Balancing variable supply with flexible demand

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Keywords

smart grid, demand side management (DSM), renewable energy, electric vehicles

Abstract

The UK electricity system is undergoing a significant transformation. On the supply side, the increasing penetration of renewable energy resources raises concerns for grid stability due to their intermittency. On the demand side, transportation and heating electrification, as well as small scale electricity generators, are making demand side more unpredictable. This challenges the traditional way of balancing electricity in the grid, whereby supply matches demand.

Demand-side management (DSM) can offer a promising solution to the above problems by coordinating electricity consumption with variable supply from renewable resources. However, considering the number of autonomous stakeholders involved, each with their different objectives, it is uncertain how such coordination will be performed. Traditionally, in the UK the system operator is responsible for balancing the grid in a centralised manner. However, centralised coordination raises privacy and scalability concerns (processing a large amount of information in real-time). Decentralised coordination methods offer a way for consumers to retain information privacy and have been shown to work well in a simulation environment whereby a single aggregator controls a pool of identical consumers. This work explores the value of such decentralised coordination methods in the context of the interacting and evolving electricity system in the UK.

The first part of the paper investigates the impact of integrating storage into the UK electricity system. We use National Grid future energy scenarios (FES) to allocate electrical storage capacity to consumer sectors (domestic, commercial and industrial) and the system (referring to pump storage). We explore the benefits and trade-offs of central versus distributed coordination strategies of consumer and system storage for the period of 2015–2050 in accordance with FES. We find that the long-term benefits are higher in the case of centralised balancing however consumers do not benefit equally.

The second part of the paper investigates how the introduction of DSM into the supply electricity market can serve as a tool for utilities in gaining a competitive advantage. Two types of suppliers were considered: a traditional vertically integrated one (with dispatchable power generator) and a green supplier (in possession of renewable generation technology). The modelling was able to show that with enough dispatchable capacity or flexible resources, the traditional supplier profited from increasing demand peaks in the system. In order to compete, the green supplier was obliged to perform demand flattening coordination.

Introduction

Climate change policies amongst other triggers such as lowering costs for ICT and improved storage and micro generation technology are driving changes within the UK power system. On the supply side, the UK has seen a significant growth in the deployment of renewable power generators over the last decade, in particular wind and solar. Since 2002, annual energy generated from wind has grown from 720 GWh to 36,153 GWh (REF, 2016).

On the demand side, a number of technologies have been entering the market, such as small scale batteries, electric vehicles, electric heat pumps and microgeneration units (particularly rooftop solar PV). In 2015, small scale solar PV (<4 kW) installations accounted for 25 % of the total solar PV capacity in the UK (REF, 2016), whilst the number of plug-in electric vehicles has reached 47,000 by 2015 with a high growth rate (DfT, 2015). In addition to this, consumers are becoming more active due to proliferation of smart power metering and management technology (Smart Energy GB, 2016). This is particularly true for commercial and industrial sectors. Nevertheless, the domestic sector is expected to catch up as a result of government plans to integrate smart meters in all households by 2020 (DECC, 2013). The changes on the supply and demand sides of the electricity system are causing concern for the grid, as it becomes more difficult to coordinate variable supply with unpredictable demand.

Demand side management (DSM) can offer a promising solution to balancing the electricity grid. Certain technologies like electric vehicles and electrical or heat storage can be scheduled to operate during times of high renewable supply when electricity prices and emissions are low. Industrial players of the electricity markets are recognizing the potential of DSM and the new business opportunities associated with an increasing demand for clean energy. DSR schemes aimed at commercial and industrial consumers are already being deployed on a commercial scale on the basis of direct load control (DLC). Companies such as Flexitricity and KiWi offer their client a fee in exchange for the ability to control a proportion of their load. DSR schemes in the domestic sector so far aim to influence consumer behaviour indirectly through time varying electricity tariffs, e.g. time-of-use (TOU) or critical-peak-pricing (CPP), whereas domestic DLC programmes extend only as far as pilot schemes.

The UK electricity system has a complex configuration as well as multiple stakeholders, each with their own objectives which makes the coordination problem a complicated issue. This work will examine the potential issues that may arise at the physical and the market layers of the UK electricity system as a result of the deployment of demand side coordination.

THE PHYSICAL LAYER

Figure 1 shows a simplified configuration of the UK electricity grid. It can be seen that electricity consumption and generation takes place at multiple voltage levels. Hence balancing the demand at bottom level (we refer to this type of coordination as **distributed**) may not necessarily mean a smooth global demand. On the other hand, balancing the demand from the top (**centralised** coordination) may not mean optimal performance for the consumers as it might conflict with their objectives.

We pose the following questions:

1. What is better **distributed** or **centralised** coordination and for whom?
2. What is the value of storage in the future UK electricity system taking into account the different balancing scenarios?

THE MARKET LAYER

The electricity is bought and sold in the wholesale and retail markets in the UK. The changes on the supply and demand sides are encouraging the appearance of new types of electricity supplier – those who can invest into cleaner smarter energy. Since 2011, the share of independent utilities[1] in the country has grown from 1 % to 15 % for domestic electricity (ofgem, 2016). The new independent suppliers (e.g. Ecotricity and Good Energy) are giving consumers the option to purchase 100 % 'green' electricity, harnessed from their own renewable generators. Other incentives include free electric vehicle charging at supplier-owned charging points and receiving payments for domestically generated electricity[2].

However, whereas the green utilities are able to offer the consumer cleaner power, they still have to go to the market to purchase additional electricity. Hence, it is uncertain how the two types of supplier companies will compete in the future electricity market.

This paper aims to answer the following questions:

1. How could DSM influence future business models of electricity utilities?
2. Can DSM be disruptive? Can utilities use it to gain a competitive advantage while compromising global sustainability goals?

Relevant work

The idea of using demand side flexibility to compensate for intermittent supply is not new (e.g. Schweppe, Daryanian, & Tabors, 1989). However, due to the lack of communication technology the work remained preliminary and thus untested in simulation settings.

Recent developments in communication and data management tools (smart meters, mobile internet, cloud computing) alongside rapid integration of renewables have reignited academic interest in demand-side control as a means to compensate for variable supply. The 'new' demand side management (DSM) models assume the presence of software agents, which are responsible for the operation of an electrical device (e.g. electric vehicle, air conditioning or a washing machine) **and** can optimise electricity consumption on behalf of the consumer. Compared to traditional DSM[3] schemes aimed at human behaviour, software agents are able to perform complex calculations faster using tools such as machine learning, robust and stochastic optimisation.

There is a large body of research focusing on different ways of performing DSM. A good overview of existing methods is given in (Boßmann & Eser, 2016; W. Yang & Yu, 2014; Z. Yang, Li, Foley, & Zhang, 2014). A major shortcoming of these models is that the system under consideration often represents an idealistic setting where a set of homogeneous consumers are being coordinated by a single aggregator. For example, in (Voice, Vytelingum, Ramchurn, Rogers, & Jennings, 2011) the authors consider a set of identical residential consumers whose demand profile is being scheduled by a single aggregator. A similar example, (Gan, Topcu, & Low, 2013)

1. Not the The Big Six (British Gas, EDF Energy, E.ON UK, npower, ScottishPower and SSE).

2. Please visit https://www.ecotricity.co.uk/; https://goodenergy.co.uk/; https://tempusenergy.com/.

3. Sometime also referred to as demand side response (DSR)

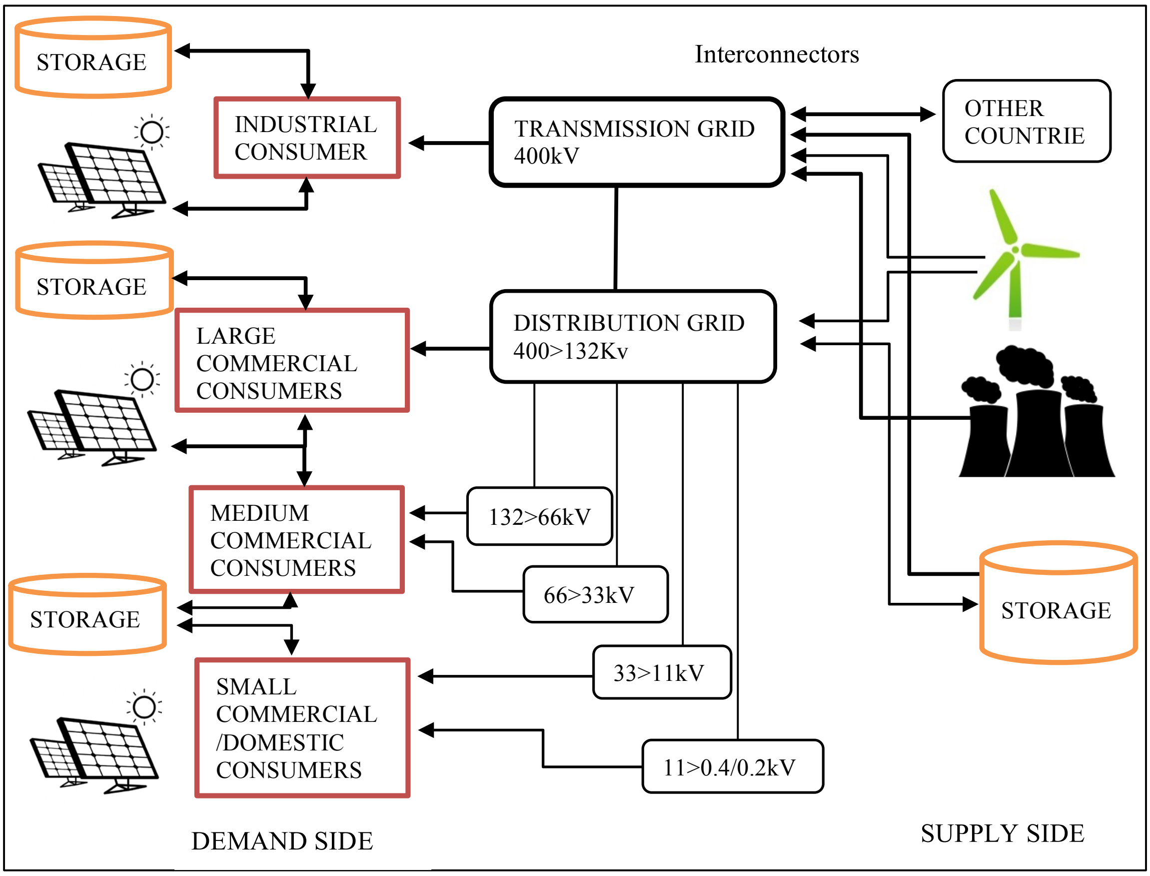

Figure 1. Graphical representation of the electricity flow in the GB electricity grid.

considers a system where one supplier coordinates identical consumers in possession of electric vehicles. On the other hand whole system models like in (Strbac et al., 2012) tend to assume perfect consumer and market behaviour in order to perform global optimisation. Consequently, the dynamic interaction between different consumers and suppliers is lost. In reality, electricity suppliers interact in the wholesale market in order to supply consumers with very different demand profiles and flexibility resources.

Following these gaps in research, we propose an agent-based modelling framework representative of the UK electricity system which would highlight the benefits and potential issues concerning demand side management in the context of the evolving UK electricity system.

The modelling framework

The following chapter explains the main elements of the modelling framework used to develop two models used to answer the questions posed in the Introduction. The first model focuses on the heterogeneity of consumers, whereas the second model addresses the issue of interacting electricity suppliers. The following section describes the main elements of the modelling framework.

CONSUMERS

We consider a set of consumers A, where each agent $a \in A$ has a daily demand profile, $b_i^a(t)$for each daily period of simulation $i \in [1,H]$ of day t, where H stands for the total number of daily periods[4]. The consumer may be in possession of some flexibility resource (e.g. an electric vehicle[5] or small battery) with certain specifications of energy capacity e^a (kWh), minimum and maximum power constraints, f^a_{min} and f^a_{max} (kW) and efficiency η^a[6]. Consumer may also have access to electricity generation resource (e.g. rooftop solar PV).

In each daily period i, the consumer generates r_i^a kWh of electricity. The net demand for consumer a (to be provided by a supplier) can be calculated as

$$d_i^a = b_i^a + f_i^a - r_i^a, \forall\, i \in [1, H]$$

Each consumer is contracted to be supplied with electricity by a utility s[7], such that $s \in S$ (the set of all suppliers). Then, $A^S \subseteq A$ is a set of consumers signed up with supplier s. The consumer pays the supplier the retail price, $\pi^s(t)$ measured in £/MWh of energy used which is calculated according to (2).

It is assumed that if the consumer is not coordinated he will schedule his store selfishly. For a battery this would mean charging during times of low electricity demand (and hence prices), whereas for an electric vehicle this assumes plugging at maximum power at the time of arrival. When operating the

4. We drop the index for the day counter for intraday calculations from here onwards.

5. The case when flexibility resource is an electric vehicle assumes the presence of a home charging unit.

6. In the case of an electric vehicle it will also have constraints on start and finish time for charging.

7. We use the terms utility and supplier interchangeably in this context.

flexible demand resource, the following constraints must be adhered to:

C1: Maximum and minimum power constraints

$$0 \le f_i^{a+} \le f_{max}^a, 0 \le f_i^{a-} \le f_{min}^a, \qquad \forall\, i \in [1, H],$$

C2: Storage efficiency constraint

$$\sum_{i \in H} f_i^{a-} = \eta^a \sum_{i \in H} f_i^{a+},$$

C3: Energy that can be stored or used at a time slot

$$f_i^{a-} \le \sum_{j=1}^{i-1} \left(\eta^a f_j^{a+} - f_j^{a-}\right), \qquad \forall\, i \in [1, H],$$

$$f_i^{a+} \le e^a - \left(\sum_{j=1}^{i-1} \eta^a f_j^{a+} - f_j^{a-}\right), \qquad \forall\, \mathrm{i} \in [1, \mathrm{H}],$$

C4: no-reselling allowed

$$f_i^{a-} \le d_i^a, \qquad \forall i \in [1, H].$$

Where,

d_i^a total electricity demand of consumer *a* in daily period *i* [MW],

i,j period of daily simulation,

H total number of periods in a daily simulation.

For an electric vehicle we have an additional constraint:

C5: the time constraints for charging

$$\sum_{i=t_1}^{t_2} f_i^a = (SOC_2 - SOC_1) \cdot e^a$$

Where,

$f_i^a = \eta^a f_i^{a+} - f_i^{a-}$ is the net charge of the battery in time period *i* [MWh],

t_1, t_2 start and finish time of charging (specified by the consumer),

SOC_1, SOC_2 initial and final states of charge of the battery (as specified by consumer).

SUPPLIERS

Suppliers are energy utility companies responsible for supplying their consumers with electricity. Suppliers' objective is to fulfil the sum of its consumer demand in daily period *i*, B_i^S which is calculated as

$$B_i^s = \sum_{a \in A^S} d_i^a, \quad \forall\, i \in [1, H].$$

The supplier maybe in possession of his own renewable or dispatchable electricity generation technology, in which case the net demand required to be bought by the supplier from the market becomes:

$$D_i^S = B_i^S - R_i^S, \qquad \forall i \in [1, H].$$

Where,

R_i^S the amount of power generated by a supplier *s* in daily period *i* [MW].

The supplier is capable of selling electricity in the wholesale market at a price, p^s [£/MWh], calculated according to the following formula:

$$p^s(t) = p_{SRMC}^s(t) + \epsilon^s(t). \qquad (1.a)$$

The first term in (1.a), p_{SRMC}^S, is known as the short run marginal cost (SRMC) of generator type *s* calculated as:

$$p_{SRMC}^S = c_{varO\&M}^S + \frac{p_{fuel}^S(t)}{\eta^j} + \sigma_C^S \times p_C. \qquad (1.b)$$

Where,

$c_{varO\&M}^S$ variable operational and maintenance cost for a generator of type s [£/MWh],

p_{fuel}^S price of fuel used by an electricity generator of type *s* [£/MWh],

σ_C^S the emission factor for generator of type *s* [g CO_2eq/MWh],

p_c carbon price [£/g CO_2eq],

η^s efficiency of an electricity generator of type *s*,

ϵ^s the additional cost added by the generator[8] [£/MWh].

In case the generator turns out to be marginal in the merit order[9], it incurs an additional dynamic cost, c_{dyn}, which reflects the efficiency adjusted cost of generation, which is not modelled at the present moment.

Finally, each day, *t*, the supplier calculates the retail price as follows:

$$\pi^S(t) \qquad (2)$$

$$= \frac{\sum_{i=1}^{H} (R_i^S(t) \cdot p_{SRMC}^S(t) - (Q_i^s(t) + R_i^S) \cdot p^S(t) + D_i^S(t) \cdot p_i(t)\ )}{B_i^S(t)}$$

Where,

Q_i^S the amount of energy sold by supplier in daily period *i* [MWh],

$p^s(t)$ the asking price for a unit of energy by supplier *s* in day *t* [£/MWh],

$p_i(t)$ the market price for a unit of energy in daily period *i* and day *t* [£/MWh],

B_i^S the total energy supplied to the consumers [MWh].

Equation (2) can be split into 3 parts: cost of power generation used for self-supply, profit made in the market and the cost of purchasing additional electricity from the market.

THE MARKET

The market represents a pool of electricity generators selling electricity. The generators are stacked into a merit order based on the price they can offer in the market calculated according to (1), with the price going from low to high. Cheaper unit of electricity are typically sold first and hence electricity demand

8. The uplift covers the cost of electricity for distribution and additional costs incurred by the utility.

9. The last generator required in the merit order (see next section "The market").

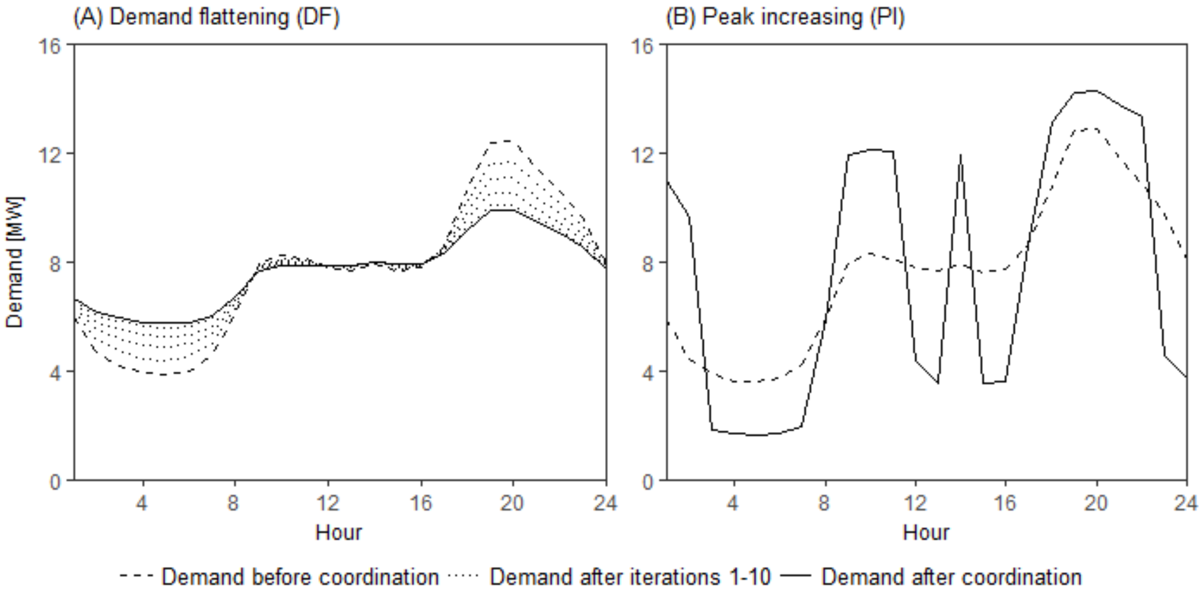

Figure 2. Demonstration of coordination mechanisms performed by the aggregator. Note: algorithm DDF achieves the same result as CDF but at the level of the consumer and not the aggregator.

and prices are positively correlated. The generator at the end of the stack is what is referred to as the marginal generator.

The wholesale price is calculated as the average price for a unit on energy required to fulfil global demand L_i, calculated as the sum of demand profiles across suppliers, L_i [MW]:

$$L_i = \sum_{s \in S} D_i^S, \qquad \forall i \in H \tag{3}$$

Where,
D_i^S total demand being fulfilled from the market by supplier s in daily period i [MW].

Supplier bidding

If the traditional supplier bids into the market, it enters the existing merit order. Supplier's available capacity, $Q^s(t)$ [MW], is then positioned in the row above the more expensive capacity but below the cheaper capacity. Any generator which bid above the marginal unit is unable to sell its electricity. Hence, it is critical for the supplier to set its offer right, because a price too high will mean it will be unable to sell whilst if the price is too low the supplier will lose out on the profit opportunity.

DEMAND SIDE MANAGEMENT APPROACHES

In this model we consider two levels of coordination: **distributed** and **centralised**. Distributed coordination refers to the case when the consumer self-schedules without considering the global system. Centralised coordination refers to the case when the aggregator schedules a pool of consumers. We also consider different purposes for coordination: **demand flattening (DF)** and **peak increasing (PI)**. DF assumes rational agent behaviour to smooth the demand curve in order to avoid paying higher market prices (Figure 2, left) while the PI algorithm leads to increased peaks resulting in higher market prices (Figure 2, right)[10].

The demand coordination methods considered in the paper are based on the algorithm developed by (Gan, Wierman, Topcu, Chen, & Low, 2013). For brevity we will not go into the details of the method but will mention that it is flexible and shows fast convergence (<10 iterations).

We adopt the following notation to refer to the algorithms:

1. Distributed with demand flattening (DDF) – consumers flattens own demand profiles;
2. Centralised with demand flattening (CDF) – the aggregator coordinates a set of consumers in order to flatten the aggregated electricity demand profile;
3. Centralised with peak increasing (CIP) – the aggregator coordinates a set of consumers in order to increase demand peaks of the aggregated demand profile.

Results and Analysis

Two models have been developed using the methodology described in the previous section. Whilst the components for modelling consumer and the market behaviour are similar the focus of the two models is different. The first model, was developed at University College London (UCL) and focuses on the difference in the impact of deploying centralised (CDF) and distributed demand flattening (CDF) coordination. The second model, developed as part of the summer programme at the International Institute for Applied Systems Analysis (IIASA), explores the influence of the market layer on the behaviour of the system. In particular, we expand on the case

10. PI algorithm is useful in the case when the supplier wishes to sell electricity in the market at a higher price.

Table 1. Summary of data and methods used for model I.

Model element	Data used and source	Method
Consumers	Daily demand profiles (half-hourly resolution) (Elexon, 2017) Annual energy consumption by sector up to 2040 (National Grid, 2016)	Daily profiles were aggregated into yearly profiles for different sector and scaled according to annual energy consumption data per sector.
Generation	Installed generation capacities up to 2040 Fuel and carbon prices up to 2040 Renewable generation profile (renewable.ninja.org) Generator costs (UCL, 2016)	**Dispatchable generators** – SRMC were calculated for each type of electricity generator according to (1.a) and stacked into a merit order based on installed capacities specified in each scenario **Renewable generators** – historical generation profiles were scaled according to installed capacities taken from FES
Storage	Installed storage capacities for pump and consumer storage up to 2040	The energy and power constraints were fed into consumer specification and then used in the balancing methods DDF, CDF, CIP
Market	Historical electricity prices (Elexon, 2016)	Electricity prices were calibrated for historical demand and wholesale values

Table 2. Experimental scenarios under Gone Green national policy.

Storage scenario	Coordination regime
NP	DDF
GG	DDF
SP	DDF
CP	DDF
NP	CDF
GG	CDF
SP	CDF
CP	CDF

when the CPI algorithm becomes a profitable strategy for the traditional utility.

MODEL I – CENTRALISED VERSUS DISTRIBUTED DSM

In the first part of the experiment it was of interest to observe the benefits of storage in the future UK electricity system under centralised (CDF) and distributed (DCF) coordination regimes. The data for the model has been primarily taken from the Future Energy Scenarios (FES) developed by National Grid (NG) (National Grid, 2016). The National Grid considers four cases for the evolution of the UK electricity system up to 2040:

1. No progression (NP)
2. Slow progression (SP)
3. Gone Green (GG)
4. Consumer Power (CP)

Using the data from FES, it was possible to simulate the evolution of the UK electricity system under the four scenarios. Table 1 summarises the methods for feeding the data into the model.

In order to isolate the effect of storage capacity integration, we kept the national scenario constant at Gone Green[11] whilst varying the values for installed storage capacities according to the four cases: NP, SP, GG, and CP (Figure 3). It was of interest to evaluate the economic savings achieved by smart coordination as a result of balancing storage operation with renewable energy supply. The "no progression (NP)" scenario was chosen as the base case and the annual savings were calculated as the difference between system cost in the scenario under consideration and the base case scenario. Table 2 summarises the experimental cases considered by the model.

MODEL SET-UP

We considered three types of consumers: residential, commercial and industrial. It was assumed that the storage capacities were split equally between the three types of consumers. Pump storage was considered as part of the system and used to balance electricity at the last stage of system coordination (after consumers).

The simulation was performed for 26 years in accordance with data availability with hourly resolution. The demand and supply sides were calibrated to historical demand and market prices. We compared the performance of DDF and CDF coordination schemes by calculating the financial savings as a result of peak shaving with installed storage under scenarios GG, SP and CP as compared to the base case (NP). In this model we had one aggregator performing CDF – the System Operator.

Observations

It was possible to observe that under all scenarios distributed coordination (DDF), whereby the consumers only smoothed own demand without considering the system, performed worse than CDF when the aggregator coordinate a pool of consumers (Figure 4). This was true of individual consumers as well as for the total system. Hence, under CDF the value of storage was higher than under DDF. Looking at the top two lines in Figure 4 in 2040 the difference between the two scenarios reached £30 million for Consumer Power (CP) case, whilst for GG and SP cases the difference comes at £21 million and £7 million respectively.

However, under all storage scenarios the domestic sector benefited most. Figure 5 shows the readings observed for the

11. This meant keeping all data (apart from installed storage) in accordance with the Gone Green scenario.

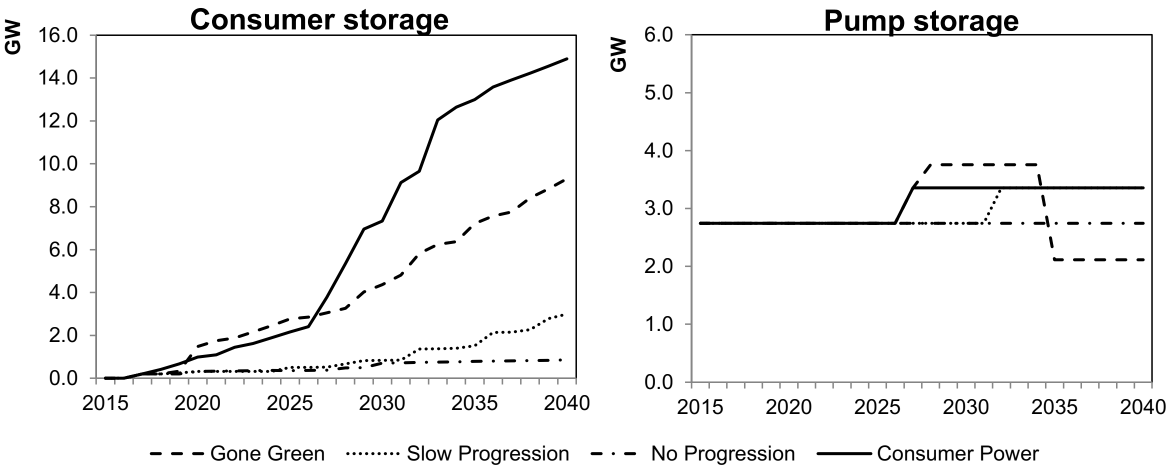

Figure 3. Installed storage capacities under different National Grid scenarios. Source: (National Grid, 2016).

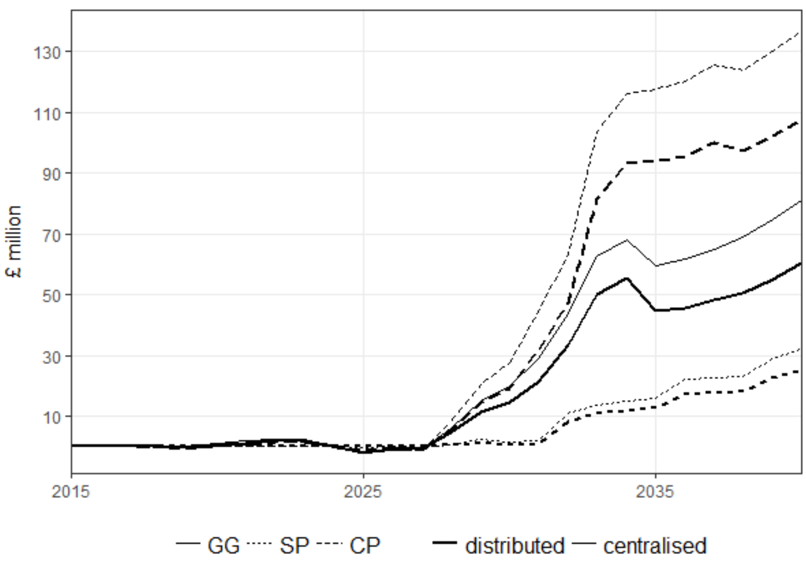

Figure 4. Annual savings by all sectors under different storage scenarios.

Gone Green scenario (similar behaviour was observed for the SP and CP scenarios). Considering that the installed capacity of storage was the same, this result highlights the unequal distribution of benefits that can occur with demand side management. A possible explanation for such behaviour comes from the fact that the demand profiles for commercial and industrial consumers are more similar than the domestic profile and hence it is these two sector that take on the burden of shaving domestic demand peaks. On the other hand, the commercial sector lost out. In fact, during the years 2024–2029 commercial consumers experienced negative savings in both distributed and centralised coordination cases. Finally, looking at the shape of the chart it is possible to see that the overall savings track the values of the installed pump storage capacity. This is explained by the fact that coordination with pump storage would always be performed last (in accordance with STOR balancing services) and would have the final say about the shape of the demand curve.

PART II – SUPPLIER GAMES WITH DSM

The second part of the project involved assessing the impact of DSM on the utility market in the UK. Two types of suppliers were modelled: vertically integrated traditional (TS) owning dispatchable power generators[12] and 'new' independent suppliers (GS) owning renewable generation capacity[13]. In this simulation the consumers were in possession of electric vehicles.

Whilst the green supplier had access to cheap wind energy, it was unable to fulfil its consumer demand without going to the market (where a traditional supplier profited from selling electricity). The TS could choose to reserve its capacity for supplying own consumers instead of selling it (in which case it had to go to the market to purchase additional power). The suppliers

12. Traditional utility represents one of the 'Big Six' suppliers currently operating in the UK.

13. Independent utility represents a green supplier such as Ecotricity or Good Energy.

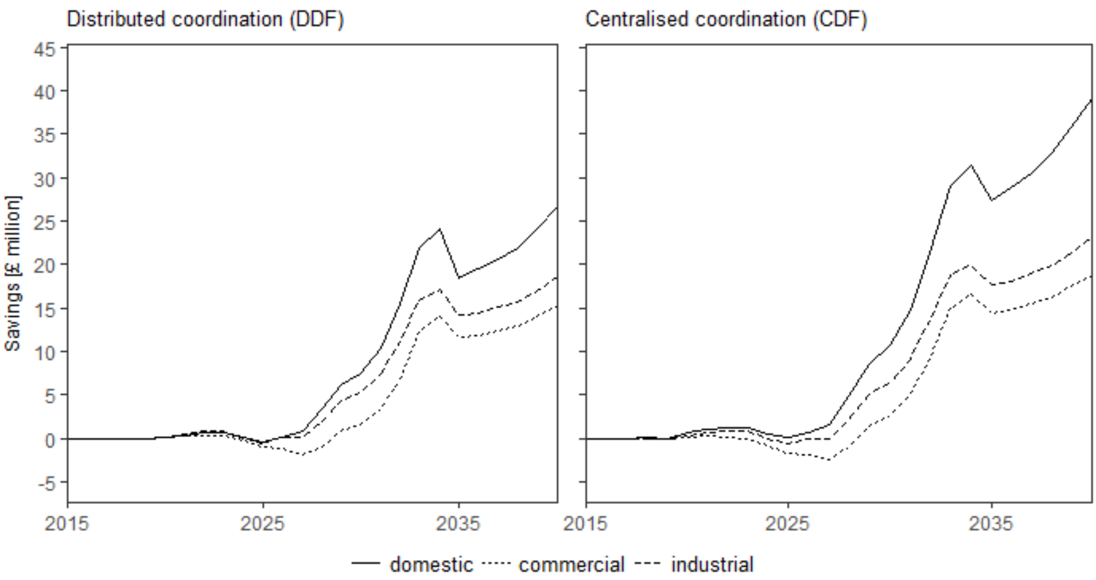

Figure 5. Annual savings by different sectors under Gone Green scenarios grouped by coordination type.

Table 3. Scenario parameter.

Scenario settings	Coordination by green supplier	Coordination by traditional supplier
S1. Changing the amount of renewable capacity available to the green supplier	NC/CDF	NC/CDF/CPI
S2. Changing the amount of dispatchable capacity available to the traditional supplier		
S3. Changing the amount of flexibility available to each supplier		

competed on the retail price offered to consumers by deploying different strategies available to them. A green supplier could deploy demand flattening coordination method (CDF) in order to maximise the use or renewable power. In addition to that, the traditional supplier could also increase demand peaks with coordination method CIP. This enabled him to set a higher offer when selling electricity in the market. For this to happen, the traditional supplier was allowed to learn how to adjust the self-reserve parameter and the offer.

Scenarios

We modelled 30,000 residential consumer equally split between a traditional and a green supplier. The scenarios tested in this modelled are summarised in (Table 3). For each scenario it was of interest to look at how the system behaved under different coordination techniques deployed by the suppliers. As discussed before, the traditional supplier had three options for coordination: no coordination (NC), demand flattening (CDF) and peak increase (CIP) whilst the green supplier had two coordination options (NC) and (CDF). In addition to this, the traditional supplier could adjust the self-reserve and offer.

Observations

The scenarios summarized in Table 3 rendered 48 experimental cases. It has been found that in 33 out of 48 cases TS was able to offer a lower price to the consumers. It can be explained by the fact that the traditional supplier had more tools to adjust to the market including the ability to sell electricity and increase demand peaks. However, it was constrained by a higher marginal cost it had to pay for generating own power. When considering different coordinating strategies, overall the traditional utility did better independent of the strategy it considered (Figure 6). On the other hand, for the green supplier to be more competitive it was necessary to flatten demand. In fact both utilities did better when they adopted demand flattening strategy.

As speculated, an increase in the amount of own generation capacity lead to improved competitiveness of both suppliers. However, increasing dispatchable capacity made a peak increasing strategy (CPI) profitable for the traditional supplier, which had an adverse effect on the system leading to higher demand peaks (Figure 7). In the case when only the traditional supplier (TS) coordinated with peak increasing algorithm demand peaks reached 38 MW which was worse when no coordination was applied (34 MW).

Conclusions and further work

This paper examined the potential issues that may arise in the physical and the market layers of the future electricity system as a result of demand-side management in the presence of storage. Two agent-based models were built using a similar modelling framework for this purpose.

The first model aimed to estimate the value of storage in the future UK electricity system. The national scenarios were taken from the National Grid model. These included four cases for the evolution of the UK electricity system up to 2040 (No Progression, Slow Progression, Gone Green and Consumer Power). The "No Progression" scenario was taken as the base case and the remaining three were evaluated against it in terms of the annual savings generated from demand-supply balancing with storage. It was of interest to compare distributed coordination (whereby autonomous consumers scheduled their own storage with the objective of flattening net electricity demand) with centralised coordination (whereby the aggregator instructed consumer scheduling with the objective of flattening global net electricity demand). Three types of consumers were modelled (residential, commercial and industrial) each having an equal share of storage. The modelling was able to show that centralised coordination led to higher annual savings for all three storage scenarios (Gone Green, Slow progression and Consumer power) for all consumer types. However, the benefits were unequally spread across consumers with the domestic sector benefitting most and the commercial sector losing out. A possible explanation given is that the domestic demand profile was very different to the other two leading to uneven distribution of benefits.

With the second model we investigated how a traditional supplier (in possession of dispatchable generation capacity)

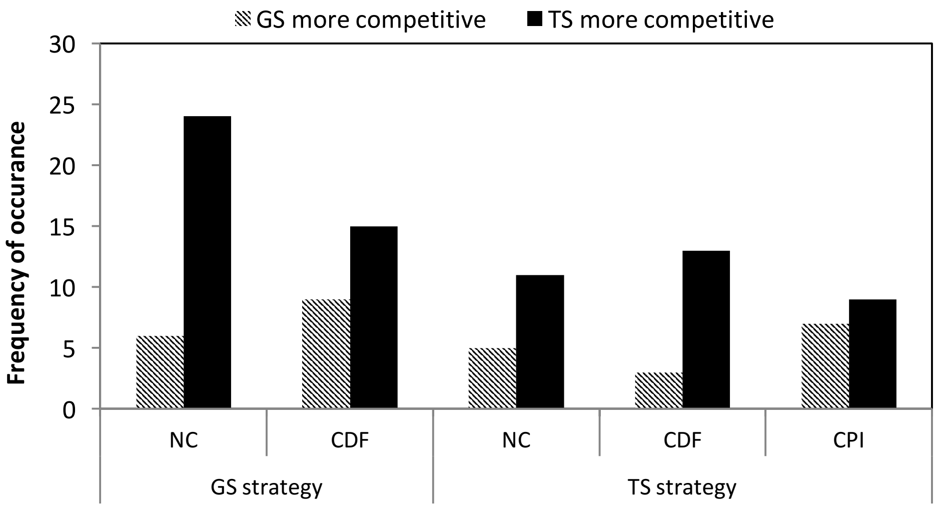

Figure 6. Comparison of strategy uptake and overall outcome for all cases. Key: none=no coordination; CDF=demand flattening strategy, CPI=peak increasing strategy

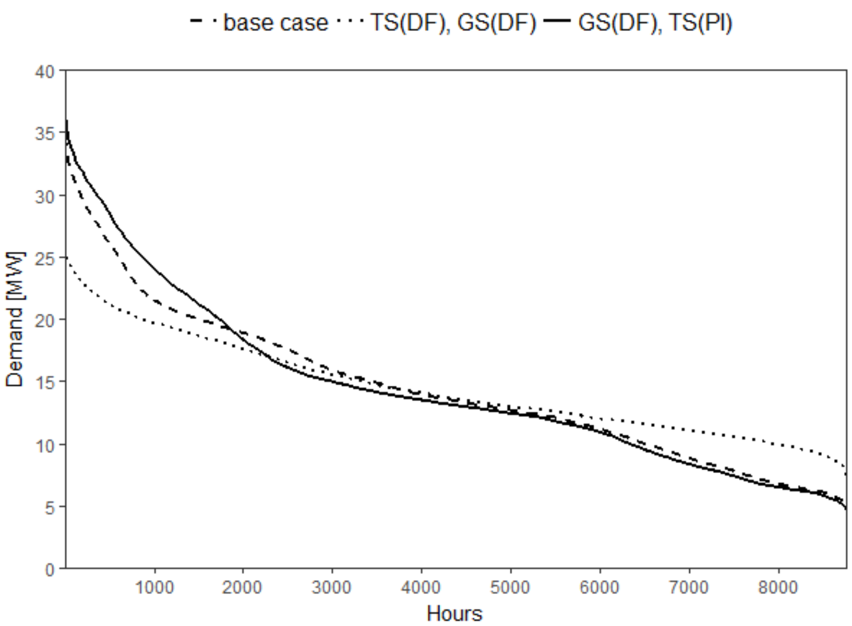

Figure 7. System demand distribution under scenario where the traditional supplier had more dispatchable capacity.

and a green supplier (in possession of a renewable generator) can gain a competitive edge as a result of utilising smart coordination strategies of consumer demand. Here we considered two algorithms: net demand flattening (for both types of suppliers) and demand peak increasing (for the traditional supplier only thus allowing it to increase its offer price in the market). The model showed that overall the traditional supplier was more competitive, as it had more tools to adjust to the market. In fact, with enough capacity the traditional supplier benefitted from instructing his consumer to increase demand peaks which had an adverse effect on the whole system.

Balancing electricity with storage can offer a promising solution to coordination of variable supply and help transition the UK electricity system to a cleaner more sustainable one. However, if not controlled well it could lead to negative effects for the whole system. In this work we attempted to highlight such issues, however further work is needed.

FURTHER WORK

The main ambition for further work is to merge the above models together. This will allow us to capture the complexity of the UK electricity system, and particularly explore the issue of how dynamic competition between agents (without incurring system chaos) can lead to optimal use of variables renewables.

We also hope to include the following developments:

- **Electricity generation**: extend the merit order beyond the short run marginal costs to include capital costs as well as transmission and distribution costs;
- **Consumers**: include the transportation sector and extend consumer storage to heat; equipping consumers with the ability to choose suppliers, include heterogeneous consumers per sector (e.g. different household size, income level);
- **Suppliers**: allow suppliers to predict future market conditions and adjust accordingly; replace discrete coordination algorithms with an ability to learn the appropriate signal based on predictions and historical outcomes.
- **Uncertainty**: in order to make the scenarios more realistic we aim to include uncertainty on the supply and the demand sides.
- **Unequal benefits**: further explore the source for unequal benefits arising between domestic and non-domestic consumers, run scenarios with unequal distribution of storage between consumers.

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