impacted by the participation of DR in the various electricity markets; in fact, in some cases, profits increase slightly. This is because the reduced generator profits in the energy market are offset by increased profits in the capacity market. The reduction in consumer

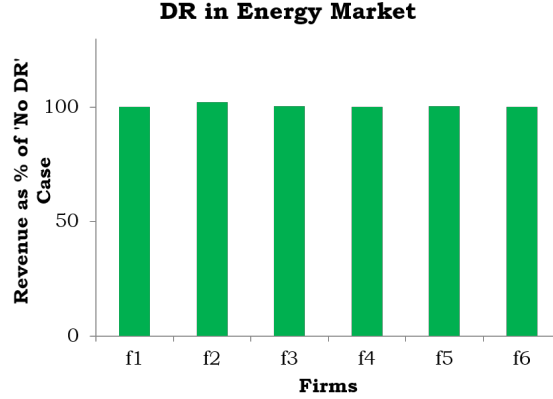


Figure 6: Generator profit as a percentage of the ‘No DR’ case for different demand response market participation frameworks for a peak load of 7500MW.

costs seen in Table 8, coupled with the fact that generator profits are not dramatically reduced, means that DR as modelled here improves outcomes for both consumers and producers. These results differ from previous work where the introduction of more flexible demand generally reduces the generator profits, see for example Su (2007). 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 Su (2007).

## 5. 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 savings in system operating cost, 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.

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 fulfills the role of a reserve market. However, it is important to bear in mind, as noted above, that the MCP model used in this work did not consider binary variables typically seen in unit commitment models. Including binary variables in MCPs is only an emerging area of operations research with solution methods currently being developed (Gabriel, 2017). Given that electricity markets across Europe do not include start costs and no load costs in the units' bids, the inclusion of such variables would not significantly change the energy market outcomes, but would have an impact on the reserve market, as units may find themselves faced with a technically infeasible production schedule, necessitating reserve market sales or purchases. Furthermore, we did not consider stochasticity, in terms of electricity demand, wind generation and forced outages of thermal generators. Including these model complexities, which justify a non-zero capacity margin in the first place, would lead to higher reserve prices and is something we will leave to future work. 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 complements 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.

Sioshansi (2010) 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 methodology. Energy prices are suppressed, 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 Sioshansi but makes it more explicit by identifying the equilibrium across all markets.

If DR were to participate in capacity markets, it is likely equilibria other than those found in this work would be reached. We leave the inclusion of DR in capacity markets for further work. However, 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. As discussed above,

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, i.e., system specifics. Future work will establish whether these hypotheses are true.

## 6. 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, in the model considered here. 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. However, 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 and binary 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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## Appendix A. KKT conditions for DR providing energy and reserve

The KKT conditions for the DR aggregator are shown below.

$$0 \leq dr_{down}^t \perp -\lambda^t + \gamma_1^t + \gamma_3^{t'} \geq 0, \quad \forall t, t' \in H, \quad (\text{A.1})$$

$$0 \leq dr_{up}^t \perp \lambda^t + \gamma_2^t - \gamma_3^{t'} \geq 0, \quad \forall t, t' \in H, \quad (\text{A.2})$$

$$0 \leq \text{reserve}_{DR}^t \perp -\mu^t + \gamma_1 \geq 0, \forall t, \quad (\text{A.3})$$

$$0 \leq \gamma_1^t \perp DREF^t - dr_{down}^t - \text{reserve}_{DR}^t \geq 0, \forall t, \quad (\text{A.4})$$

$$0 \leq \gamma_2^t \perp DMAX - dr_{up}^t - DREF^t \geq 0, \forall t, \quad (\text{A.5})$$

$$0 = \sum_{t=t'}^{t'+23} (dr_{down}^t) - \sum_{t=t'}^{t'+23} (dr_{up}^t), \quad \gamma_3^{t'} \text{ free}, \quad \forall t' \in H, \quad (\text{A.6})$$

As above, the KKT conditions are both necessary and sufficient for optimality.

## Appendix B. KKT conditions for firm providing energy, reserve and capacity

The KKT conditions for all firms are given below:

$$0 \leq \text{gen}^{t,i,j} \perp -\lambda^t + \theta_1^{t,i,j} + MC^{i,j} \geq 0, \forall t, i, j, \quad (\text{B.1})$$

$$0 \leq \text{reserve}_{Gen}^{t,i,j} \perp -\mu^t + \theta_1^{t,i,j} \geq 0, \forall t, i, j, \quad (\text{B.2})$$

$$0 \leq \text{cap}_{bid}^{i,j} \perp -\kappa + \theta_2^{i,j} \geq 0, \forall t, i, j, \quad (\text{B.3})$$

$$0 \leq \text{invest}^{t,i,j} \perp ICOST_{i,j} - \sum_t \theta_1^{t,i,j} - \theta_2^{i,j} \geq 0, \forall t, i, j, \quad (\text{B.4})$$

$$0 \leq \text{exit}^{t,i,j} \perp -MCOST_{i,j} + \sum_t \theta_1^{t,i,j} + \theta_2^{i,j} \geq 0, \forall t, i, j, \quad (\text{B.5})$$

$$0 \leq \theta_1^{t,i,j} \perp CAP_{i,j} - \text{exit}^{t,i,j} + \text{invest}^{t,i,j} - \text{gen}^{t,i,j} - \text{reserve}_{Gen}^{t,i,j} \geq 0, \forall t, i, j, \quad (\text{B.6})$$

$$0 \leq \theta_2^{i,j} \perp CAP_{i,j} - \text{exit}^{t,i,j} + \text{invest}^{t,i,j} - \text{cap}_{bid}^{i,j} \geq 0, \forall t, i, j. \quad (\text{B.7})$$

As firm  $i$ 's problem is convex, the KKT conditions are both necessary and sufficient for optimality.

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