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Transmission–distribution coordination and transition to more actively operated distribution: why it matters

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1 Introduction

This Working Paper has been motivated by the growth of distributed energy resources (DER) on the electricity system in Britain, i.e. generation, storage and flexible demand that is connected at distribution network voltages, and the consultation published by Ofgem and BEIS in November 2016 on the subject of electricity system flexibility. It aims to give a very basic and rapid introduction to some of the issues and their origins.

In an economist's ideal world, there would be no need for any coordination at any level in the electricity system. Market participants would be allowed just to get on with what they do. However, in reality,

1. it is very expensive to store surplus electrical energy until such time as a buyer wants it (at an acceptable price); you therefore have to make it when it's wanted;

2. if it is possible to transfer electrical energy from one place to another, as a buyer you have a much greater choice of sources, i.e. a network facilitates competition;
3. a network also enables a buyer to find a source somewhere if they're absolutely desperate, i.e. it helps with reliability of supply;
4. if the network is meshed, you can have a continuous, uninterrupted supply even if there is the odd network or generator fault (provided adequate network monitoring and protection systems are installed and generators can respond in the right way);
5. however, by having an integrated power system, if system or individual component limits are breached, the whole system can go very wrong very quickly, and many of the responses you want from generators, in particular, are slow relative to the time constants of electromagnetic variations.

As a consequence of point 5, on an interconnected network, it seems that some kind of coordination is needed in real-time, i.e. system operation. How much of it needs to be done by one party, how much can be delegated to some other party or parties? If the answer to the latter is more than none, how can the interactions between different parties best be managed?

2 Why have an interconnected power system?

System operation, at some point near to real-time, needs to be coordinated on an interconnected system (if you want, for the most part, supply to be continuous to energy users). The system operator needs various facilities to be able to do that. These include the ability to take control actions – operational measures, enabled by various devices – and capacity, both of generators (including the capacity to deliver control actions) and of the network. (This should, in general, also include the possibility to take or encourage control actions on the part of at least some energy users, and some two-way storage). The capacity or capability needs to be put in place in advance and depends on assets of some kind, whether primary (carrying power) or secondary (monitoring, communications and control). The task of system planning is to provide sufficient facilities to enable the system to be operated.

The main objective across system planning and operation is a whole electricity system optimal balance between investment in assets (whether primary or secondary) and the use of operational measures. This relates to all of the following:

1. enabling trade of energy from all (or nearly all – some *de minimis* level of participation may still be appropriate) sources of electrical energy, something

that is dependent not only on market arrangements but also on network capacity;

2. not threatening system operation, e.g. in respect of allowing a system operator to understand the current and emerging state of the system;
3. enabling system operation, e.g. in providing ancillary services such as response, reserve, voltage control/reactive power and black start;
4. providing a satisfactory level of reliability of supply to energy users.

Achievement of the above objectives can be discussed in respect of spatial issues, i.e. the locations at which generation, demand and storage are connected relative to existing or putative network capacity that allows the transfer of power between different locations[1]; and temporal issues, i.e. the matching of generation and demand at each moment in time and transitions between time intervals in light of changes to generation and demand. Spatial issues concern not only transfers of power within the transmission network but also between transmission and distribution networks and within distribution networks.

Spatial and temporal issues with respect to the above objectives are discussed below.

3 Spatial issues

Items 1 and 4 from the list in section 2 above are broadly concerned with spatial issues and the capability of networks to transfer power between one location and another.

In respect of system planning and operation, item 1 is primarily concerned with a balance between

a) provision of physical network access to facilities that, at least some of the time, are producers of power[2];
b) provision of rights to facilities that, at least some of the time, are producers of power[3] and which enable them to access the network;

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[1] Ultimately, reliability of supply is also concerned with temporal issues around the simple availability of power.

[2] This includes storage with two-way energy conversion capability.

[3] Although the primary purpose of the discussion is to illustrate the issues arising in respect of generation, of course energy users want to use the network as well, in order to receive energy. They should acquire the rights to draw power from the network. In order that network costs can be recovered, in principle both producers and users of power should pay for their rights to use the network. The fees charged for this might be dependent on the location. The differences might reflect the relative costs of access and thus provide

c) building of physical network capacity.

The third of the above, i.e. (c), includes network capacity that can be made available by, for instance, network reconfiguration, redirection of power flows (such as via use of phase shifting transformers) and release of network capacity revealed through real-time thermal ratings. Any additional network capacity judged to be necessary should be delivered through the most cost-effective means.

The difference between (a) and (b) is that access rights that exceed the physical capability for some period of time will need to be bought back for that period. The total duration of such buy-backs, the volume of actions and the price paid for them (which could be zero) inform a judgement, along with the cost of network capacity, on the building of network capacity which, in turn, provides the physical access with which (a) is concerned.

A key issue in distribution network access arrangements at present is that, where network access buy-backs are used – exclusively, to date, through 'active network management' (ANM) schemes – they are bought back at zero cost to the distribution network operator (DNO). There is uncertainty in respect of the duration and volume of such buy-backs. This arises due to, for example, variation in weather conditions and the behaviour of demand. (For example, there might be a net export constraint in the particular network group within which a generator is connected, and part of the demand in that group might close). However, where there is no cost to the DNO, they face no risk and there is no incentive to manage risk. All the risk falls on the connectee. It might be argued that DNOs' remuneration arrangements make no provision for such risk. However, a key consideration is the following: *risk is best borne by parties that are best informed about it*. The key information relating to network access buy-backs concerns the capacity of the network and the behaviour of the different parties connected to the network. DNOs have access to this information and individual connectees, apart from in respect of their own behaviour, do not. Thus, in order to reach a satisfactory balance between (a), (b) and (c) above, it would seem to be critical that

i. clear and fair arrangements are developed for the buying back of network access from connectees;
ii. DNOs are exposed to some risk in respect of buying-back of access, which means that the cost to the DNO of each unit of buy-back should not be zero.

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incentives to connect at one place rather than another. Furthermore, these fees might also change in time, e.g. annually or hourly as conditions change and the need for the network or its utilisation changes.

Having established the above principles, the task is then to determine what form ‘clear and fair’ arrangements take and how to determine buy-back prices[4]. Parallels can be drawn with and lessons learned from transmission access and constraint management arrangements, though it should be borne in mind that distribution connectees might not have the organisational capacity to manage complicated arrangements and that, overall, the arrangements will need to deal in future with a much larger total number of connectees than are experienced at transmission levels.

Item 4 from the list in section 2 is also concerned with identification of the ‘right’ amount and form of network capacity. However, it differs from 1 in that, in general at present (though it might be different in future), energy users have no clear means of expressing their own preferences for reliability of supply. (In respect of 1, connectees can, in general, express preferences for the level of access).

4 Temporal issues

A power system is dynamic, i.e. it changes all the time as loads are connected and disconnected, generators connect, change their outputs or disconnect and any connected two-way storage changes between charging, discharging and doing nothing. Many of the changes are unplanned or uncoordinated, e.g. most changes in demand, variations in wind speeds or solar radiation affecting output from renewable generators or faults affecting generators, the network or demand. If supply to energy users is to be continuous, the system must adapt to changes. This is done via some automatic actions, e.g. frequency response, and some manual actions such as scheduling and utilisation of short-term operating reserve (STOR). When changes occur, the system must make a successful transition to a new equilibrium condition. To do this, ‘headroom’ or ‘footroom’, i.e. ‘margin’ must be

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[4] Some inspiration might be taken from Australia where, apparently, a seeming need for extra network infrastructure is subject to a market test not only of the cost of that capacity but also of ‘non-build’ options. This might include, for example, generation or demand offering to temporarily reduce their export or import. The terms of the ‘service’ they offer might include up to a certain number of MWh or kWh in any one year at a given per unit price. There might also be some stipulation in terms of maximum MW or kW at any one time, or the times at which the buy-back can be invoked. However, it is hard to say how effective this type of possible arrangement might be when there is only one party that could affect the power transfer on the key network corridor. Meanwhile, could it be envisaged that one party might offer a service in respect of different network constraints? Will the service be available for one if it has already been used for another? Perhaps utilisation for the first reduces the need for the second, but what if they are priced differently? Is it clear how much they should be paid?

available on flexible resources, i.e. those that are capable of changing their state in a controlled way. However, such margin implies operation away from the most efficient, least cost state in which system operation would ideally take place given perfect foresight of changes. A balance needs to be struck between the cost of margin and the risks associated with having insufficient margin.

Historically, generation resources connected to the power system have tended to have at least some flexibility, even nuclear power stations that are often regarded as having no flexibility; even if they are not designed or scheduled to flex output significantly, they are still capable of ‘inertia response’ by which some of the kinetic energy of the machines’ rotors is transferred to the system in the event of a frequency drop. Different generators will have different dynamic characteristics – in particular, ramp rates and inertia – and costs. Changes to voltages also require some timely responses in order to avoid voltage instability[5]. Having in mind some ‘credible’ system disturbances, whichever party is responsible for managing system frequency – usually a single system operator (though it can be shared among a number of them provided there are some rules about how to share the responsibility) – tries the minimise the cost of achieving the transition to a new steady state by buying just enough expensive, fast-acting response to buy time to access slower, cheaper reserve.

One question that arises is how these dynamic services – that enable transitions between successive stable system states – might best be procured. From the beginning of liberalised electricity supply industries they have been treated as something can’t easily be captured within the normal trading of energy and have instead been managed under a special heading of ‘ancillary services’. However, by breaking the trading of energy down into shorter blocks of time each of which has its own supply and demand curves, it seems that at least of the dynamic aspects could be managed as each successive period would varying levels of demand and varying availability of generation to meet that demand. Where the trading becomes more complex is in recognising generating units’ different abilities to change outputs from one time slice to another.

Historically, most dynamic system services have been provided by generators or two-way storage, in principle at least some of them could be provided by flexible demand. Just as for generators, the dynamic characteristics of different providers of

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[5] Changes to the thermal loading of assets also require timely responses though the rate of change of temperature of most power system assets means that there is more time than in respect of frequency, voltage or angular stability.

demand flexibility need to be taken into account, e.g. how quickly (and reliably) it can respond to unplanned changes on the system. (Advance, planned changes to a schedule of consumption can help on timescales above half-an-hour; to contrast such actions from responses to unplanned changes that take place at uncertain times, i.e. demand side response, planned changes might be referred as demand side management. Both of these are examples of flexible demand[6]).

5 Spatial and temporal interactions

Location and timing issues cannot, in the end, be divorced from each other. This is especially true in respect of the following.

i. Reliability of supply, i.e. viewed in one particular way, what is the probability that an energy user at a given location will have their energy service demand met at all times? This depends both on their location relative to the network's capacity to import power and the availability of that power at that time. The latter depends, in the long term, on power production capacity and, in the short term, on how temporal variability is managed through the procurement and utilisation of response and reserve services.
ii. The ancillary services of voltage control and reactive power. Control of voltage – to provide an adequate quality of supply to energy users, i.e. within acceptable limits, to avoid over-stressing network and network users' equipment, and to avoid voltage instability – is primarily achieved through the generation or absorption of reactive power[7]. This must be done by the right amount at the right time at the right place. (Because each network element itself resembles, depending on power flow conditions, either a generator or absorber of reactive power, reactive power cannot be effectively transferred over large electrical distances. It is thus very difficult to have a competitive market for reactive power).
iii. The ancillary service of black start capability or support. In the event of a system blackout, in order to restore the system, generation capable of self-starting, i.e. starting to produce power without already having an off-site supply of power, must be available at the key time. However, because a first function is to energise the network, it must be local to the section of network to be energised. The network can be energised in stages with one, already

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[6] The Review of Low Carbon Networks Fund projects produced on behalf of UKERC and HubNet included a taxonomy of flexible demand in which 'demand reduction', 'demand side management' and 'demand side response' were defined.
[7] The transfer of active power also has an influence. This is especially true at lower distribution voltages where network branches have high per unit resistances.

energised section serving to energise another, provided sufficient reactive power resources are available at the right locations. (See ii above). The progressive restoration of load requires increasing amounts of generation; this might be located anywhere but the ability to serve the load will be subject to network power transfer capability and the same voltage control and reactive power issues discussed above.

In GB to date, network power transfer capability relative to where providers of response and reserve services have habitually been located has not tended to limit access to those services. In other words, spatial issues have not, so far, significantly affected the procurement of response and reserve services. However, this cannot be assumed to continue to be the case:

i. The network has finite power transfer capability. If it is to be used to provide access to remote resources to correct changes to the generation and demand balance, it cannot already be fully loaded.
ii. Distributed energy resources (DER) – generation, storage or flexible demand connected within the distribution networks – is an increasingly large resource at least part of which may be highly attractive in the provision of response and/or reserve services. However, they can only be utilised if network capacity, at the key moments, within the distribution networks and between distribution and transmission is sufficient.

One important feature of the network is that it allows local imbalances to be aggregated into a single, whole system imbalance. Normally, local imbalances within the same system to some extent net off each other. Viewed another way, the network allows response and reserve to be shared between different areas and, thus, the total response and reserve to be reduced.

6 Observability and controllability

The management of both the temporal and spatial dimensions of power system operation and the planning of new facilities to support operation in the future depends on knowing what the state of the system is, i.e. how heavily loaded each branch of the network is and what the voltages are at each substation. That is, the system must be observable. In order for limits to be respected, either the network's capacity must be so large that its limits will never be breached under any reasonably foreseeable circumstances or key individual system states must be controllable. Observability depends on measurements at key locations on the system and timely communications of measured quantities to relevant automatic controls and/or the system operator. One of the main dimensions of controllability on the transmission system has been the ability to modify – to increase or to decrease – the active power production of generators. As more generation connects to the distribution networks, this becomes increasingly important also there, but distribution networks have historically had very limited observability and distribution network operators have, to date, tended to make use of only very few controls and then to do so, for the most part, only in response to faults. If the potential of flexible demand to contribute to cost-effective system operation and help to reduce the need for new system assets is to be fully exploited, significant advances in distribution network observability and controllability are required with the ability to deal with vastly increased numbers of active components than are managed by the transmission system operator today.

7 Asset-based solutions or operational measures

Much of what Ofgem has been proposing in respect of different roles within the power sector seems to arise from the idea, perpetuated by some academics, that regulated network owners are *always* incentivised to undertake capital expenditure, invest in new assets and increase the size of their asset base even when those investments do not appear[8] to represent correct decisions in respect of the development, maintenance, and operation of an "efficient, co-ordinated, and economical" system for the transmission or distribution of electricity and facilitation of competition in the generation and supply of electricity.

Relative to the regulatory regime that prevailed prior to RIIO network regulation[9], this idea, in its simplest form, might appear to neglect the following.

- Income is set by the regulator at each price review for the coming price control period. It is set such that it covers what are regarded as reasonable operating costs, the cost of new capital investment and the recovery of previously incurred capital expenditure. As part of a network owner's submission of information for a forthcoming price control, there is arguably an incentive to 'talk up' future capex requirements such that the network owner's revenues in the forthcoming price control period are maximised.
- Once prices are set for a particular price control period, i.e. revenues are set, there is arguably an incentive to *avoid* capital expenditure. This reduces cost in the short term, in particular the cost of borrowing, albeit at the expense of continued future income in subsequent price control periods linked to the size of the asset base.

[8] There is always some uncertainty…

[9] RIIO stands for Revenue = Incentives + Innovation + Outputs

- Assets deemed not to have been required are subject to being regarded as stranded and struck from the asset base thus attracting no income.
- Most network licensees in Britain are now part of companies that have much wider interests than just ownership of regulated power networks in Britain. Any potential investment requires the raising of funds and will be compared with alternative uses of funds that are available to the parent company. Very often, investments other than in regulated power network assets in Britain will appear more attractive[10].

Under RIIO, DNOs' future expenditure requirements are not assessed in terms of separate categories of capex and opex but in terms of total expenditure, i.e. 'totex'. An income stream is set in respect of totex. In principle, this allows – indeed, incentivises – a DNO to choose a cheaper operational solution in favour of a more expensive, asset-based one and to realise a surplus (or reduced deficit) relative to their income.

Also under RIIO, both the transmission and distribution network owners' income streams are subject to adjustment relative to, for example, volumes of new generation or demand connections. Thus, if capex is undertaken in anticipation of, for example, demand growth, that does not take place, income will be reduced and, if the income adjustment is set correctly, at least part of the cost of the new assets will not be recovered.

The above factors all suggest that, while its possibility should not be neglected, the incentive of network owners to always invest in new assets may have been significantly overstated. The necessity of certain regulatory changes proposed by Ofgem to address that incentive may therefore be questioned.

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[10] It might be regarded that this factor would lead to *under*-investment in network assets rather than over-investment. Licence conditions, including the obligation to comply with planning standards, are key to avoiding this. Incentives such as the customer minutes lost (CML) and customer interruptions (CI) incentive are also important.