WESTERN POWER DISTRIBUTION

INNOVATION

NEXT GENERATION NETWORKS

SOLAR YIELD NETWORK CONSTRAINTS (SYNC)

Technique 4: Discussion Paper

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1 Project Overview

WPD has connected significant amounts of embedded generation to its distribution network in recent years. This includes a large variety of different technologies, dominated at first by wind and more recently by solar PV.

With so much generation already connected, and significant quantities in the pipeline, most of the latent capacity within the network has now been utilised. As such WPD is looking at ways of releasing extra capacity in the most economically efficient manner. Alongside the use of traditional reinforcement, the roll out of alternative connections has been one of innovative manners this has been done, building on the flexibility of generators. These give the option of trading off capital expenditure and time delays against potential curtailment. This moves from a passively operated network to a more active one.

Whilst the inherent flexibility of generation is now being used, the flexibility of the demand side is as yet untapped.

As part of the SYNC project we looked to test a range of Demand Side Response (DSR) techniques to help address many of the different challenges being posed by PV generation. By engaging with industrial and commercial (I&C) customers we could release additional capacity or even improve power quality.

There are 4 techniques that project SYNC investigated:

(T1) - Automated demand increase / generation limiting in line with variation in solar yields.

(T2) - Directly matching flexible load with flexible generation

(T3) - Manually dispatched response signals from a WPD control facility (DSR)

(T4) - Creation of suitable ToU (Time of Use) tariffs to encourage appropriate demand

The project required significant engagement and involvement of third parties including demand customers, generators, storage operators and National Grid. WPD built on the learning gained in the FALCON project and directly manage a full service program directly. By doing so WPD attempted to demonstrate how to maximize value to the industry and minimize the cost to customers.

2 T4 Overview

T4 focussed on the way DNOs charge for use of their networks, the Distribution Use of System (DUoS) charges. Whilst distinct from directly called demand side response, the underlying methods of charging for use of the network can have a significant impact on customer behaviour. These underlying trends can increase or reduce the requirements for DSR by commercially incentivising behaviours such as load shifting away from peaks.

The aim of T4 was to stimulate discussion around these charges and the potential impacts they would have on customer behaviour and the requirements of DSR.

Since the start of project SYNC, the topic of network charging has come to the fore, with many detailed studies and recommendations into the topic. Network charging is now a highly discussed topic and featured heavily in the Ofgem/BEIS call for evidence on "a smart and flexible energy system". It is also the subject of Ofgem's Targeted Charging Review consultation and a key element of the ENA's TSO-DSO project (workstream 4 is focussed on charging).

With such changes in the industry and new formal forums to discuss the topic, the scope of T4 has been reduced to avoid duplication and to focus on a centralised discussion on the topic. Details are available under change request CRF01.

The following document briefly summarizes current network charging as well as highlighting some potential changes identified as part of the project. These views can be carried into the wider discussions where appropriate.

3 Current Charging Methodology

The way DNO's charge for the use of their system is governed by the Distribution Connection and Use of System Agreement (DCUSA), a multi-party contract between electricity distributors, suppliers and generators. This is a constantly evolving document with hundreds of considered and applied changes since its inception in 2006.

This is built around a few core principles:

- It must allow DNOs to comply with their licence conditions
- It must facilitate competition
- It must be cost reflective
- It must remain up to date.

Alongside these core principles, Ofgem have also indicated that the methodology must be simple, transparent and predictable. Also cost reflectiveness must be forward looking and seek to send customers a price signal about the costs their connection could impose on the network of the future.

To apply these principles, 2 charging methodologies are used:

- The Common Distribution Charging Methodology (CDCM): used for connection below the Extra High Voltage (EHV) level. This covers the vast majority of distribution customers and provides generic, area wide tariffs.
- The EHV Distribution Charging Methodology (EDCM): used for EHV connections, this generates site specific tariffs.

The outputs of these processes are detailed on each relevant DNO's websites. WPD's can be found here: https://www.westernpower.co.uk/About-us/Our-system/Use-of-System-Charges.aspx

It should also be noted that due to the regulated nature of DNOs, DUoS tariffs are designed to recover an allowable revenue. The value of this is determined through the price control settlements with Ofgem. The current 8 year settlement started in 2015. If DNOs over or under recover in a year, subsequent tariffs are adjusted to rebalance their position (with a 2 year lag).

Another key characteristic of DUoS charging is the indirect way it is billed. DUoS charges are levied against electricity suppliers rather than customers directly. As such it is up to the supplier's discretion as to whether to treat the charges as pass through items or to amalgamate and aggregate them. As such price signals sent by DNO's can be muted or masked before they get to customers.

3.1 CDCM

3.1.1 How it works

The CDCM methodology distributes the costs of running a distribution network by looking at the costs involved in meeting an increment in capacity. The 500MW model is used to determine the allocation of hypothetical costs across the voltage levels including amortisation and return on capital for assets required to accommodate 500MW of new demand (minus LV services) on a hypothetical distribution network built to current standards and configurations. It differs by licence area to accommodate the different network make-ups.

This model is used to allocate costs by network level, developing an understanding of the relevant costs of the different voltage levels. A separate service model is used to understand the costs of maintaining service connections.

The CDCM model then uses these costs to produce yardsticks, £/kW/year values for each network level. The kWs used combine metered loading data, with loss adjustments and diversity factors, to assess the contribution of each charge type and each network level to the system Simultaneous Maximum Demand (SMD). Certain costs are then subtracted to be taken as standing charges. These are based on pre-arranged standing charge factors. Reactive power is also considered for certain tariffs. The extra charges and yardsticks are then used to create pre-scaled tariffs, summing up the relevant network levels for each tariff type. These pre-scaled tariffs are compared to predicted network flows and the DNO's allowable revenue and then scaled either up or down to match it.

Multi rate tariffs add some additional complexity. Here single network users are broken into the different rates and costs are allocated against their relevant contribution to the system maximum demand. These are used to represent the difference in cost of running the network for the different rate periods.

This is a complex but open process. Full working spreadsheets for the CDCM model are available on our website, which go through each step of the process. The aim is simply to get a relative cost of different voltage levels and time bands towards the running of the network. The model is forward looking and is focussed on potential costs of future load additions rather than historical costs.

3.1.2 Structure of tariffs

The whole process delivers several different tariffs. For non-half hourly metered customers (domestic or small Industrial and commercial) charges are made from simple unit rates and a daily fixed charge. There can be up to 2 unit rates to allow for E7 tariffs.

For half hour metered customers, tariffs are made up of 3 unit rates as well a combination of fixed charges, capacity charges and reactive power charges. The 3 unit rates are split by time periods into Red, Amber and Green time bands. These are set differently by the different DNO's but are meant to represent the different loadings on the network. The time bands differentiate between weekend and weekdays. The table below shows these time bands for WPD's South West licence.

Time Bands for Half Hourly Metered Properties			
Time periods	Red Time Band	Amber Time Band	Green Time Band
Monday to Friday	17.00 - 19.00	07:30 to 17:00 19:00 to 21:30	00:00 to 07:30 21:30 to 24:00
Weekends		16:30 to 19:30	00:00 to 16:30 19:30 to 24:00
Notes	All the above times are in UK Clock time		

The table below shows some example tariffs for HV half hourly metered customers (South West customers 2018/2019).

Tariff name	Red Charge p/kWh	Amber Charge p/kWh	Green Charge p/kWh	Fixed Charge p/MPAN/day	Capacity Charge p/kVA/day	Reactive Power Charge p/kVArh	Excess Capacity Charge p/kVA/day
HV HH metered	6.463	1.383	1.324	90.23	2.78	6.82	0.072

HV generation Non-intermittent	**-5.442**	**-0.132**	**-0.046**	**43.50**		**0.096**	

It should be noted that the method of scaling the different time bands has changed for tariffs beyond 2018. This has the effect of flattening the rates. An example of the previous rates are shown in the following table of charges (South West customers 2017/2018). This has far stronger differences between the time bands. More details on the changes can be found on the DCUSA website under DCP 228.

Tariff name	Red Charge p/kWh	Amber Charge p/kWh	Green Charge p/kWh	Fixed Charge p/MPAN/day	Capacity Charge p/kVA/day	Reactive Power Charge p/kVArh	Excess Capacity Charge p/kVA/day
HV HH metered	**19.170**	**0.117**	**0.046**	**81.52**	**2.57**	**0.252**	**2.57**
HV generation Non-intermittent	**-5.267**	**-0.124**	**-0.051**	**39.31**		**0.099**	

3.1.3 Limitations

The CDCM method is designed to allocate costs appropriately, based on a demand driven system. In such a system generation can help reduce network peaks and is treated positively. Generators are given a negative demand coefficient in the model which transfers through to a positive payment for generation. Whilst it is undoubtedly true that generation at times of peak demand can help the network, this ignores some of the constraints now being caused at times of low demand. Viewing the distribution as a multi directional network may now be more appropriate.

Generation unit rates are determined as the inverse of the pre-scaled demand unit rates, therefore producing credit unit charges Furthermore intermittent generation is not subject to multi rate tariffs; as such energy exported in the middle of the night receives the same level of credits as during peak evening load. In addition, as the same cost per kW is used, intermittent generation is paid more for generating at times of low demand (amber and green periods) than non-intermittent generators.

A further limitation of the CDCM method is the lack of seasonality. Based on a network built around demand this was not required. In fact this helped spread the cost of running a network across the year rather than being solely based around the winter peaks. However as the network now has summer peaks of generation, the current lack of seasons seems limiting. As such the amber rate remains during the summer day, pushing flexible load into the overnight green period and away from the time of peak generation.

The coarse, licence area wide, approach to the charging, as well as the long term approach to the 500MW model also limits the amount the charging methodology can target price signals. This ignores short term network issues and means that any limitations and costs of a particular network are passed to all customers and hence attenuated. This gives the advantage of stable pricing and ease of calculation. As such the granularity of any pricing needs to balance the sharpness of the price signal versus the volatility in pricing, There is also the difficult balance between cost reflectiveness and overly penalising customers by geography.

3.2 EDCM

3.2.1 How it works

The EDCM process is much more granular than the CDCM method and was aimed at deriving cost reflective tariffs for the fewer much larger EHV customers. The objective of the EDCM is to produce a cost reflective set of charges that use existing network capacity more efficiently and avoid prompting inefficient network reinforcement. This is achieved with locational pricing, with higher prices where network capacity is scarce and much lower prices where it is plentiful.
The detailed process is very intricate but can be summarised in 4 steps:

1. Modelling of networks using one of 2 techniques (LRIC or FCP) to determine charges related to reinforcement
2. Allocation of DNO Party costs
3. Adds a scaling element to charges which is related to allowed revenue Adjustment for IDNOs

The two models: FCP and LRIC, aim to produce a £/kVA/annum cost that is reflective of the cost of future network reinforcement. Each model approaches this in a slightly different manner. The FCP method is zonal, it looks to assess whether changes in demand on the network will cause an overload in a 10 year study. If an issue is identified it will determine the timing of such reinforcement and hence the costs. The LRIC method is nodal and looks to assess the effect of an incremental change to the network. It looks to compare the net present value (NPV) of the base reinforcement versus the NPV following a 0.1MW increment at the node.
Both methods look to set a charge on the customer based on the likelihood and proximity of future reinforcement. This pushes up costs in highly utilised areas and reduces them where capacity is abundant.

3.2.2 Structure of output tariffs

The EDCM process produces separate tariffs with multiple elements for each location, for both import and export.

These are composed of “Super Red” unit charges (p/kWh), fixed charges (p/day), capacity charges (p/kVA/day) and exceeded capacity charge (p/kVA/day).

The unit rates are only valid for the super red time band of which is the time of DNO peak loading. This differs by licence area but for the South West area is set to: 17.00 till 19.00 for weekdays from November to February (excluding 22nd Dec to 4th Jan).

For demand these unit charges are used to recover the costs of the wider network, (via the remote or parent and grandparent charges depending on the methodology). This follows the reasoning that due to diversity the only contribution to wider capacity limits is the consumption at peak loading. The capacity charges are used to recover the costs of the target location (via the local or network group charges depending on the methodology). This is based on maximum capacities due to the reduced diversity at the level of connection. The capacity charges are also used as the mechanism for revenue scaling. The fixed charges are used to recover the costs of operating sole use assets. They also incorporate the recovery of any transmission charges/credits as well as network operating costs. There is no explicit reactive power charge as this is considered in the LRIC and FCP methodologies, hence covered by the existing tariff structure.

For generation customers the unit charges (applicable during the super red time band) are reversed into credits. These credits are only offered to customer with a non-zero F factor (who can contribute to security of supply). The capacity charge is used to recover the DNO’s target generation revenue and the fixed charges are used to recover the costs of the sole use asset operation.

3.2.3 Limitations

There are several key limitations to the EDCM process.

Firstly it is very onerous to run. It was designed for a system with very few EHV connected customers. However with the proliferation of EHV connected generators, the number of nodes and calculations required has grown hugely.

Furthermore the locational element leads to very large pricing volatility. The arrival of additional load in an area can see charges to existing customers increase dramatically.

A final limitation is the very small time frame covered by the super red rate. This is based on the original focus of a demand dominated network. However this means there is no consideration of the summer peak in generation.

Both charging methodologies have their benefits, however they were both built for demand dominated networks. As such their treatment of generation is generally limited and simplistic. Whilst acknowledging some of the benefits of generation and even the effects on network flows (EDCM) they do not readily acknowledge the potential issues caused by it.

4 Potential changes

In this section we have outlined several high level options for amending the current charging methodologies. These are by no means the only variations possible but are here to stimulate discussion. It may also be possible to combine elements of several options.

4.1 Introduction of seasonal charging

One potential option would be to add seasonal charges. These would allow the differentiation of tariffs between seasons and acknowledge the differing network conditions in winter and summer. This will make the charging more cost reflective, but without other changes would push revenue collection further into the winter months.

4.2 Introduction of location specific charges for CDCM

Changing the granularity of charging and focussing on a less hypothetical model would allow much stronger pricing signals for reinforcement. This would prevent the financial incentives for specific behaviours being attenuated across all customers and provide a more cost reflective charging structure. This would help new sites consider more network friendly locations by adding an operation cost to the placement of sites in low capacity areas. Stronger price signals will however lead to more volatility and could be very punitive in some locations.

4.3 Considering generation led reinforcement

This would acknowledge that DNO networks are no longer purely demand driven. As such there are operational and reinforcement costs associated with generation. As such the recoverable revenue could be split and the processes run in reverse for generation. The provision of credits could be kept in both methodologies to acknowledge the benefits of generation at times of peak demand and demand at times of peak generation. This could be incorporated with existing flows within EDCM but would require a change to the underlying CDCM methodology.

4.4 Capacity charging

This option would involve charging for DNO networks on a predominantly kW rather than kWh basis. This acknowledges that the costs to DNO's are based on power requirements rather than energy. Networks are built around contracted maximum demands and so reflecting this more strongly in charging may be more cost reflective. There are multiple variations based on when and how often the power values are taken. There are maximum demand charges in the current methodology; however they currently make up a small percentage of DUoS revenues.

4.5 Flat charging with additional DSR

This would move away from the any locational/seasonal issues for base costs, setting out a fixed based cost. This could be derived on a kWh or kW basis to recover a set revenue. DNO's could then raise specific and localised DSR programmes on top of this to incentivise the right behaviours in the right locations. This has the benefit of being able to target the incentives accurately and avoid any over incentivising due to the summation of DUoS and DSR charges. This method benefits from the simplicity of the core charging whilst maintaining the locational elements with limitations to the potential volatility. This could include mechanisms for constraint payments, as used at transmission level. However these would need to be linked to the connection charging methodology to prevent perverse incentives for the location of generation.

5 Discussion

This report has briefly highlighted the current methodologies used for network charging as well as some high level options for change.

It should also be noted that the manner of implementing changes, can be as important as the changes themselves. Changes can be brought through the basic code modifications or through a more holistic significant code review. Both have their pros and cons, whilst code modifications lack the breadth of coverage, their delivery is significantly more straightforward than an SCR.

In addition, any changes to charging at distribution level must be coordinated with wider industry changes. In such an interconnected industry changes at one level can have knock on impact to much wider stakeholders.

WPD acknowledges the importance of cost reflective tariffs. However our own stakeholder engagement work consistently shows that customers desire stability in their charges to match other long term investment decisions.

Since the immediate future is so uncertain, with major changes in the industry and unpredictable uptake of new low carbon technologies, it is likely that network congestion is likely to change significantly over the ED1 and ED2 periods. Hence highly cost reflective charges would suffer from volatility.

We therefore propose moving to simpler rather than more complex charging arrangements. This may be in the interim until the extent and pace of change is better understood. Any more complex and cost reflective methodology introduced today is likely to have unintended consequences as the UK energy system undergoes a significant transformation.

The concept we propose would be based on a long term fixed charging model with rebates for customers offering balancing services to the DSO. For example, customers electing to offer reactive power support, flexible response from generation/load or other ancillary services could receive a rebate. Some customers may be able to provide multiple services to the DSO in return for a larger rebate. By providing a straightforward financial benefit to customers actively providing services back to the DSO there is be a clear pathway and incentive participate. Such an arrangement would be welcomed by most customers for the stability in prices it would bring whilst encouraging them to access balancing services. Such stability is likely to lead to higher confidence of investors in the flexibility and energy market. As highlighted earlier the topic of network charging has now come to the fore, as such we expect the topics highlighted and many more to be discussed in the various industry groups looking at the topic such as Ofgem’s TCR looking into residual costs as well as the ENA’s Open Networks project.