21, rue d'Artois, F-75008 PARIS
http : //www.cigre.org

CIGRE US National Committee
2016 Grid of the Future Symposium

The Impacts of Distributed Energy Resources on Future Network Utility Tariff Structures

G. MCFADZEAN
S. WEATHERHEAD
TNEI Services Ltd
UK

P. TAYLOR
I. ALEXANDER
CEPA
UK

M. POLLITT
University of Cambridge
Judge Business School
UK

SUMMARY

The increasing uptake of Distributed Energy Resources (DERs) will lead to more flexible use and the operation of distribution networks. This will have an impact on distribution network costs and how different user groups can be expected to use the distribution system. To reflect these changes, network utilities will need to reform their tariff structures. The reform must meet two objectives: encourage DERs and flexibility where they can bring benefits to the system, and provide a fair and sustainable basis for network utilities to recover and allocate their costs between network user groups.

This paper sets out a framework for defining future network tariff structures which may be required in a more flexible electricity system. This framework explicitly distinguishes between tariff elements which could provide signals to network users, and elements which are required for cost recovery. It also distinguishes between long term (investment) timescales and short term (operational) timescales. Based on the options discussed, we set out a number of future tariff packages that could be implemented, and discuss some possible implementation issues.

We gratefully acknowledge ideas and contributions from Michael Pollitt's EPRG working paper 'Electricity Network Charging for Flexibility'.

KEYWORDS

Distributed Energy Resources, Flexibility, Network Tariffs, Long Run Marginal Costs, Cost Recovery, Net-metering, Demand Charges

gordon.mcfadzean@tnei.co.uk

Introduction

The continuing growth of Distributed Energy Resources (DERs), including Distributed Generation (DG), Energy Storage (ES) and flexible demand such as demand side response (DSR) will change the way in which distribution networks are used by customers and operated by utilities. In particular, these DERs will allow networks to be operated with greater flexibility, which will in turn allow for the connection of further electrified low carbon demand and embedded renewable generation.

As an example of the potential benefits of flexible DERs, a study for the UK's Committee on Climate Change (CCC) by Imperial College and NERA [2] noted that increasing system flexibility is a low-regret option for decarbonisation and could allow Great Britain (GB) to save £7.1 - £8.1bn per year, given a carbon intensity target of 50g /kWh. In its 2015 position paper [1], GB's energy regulator, the Office of Gas and Electricity Markets (Ofgem), defined flexibility as "*modifying generation and/or consumption patterns in reaction to an external signal (such as a change in price, or an electronic message) to provide a service within the energy system*". This could include shifting consumption to different periods of time, reducing demand at critical times (e.g. peak periods) or even increasing consumption when necessary.

Changes in the use and operation of electricity distribution networks, as the system becomes more flexible, will alter the fundamental nature of network costs. In addition, under existing tariff structures, the uptake of DERs could skew the allocation of infrastructure and system costs towards certain network user groups. Given the range of objectives that are typically applied when defining an optimal structure for electricity distribution tariffs (e.g. cost reflectivity, predictability and, in some jurisdictions, socially acceptable levels of price discrimination between different network user groups), the implication is that the existing basis of network utilities' tariff structures may now require reform.

This paper explores the impact which greater deployment of DERs and increasingly flexible electricity systems could have on existing distribution network cost arrangements and, therefore, the basis on which network tariff structures might need to be determined in the future.[1] It sets out a number of models for distribution network tariff structures. Each of these results in different systems for recovery of the fixed and sunk investment costs of the distribution system from network user groups, as well as different mechanisms for encouraging the provision of flexibility where it provides value to the system.

All electricity systems will face different circumstances, and so a 'one size fits all' model is unlikely to be appropriate across different jurisdictions. Therefore, the alternative models for future distribution tariff structure that are set out in this paper provide a range of options for utilities, policy makers and regulators to consider based on the unique conditions and objectives of their local industry.

Distribution Costs and Use of System Charges

When considering distribution network costs and use of system tariff structures, it is useful to draw a distinction between the behaviour of the utility and its customers over both long term (investment) timescales and short term (operational) timescales. Currently, in many countries, the distribution network utility makes very few decisions over operational timescales – instead, a network is passively designed and built over investment timescales to meet some worst case system stress conditions. Therefore the mechanisms which provide signals to users over operational timescales – e.g. to incentivize users to operate usefully in a flexible way – are often very simplistic. Instead, investment

[1] This paper considers issues associated with cost allocation, as determined through network utilities' tariff structure. It does not address how the growth of DERs might need to impact on how the wider regulatory (e.g. price control) framework which is used to set the total regulated costs and revenues network utilities are permitted to recover from their user customer bases.

in the network, network asset costs, and therefore the basis on which cost reflective network tariff structures are set, have largely been driven by peak demand conditions.

Many network utilities have therefore based their existing network tariff structures on their customers' use of the network at system peak, or a proxy of peak usage such as their net consumption throughout the year (which has historically had a close correlation with peak consumption). Often, Long Run Marginal Cost (LRMC) pricing principles, which are 'forward looking' (in that they consider future investment by the utility) will also be used as the underlying basis for cost allocation, to help to offer 'signals' to network users of the costs and benefits that their incremental use of the distribution system (e.g. by time of use) could have for the network's costs (generally cost reflective charging for distribution is confined to use related elements, as distance or location related elements are difficult to ensure are cost reflective in electricity distribution systems).[2]

In regulated distribution networks it is common for the structure of network tariffs to be set independently of price control allowances. In most jurisdictions, the price controls effectively set a cap on the allowed revenues network utilities are permitted to recover from their customer base. The allowed revenues are based on the network utilities' costs (plus incentive schemes etc). Part of these costs is 'variable', meaning it can increase or decrease due to customers' investment and operational decisions. However, a larger proportion of the allowed revenue relates to costs which are essentially 'fixed' over both the investment and operational timescales[3], and to costs which are 'sunk' (i.e. the utility's recovery of the historical investment in the network that was needed to provide the assets which customers can use today).

Whilst network tariffs can be structured using forward looking (LRMC based) principles, there is usually a gap between a LRMC tariff level (that can help promote efficiency of network use), and the allowed revenues the utility will need to recover in total to finance its activities. Stated formally, the utility's average cost will be higher than its marginal cost – one of the features that has traditionally meant that distribution network operators' have been considered a natural monopoly – and this gap must be addressed as part of an LRMC based charging system if the network utility is to maintain a sustainable and financeable business. Some utility's therefore 'scale' LRMC based tariffs to ensure allowed revenues are recovered. Others apply 'residual' tariffs for a similar purpose and some simply adopt simpler tariff structures focused only on cost recovery.

The Impact of DERs

Policy makers that want to encourage the uptake of DERs must consider whether current network charging arrangements will actually facilitate this and lead to flexibility.

Policy makers have traditionally focused on LRMC based tariff structures because they offer the opportunity to signal to users the cost and benefit impacts which their flexibility actions (e.g. time or location of use of system) may have on the network. Network tariffs which reflect the marginal costs of changing use of the network can help to guide users' investment and operational decisions, and therefore minimise overall system costs.

The challenge, however, is that the cost characteristics of electricity distribution networks mean that only a small proportion of a network utility's total allowed revenue relates to marginal cost based expenditure (<10%).[4] The remaining proportion is associated with the recovery of the network utility's

---

[2] However, in Great Britain, DNOs have recently introduced locational elements for use of system charges for access at the EHV level.

[3] For example, direct and indirect operating costs, non-load related network investments, network rates etc are unlikely to change significantly based on customer behaviour.

[4] For example, analysis of price control allowances for a GB DNO (Western Power Distribution) showed that only around 12% of allowed revenue related to active reinforcement of the network and the provision of

fixed and sunk costs (which will not vary with network use). If part of the network utility's charges are not fixed[5], and are instead based on net-metered usage then DERs – that can allow network users to reduce their metered consumption and, therefore, net use of the public electricity network – can allow those user groups to avoid contributing to the system's fixed and sunk costs.

Firstly, this may create concerns for the long term financial sustainability of network utilities if, in the absence of reforms to charging arrangements, an increasing proportion of the system's fixed and sunk costs have to be recovered from an increasingly small proportion of the user base (this has been referred to as the 'utility death spiral' in other contexts). Secondly, those user groups who do not, or cannot, invest in DERs will experience increasingly higher bills relative to those who can.

Finally, there is a risk the deployment of DERs is over incentivised as a consequence of network utilities' tariff structures. The flexibility which DERs offer has the potential to provide significant benefits for the electricity system. However, rather than creating efficient investment and operation of these technologies in a manner that is useful for the electricity system, user decision making may instead be driven by the incentive to use DERs to avoid contributing to the system's fixed and sunk costs – which by their very nature, at least in the short to medium term, cannot be avoided by society.

International Precedent and the Case for Reform

Concerns specifically around net metering and the 'utility death spiral' have led many utilities in the USA to introduce new demand charges. With such tariffs, some of the utilities revenue (including distribution costs) is recovered based on users' kW consumption during certain periods (e.g. system peak). According to The Brattle Group [3], 24 utilities in 14 states have introduced summer demand charges.[6] South Queensland in Australia is another example where kWh charges in an environment of rapid uptake of PV has had a radical impact on the incidence of network cost allocation between different network user groups and policy makers have as a result needed to investigate reforms. National Grid has recently begun to highlight similar issues in the UK [4].

Looking forward, with the uptake of DERs only expected to increase across a number of countries and regional electricity markets, network utilities' tariff structures will increasingly need to balance two objectives. On the one hand, tariffs can help to encourage DERs and flexibility where this can bring benefits to the system. On the other hand, tariffs need to create a fair and sustainable basis for network utilities' cost allocation between network user groups. One important principle is that whilst a flexible user may be able to easily avoid consuming power during system peak conditions (for example, through the use of batteries, embedded generation, DSR and other technologies), they may still derive value from firm network access across the rest of the year. If they derive benefit from the security which the 'option' of using the network provides, then they should not be able to completely avoid paying for the existence of that network.

Building Blocks of Future Tariff Models

Future network utilities' tariff structure will therefore need to be designed to ensure that they both (i) encourage (or at least do not act as a barrier to) the provision of flexibility where it can benefit the system and (ii) do not lead to very unequitable outcomes that benefit flexible users. To set out some of

---

connections. The remaining 88% of the revenue allowance was to recover these quasi-fixed costs and revenue contribution associated with the recovery of the network's sunk investment costs.

[5] If, for example, the basis of at least part of the tariff structure is kWh based across the year or kW based during expected time periods of peak demand.

[6] These demand charges have been criticised, e.g. by the Energy Freedom Coalition who state that they are complicated, unfair and discourage energy conservation and distributed generation. As they are based on consumption during system peak, although they may help to reduce the problem associated of recovering sunk investment costs from DERs such as storage of DSR, they may not mitigate the issue entirely. For example, in a given month, a DSR user may only have a peak demand of 600kW, even if they derived some benefit having the option to use up to 800 kW given the capacity of their connection.

the options for achieving these two objectives, we have established a network charging framework which distinguishes between (i) the signals for flexibility services which a network utility provides over both investment and operational planning timescales and (ii) the mechanisms by which the network utility ensures the recovery of the efficient costs which it incurs over both investment and operational timescales. This is set out in Table 1, along with some options which are described in more detail in the following subsections.

Table 1: Framework for Network Tariff Structures in a Flexible System

	Signals	Cost Recovery
Investment Timeframe	'Opt-in' (LRMC) Tariffs Contracted Tariffs Access/Connection Markets	Fixed Tariffs Use Based Tariffs Ramsey Pricing Tariffs
Operational Timeframe	'Opt-in' (Time of Use) Tariffs Contracted Tariffs Wholesale Markets	Fixed Tariffs Use Based Tariffs Ramsey Pricing Tariffs

As Table 1 suggests, it can be useful to think about network tariffs in terms of both the decisions which users make over operational timescales (e.g. across trading periods) and over investment timescales (e.g. across whole project lifecycles). In general, operational decisions will likely affect the time-varying impacts which a user has on the network (e.g. import and export profiles), where as investment decisions will affect the locational impacts their use has on the network (e.g. point of connection).

In practice, there are interactions between the operational and investment behaviours of the utility and its customers. However, in principle, it could be appropriate to have separate tariff mechanisms for recovery of forward looking and operational costs and any residual that is then left for the network utility to recover its total costs.

Three options by which the network utility could provide **signals** for flexibility to its user groups are set out below. These signals could be used to set a forward looking element of a tariff (or for more direct procurement of certain flexibility services):

- **'Opt-in' Tariffs:** This describes situations where a network utility sets tariffs which passively signal to the user that they should behave in certain ways (over both operational and investment timeframes). These tariffs would likely be based on modelled costs and benefits and are, therefore, price-based. Critically, there is no commitment from users that they will exhibit the required behaviour under this type of tariff system. If set based on LRMC or other cost reflective principles, then it is crucial that these tariffs would be levied in a way that does not allow particular user groups to avoid contributing to fixed and sunk costs of the system where they benefit from access to that system. (e.g. not levied on net kWh consumption).
- **Contracted Tariffs:** These would be set similarly to the opt-in tariffs; however, the user would commit via a contract to behaving in a certain way. The network utility might have

direct active control over/of the users' behaviour, or could indirectly control the user via commercial mechanisms (e.g. penalties). For example, this option could see the utility entering into long term contracts with users for network access over long term investment timescales (such as a demand side management (DSM) or generation side management (GSM) agreement). This could be based on the LRMC of connecting, taking into account a deep connection boundary. For some users, the utility could offer contractual clauses which would require certain types of flexible behaviour from the user over operational timescales, such as reducing demand at peak times, provision of reactive power, etc.

- **Markets:** This describes schemes where both the utility and its customers actively provide signals to each other for certain types of behaviour. In many countries, markets already exist in operational timescales (e.g. wholesale markets, ancillary services markets, balancing mechanisms). In the future, one can envisage local distribution markets for flexibility which allows the utility to procure required flexibility services from DERs. The use of Locational Marginal Pricing (LMP) systems could even be extended to the distribution system (supporting by physical or financial distribution rights sold by the utility when it invests over the investment timescale for the purposes of reinforcement to allow network access). Under certain options, a market based approach would effectively take the signalling issue for flexibility outside of network tariff decisions.

Three options for distribution cost recovery are discussed below. These principles could be used to set 'residual' tariffs or used as the basis for 'scaling' other components of network utilities' network tariffs.

- **Fixed Tariffs:** For some users (e.g. domestic consumers) fixed charges may be the most appropriate way to recover sunk and fixed costs (e.g. if little data is available and it is more difficult to engage directly with a large volume of customers).
- **Use Based Tariffs:** Residual costs could be levied on users based on their relative usage of the distribution network. For example, this could be based on gross MWh consumption or contracted import/export access capacity rather than net metered consumption.[7]
- **Ramsey Pricing Tariffs:** Ramsey pricing principles would be allocated to individual network users inversely to their expected price elasticity. In theory, this is the most economically efficient way to recover taxes or monopoly costs.

The cost recovery method should be structured such that it does not distort behaviour (i.e. users cannot contributing to sunk and fixed costs by using DERs), and should meet any requirements for societal fairness.

Possible Future Tariff Packages

There are many ways in which the options set out above could be combined to produce a range of different tariff 'packages' which a network utility could implement to ensure efficient signals and equitable cost recovery is achieved.

For example, a package that would look very similar to the status quo arrangements for distribution charging in some countries today, might involve using ex-ante marginal cost based signals through Opt-in LRMC and time of use tariffs to signal the costs and benefits of using the system at different locations and times of the year. Cost recovery might then be achieved through a combination of fixed charges and *capacity (kW)* use-based charges.

A more market, economic efficiency based, package might involve the network utility or a distribution system operator (DSO) applying an LMP type system with local access right contracts (e.g. Financial Distribution Rights, Physical Distribution Rights, Distribution Flow Gate Rights) providing cost based

[7] This could even be done based on the comparative use of the network by different customers (e.g. based on load flow modelling).

signals of the impact of network use across both operational and investment timescales. Any residual network costs might then be recovered by the network utility applying Ramsey pricing principles (for example, applying progressive inclining block charges to gross energy consumption).

Another package might see network utilities' default tariffs structured primarily to ensure a sustainable and equitable allocation of total network costs between network user groups. The utility would then offer deviations from those default tariffs to users with DERs and other providers of flexibility for 'contractually useful' services that the network utility can accommodate into its actual operational and investment planning decisions.[8]

A key point that emerges from all these network utility tariff systems is that in future charging decisions will need to be made holistically considering a range of relevant objectives and potential impacts from DERs. The considerations include potential interactions with future investment planning frameworks and the potential for more active network management using DERs.

Conclusions and implementation

This short paper has briefly discussed some of the key issues that the uptake of DERs creates for future charging decisions for distribution network utilities and policy makers. It has also set out a framework for how these charging decisions could be made in the future.

Where the uptake of DERs leads to reform of network tariffing systems, policy makers and network utilities must also grapple with how to design transitional arrangements. Network charges will need to evolve to facilitate the flexibility actions that the system needs, but this must be balanced with the need to reduce risk and uncertainty for users. Existing users may believe that they have certain property right for the terms on which they access the electricity networks today. Therefore, some sort of 'grandfathering' arrangements for existing Customers may be required.

Network tariffs also only comprise a part of the final bill that many network users, in particular, end consumers, face for their use of the electricity system. Policy makers will need to consider how network tariff structures sit within retail pricing offers and structures, and how these costs are ultimately passed on to final consumers.

Acknowledgments

We gratefully acknowledge ideas and contributions from Michael Pollitt's EPRG working paper 'Electricity Network Charging for Flexibility' [5].

BIBLIOGRAPHY

[1] 'Making the electricity system more flexible and delivering the benefits for consumers', (Ofgem), September 2015

[2] 'Value of Flexibility in a Decarbonised Grid and System Externalities of Low-Carbon Generation Technologies', (Imperial College London, NERA Econmic Consulting), October 2015

[3] Ryan Hledik, 'The Top 10 Questions about Demand Charges', (The Brattle Group), May 2015, accessed via http://www.brattle.com/system/publications/pdfs/000/005/171/original/The_Top_10_Questions_about_Demand_Charges.pdf?1431628604 [29/07/2016]

[8] This type of tariff structure could be used to signal network costs as well as benefits (avoided costs). For example, where a network user triggers a reinforcement, and they are unwilling to enter into an interruptible contract, they would pay a premium on top of the default tariff. This would be determined based on the cost of the triggered reinforcement.

[4] 'Fair and sustainable charging', (National Grid Connecting), July 2016, accessed via http://www.nationalgridconnecting.com/a-fair-and-sustainable-approach-to-charging/
[5] M. G. Pollitt, 'Electricity Network Charging for Flexbility', University of Cambridge Energy Policy Research Group, EPRG Working Paper 1623, Cambridge Working Paper in Economics 1656, Sept 2016,