New Development in Distribution Network Pricing for Revenue Recovery in the Great Britain

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***Abstract*—This paper presents the latest development in (Extra-high Voltage) EHV network pricing in the UK. It introduces the amendment made to Long-run Incremental Cost (LRIC) pricing and Forward Cost Pricing (FCP) as suggested to overcome their particular disadvantages appearing in practice. Particularly, this paper investigates three scaling approaches examined and considered by Distribution Network Operators (DNOs) for revenue reconciliation. A small system is utilized to demonstrate the calculation of the three approaches and the final unrecovered revenue.**

***Index Terms*—Distribution network charges, Long-run incremental cost pricing, Forward cost pricing, Revenue reconciliation**

I. Introduction

IN 2005, the UK's gas and electricity markets watchdog – the Office of Gas and Electricity Markets (Ofgem) commissioned the University of Bath (UoB) to investigate the potential benefits of introduction new charging methodologies in distribution networks and their efficiency in encouraging economic distribution network development [1]. Since then, the design and research of charging models in the UK has undergone dramatic progress. Network pricing is utilized to price network customers according to their use-of-system (UoS) to recover the costs from Distribution Network Operators (DNOs), such as direct operating costs, indirect costs, network work rates and transmission exit charges, etc.

Prior to 2007, all 7 DNO in the UK used the Distribution Reinforcement Model (DRM) to charge network users for their use of distribution networks, but their methodology implementations differed widely. The DRM was proposed by Electricity Council in the UK in 1982 as an approach for cost allocation for DNOs. Since then, DRM has been the foundation for distribution tariff setting in England and Wales [2]. Ofgem has been keening to reforming the DRM model for one key reason is that it generates a flat charge at each voltage level and offers no locational incentivizes to guide distributed generators to locate closer to load centers apart from differentiating voltage levels. The other issue is with the divergence in the implementation of DRM pricing among the 7 DNOs, which makes it hard for suppliers to understand and interpret each DNO's implementation [3].

Two economic charging methodologies emerged as the preferred candidates by the industry for the development of common distribution charging methodologies – Long-run Incremental Cost (LRIC) Pricing and Forward Cost Pricing (FCP). The LRIC model was originally proposed by UoB in conjunction with Ofgem and Western Power Distribution (WPD)[4]. The FCP model was initially developed by Scottish and Southern (SSE), Central Networks (CN), and Scottish Power (SP) for pricing users [5, 6]. They are considered by the industry as well as Ofgem as the best available approaches to achieve the high level charging principles, cost-reflectivity, simplicity, and predictability. Due to the complexity of the two economic charging methodologies, however, it is agreed by the industry that the current DRM pricing model is retained for HV/LV network charging, whereas the two charging models are only applicable for EHV networks. Ofgem allows DNOs to choose one from the two models to implement [3].

Thus, from 2008 onwards, the GB distribution pricing reform has been running in two fronts. One is further development of the cost-reflective and forward looking distribution charging methodologies that can encourage the efficiency use of networks. The other is to achieve the commonality in network charging as far as possible across all 7 DNOs so as to reduce the effort suppliers endure in developing tariffs for end consumers.

In practice, however, many problems appeared when implementing the two approaches. Thus, Ofgem has allowed all DNOs to delay the submission of their approaches to 1 April 2011 and implementation in 1 April 2012. This decision gives the DNOs more time to review the issues concerning their implementation, to justify their level of charges, to conduct further consultancy with stakeholders and to make customers understand their charges. At all times, the 7 DNOs have been trying to improve their pricing model and scaling for revenue reconciliation.

This paper seeks to report the recent progress that the industry has made to the two distribution pricing models proposed by DNOs. Particularly, it presents the scaling approaches examined and considered by DNOs for their revenue reconciliation. An intensive demonstration and analysis of three scale methods: traditional fixed adder, voltage level adder and site specific adder is conducted on a small test system.

The rest of the paper is organized as follows: Section II gives a brief introduction to the LRIC and FCP models and compares them. In Section III, the new amendment for them is introduced. Section IV reports and demonstrate the three scaling approaches. Section V concludes this paper.

II. INTRODUCTION OF LRIC AND FCP

The 7 DNOs in the UK agreed on achieving unity in HV/LV network charges, but they differ in which of the two preferred EHV charging methodologies would be better in meeting the high level charging objectives. Rather than going to competition commission and risking of delaying the distribution pricing project, Ofgem allowed the GB DNOs to choose one of the two preferred charging methodologies. The industry is therefore working on the two common EHV charging methodologies and aiming to achieve commonality.

A. Long-run Incremental Cost Pricing

The LRIC model works by examining the changes in components' future reinforcement horizons affected by nodal injections and translating the changes into the variation of components' present value of future reinforcement. Components' investment horizons are decided by their present loading conditions, their spare capacity and the perceived load growth rate [4]. The final charge for a busbar is the summation of the price from all its supporting components calculated under a given discount rate.

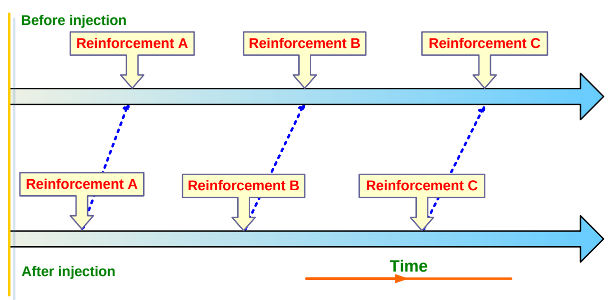

Fig.1. The principle of long-run incremental cost pricing [7].

Fig. 1 illustrates the basic concept behind LRIC and its rough implementation steps are summarized as [4]

1) To work out components' original reinforcement horizons without any injections. Components' original loading levels are assessed with power flow analysis, which are then submitted into the formulas for determining their reinforcement horizons.

2) To determine components' new reinforcement horizons with injections. They are determined by examining how nodal injections would affect their loading levels with incremental flow analysis and submitting into the formulas for assessing horizons.

3) To assess nodal unit price. The charge for a nodal is all the incremental costs incurred from its supporting components, which are then discounted back into as present value of future reinforcement.

B. Forward Cost Pricing

With FCP pricing, each license distribution service area network is broken down into a number of 'Network Groups', such that each group is part of a distribution system that is not connected to adjacent Groups at the same voltage level under normal operating conditions [2]. By contrast, FCP model treats demand and generation separately to derive charges.

FCP demand price is calculated by assessing network reinforcement cost to support a maximum of 15% demand increment for each network group over the next 10 years rather than assets' lifetime [8]. The demand growth is from the forecast in each network group. Potential reinforcement cost is calculated and averaged at each voltage level within the same network group such that the total revenue recovered equals to the forecasted reinforcement cost plus a certain level of investment return. Fig.2 depicts its demand pricing concept.

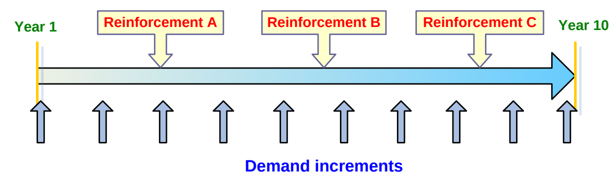

Fig. 2. FCP charging for demand [7].

FCP generation price consists of two parts: reinforcement cost and generation benefit. Reinforcement cost is evaluated by aggregating the cost of the total present value of the reinforcement project required to accommodate potential generators over 10 years, as depicted in Fig.3. The size of the test generator for each voltage level is 85th percentile of the existing generation size at that level [9]. Generation benefit comes because generators can reduce the needed reinforcement caused by demand increase. The benefit on a distribution network at each voltage level is set equal to the corresponding demand costs, scaled down by a factor that reflects the reliability of the generation technology suggested in Engineering Recommendation P2/6 (ER P2/6) [5]. Total FCP generation charge is generation cost minus generation benefit.

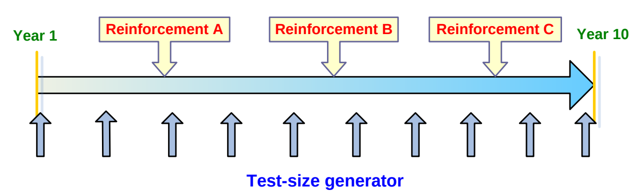

Fig.3. FCP charging for generation[7].

FCP charges within the network group are the same for all customers connected to the group [2].

By comparison of the two approaches, the granularity of the locational message[10], the strength of the message [10], and complexity and other features of the two approaches are summarized in Table I.

It is hard to directly tell which one is better over the other, as they have particular advantages of advantages. Generally, LRIC offers the strongest locatonal signals, reflecting both the distance and the degree of utilization in network assets. FCP offers weak locational message, this is both in terms of magnitude of charges and granularity of charges. In terms complexity, LRIC requires AC power flows and contingency analyses, but treat generation and demand the same. FCP represents the most complicated charging model, which arises from the different treatment between generation and demand.

TABLE I
THE COMPARISON AND CONTRAST OF LRIC AND FCP

	LRIC	FCP
Price granularity	Node	Network group
Reinforcement requirements	Change in net present value of reinforcements due to tinny injections	Cost of reinforcements in 10 years period
Demand growth	Fixed at 1% or chosen based on load prediction	Derived from LTDS
Charge for demand	Notional asset costs to accommodate the potential demand growth	Investment costs in 10 years averaged at each GSP group
Charge for generation	Change in net present value of reinforcements due to tinny minus injection	Summation of generation cost and demand benefits
Locational signal type	Strong and nodal	Weak and group
Treatment of network security	N-1 and N-2 contingencies	N-1 and N-2 contingencies
Simplicity	AC load flow and contingency analysis	AC load flow and contingency analysis; treat demand and generation separately

III. NEW PROGRESS IN LRIC AND FCP

In order to overcome the shortcomings of the two models some improvements have been made to the two approaches proposed by industry.

A. Improvement of Long-run Incremental Cost Pricing

One major problem with the LRIC model is that in some particular cases, extremely large contingency factors of network components might be obtained. Once they are utilized to reshape components' maximum available capacity to accommodate N-1 and N-2 contingencies [11, 12], their equivalent utilization levels would be escalated extremely high. In this case, even a small injection would cause great change in their reinforcement horizons, and consequently lead to high charges. The reason behind is that these components are lightly utilized in normal conditions, but greatly loaded during network contingencies. Therefore, their contingency factors, which are calculated with their maximum contingency flows with their normal case flows, become rather big. Hence, it is proposed that "sense-checking" needs to be done on the power flow derived from the application of contingency factors beforehand. Particularly, thresholds can be employed to cap network contingency factors [10].

Another issue with the LRIC model is that some branches might be over recovered. It is because that the model would generate extremely high charges in specific cases that perceived load grow rates are small branches' utilization levels are high. The revenue recovered alone from the LRIC charges would overpass the total allowed revenue. In order to avoid such instances, it has been suggested that scaling factors be introduced for the branches with excessive recovery so that the recovered revenue will not overpass the annuitized costs of the components [10].

B. Improvement of Forward Cost Pricing

The trickiest issue with FCP is pricing for generation. In order to work out the results, it employs a test generator to examine how much investment needed to accommodate the development in generation. The selection of the sizes of test generators has a significant impact on the determination of network investment and consequently the final charges. As for FCP generation price, it is quite sensitive to the size of test generator and the forecasted new generation. If improperly handled, the derived charges would become misleading, unable to truly reflect the UoS by generation. Therefore, the industry advised that the testing of the impact of generation across networks needs to be increased to create a more rigorous and reflective generation testing regime. In addition, it is also suggested that "sense-checking for the test size generators (TSGs)" be done to avoid circumstance that over estimation of future generation appears. A threshold can be used to control the TSGs [10].

IV. NEW IMPROVEMENT IN SCALING

Normally, neither incremental nor marginal charges can recover the revenue allowed for DNOs. Revenue reconciliation process, i.e., scaling is used to adjust the charges to match the revenue target and allocate the difference (shortfall or excess) among network users. The mechanisms used by DNOs are equally important due to the fact that in practice, a large proportion of their revenue may be recovered through such scaling mechanism and it may have a significant impact on the relative level of nodal tariffs.

There are two commonly adopted revenue reconciliation approaches to adjust the nodal prices, namely "fixed adder" and "fixed multiplier" [13]. The fixed adder method adds/subtracts a constant amount to/from the nodal charges to make up for the revenue shortfall/surplus. The multiplier method scales the nodal charges by a constant factor corresponding to the ratio of the target revenue to the recovered revenue [14]. These two approaches are not new, but the fixed adder approach is favored by Ofgem since it can preserve the internal economic signals of charges. The recent progress in the improvement of scaling targets at amending fixed adder to incorporate more planning concerns to properly allocate the unrecovered revenue among customers. The examined and considered approaches by the DNOs are traditional fixed adder, voltage level adder and site specific adder.

The demonstration and comparison of the three scaling methods is carried out on the small system given in Fig.4. Its all commercial and technical information is given in Table I. It is assumed that the total allowed revenue is £1million. The recovered revenue from network charge is calculated as £0.4 million. Therefore, £0.6million needs to be recovered through scaling, which is split between customers according to their capacity.

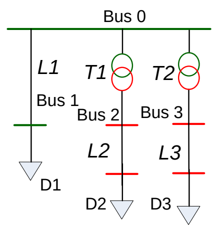

Fig.4. A small illustration example

TABLE I
INFORMATION OF THE SMALL SYSTEM [10]

Customer	132 kV customer (D1)	33 kV customer 1 (D2)	33 kV customer 2 (D3)
Capacity	50,000kVA	10,000kVA	40,000kVA
Charge	£2/kVA/year	£10/kVA/year	£5/kVA/year
Recovery from charge	£100,000	£100,000	£200,000
Notional assets at 132 kV	£2 million	£5 million	£3 million
Notional assets at 33 kV	Not used	£7 million	£3 million

A. Traditional Fixed adder

As explained previously, this method generates a uniform fixed adder in £/kVA/yr for scaling in a DNO’s territory. It does not use assets but works on an aggregated network use, calculated based on the percentage of agreed import capacity.

For this simple example, a fixed adder of £6kVA/yr is derived, which comes from by dividing the total unrecovered revenue of £0.6 million with the total demand capacity of 100,000kVA. By applying this fixed adder to all customers in the system, the following data can be obtained, summarized in Table II.

Table II
REVENUE RECOVERED THROUGH TRADITIONAL FIXED ADDER

Customer	132 kV customer (D1)	33 kV customer 1 (D2)	33 kV customer 2 (D3)
Capacity	50,000kVA	10,000kVA	40,000kVA
Recovery from charge	£100,000	£100,000	£200,000
Scaling	£300,000	£600,000	£240,000
Total recovery	£400,000	£160,000	£440,000

B. Voltage Level Adder

This scaling approach also does not use network assets, but instead, it use a measure of network utilized at each voltage level by customers to work out the specific adders at each level.

TABLE III
REVENUE RECOVERED THROUGH VOLTAGE LEVEL ADDER

Customer	132 kV customer (D1)	33 kV customer 1 (D2)	33 kV customer 2 (D3)
Capacity	50,000kVA	10,000kVA	40,000kVA
Recovery from charge	£100,000	£100,000	£200,000
Scaling	£150,000	£90,000	£360,000
Total recovery	£250,000	£190,000	£560,000

This example has two voltage levels: 132 kV and 33 kV, each supporting a demand of 100,000kVA and 50,000kVA respectively. The total notional asset cost at both 132kV level and 33 kV are £10million, and hence the unrecovered revenue should be split equally between the two voltage levels equally. The fixed at 132 kV level is derived by dividing of the total unrecovered at 132 kV level (£0.3million) with the total demand capacity it supports (100kVA), which gives £3/kVA/yr. Similarly, the fixed adder at 33 kV level is calculated as £6kVA/yr. The total revenue recovered from scaling is calculated though applying the two voltage level adders at each voltage level to the three customers. As noted, the two customers at 33 kV level use both 132 kV and 33 kV components, and hence they need to pay the revenue from the scaling at both levels. The revenue recovered from the three customers is given in Table III.

C. Site Specific Adder

This scaling approach allocates the unrecovered revenue based on the level of assets used by each demand customers. Instead of assuming the average use of assets at each network level by each customer, it utilizes a “network use factor” for each customer to measure their use of system. The factor of each component for a particular customer can be obtained through power flow analysis.

TABLE IV
REVENUE RECOVERED THROUGH SITE SPECIFIC ADDER

Customer	132 kV customer (D1)	33 kV customer 1 (D2)	33 kV customer 2 (D3)
Capacity	50,000kVA	10,000kVA	40,000kVA
Recovery from charge	£100,000	£100,000	£200,000
Scaling	£150,000	£90,000	£360,000
Total recovery	£250,000	£190,000	£560,000

In this example, L1 is solely used by D1, and therefore its use factor is 1, giving a fixed adder of £1.2/kV/yr, which is calculated by allocation the unrecovered revenue allocates to the component, coming to £0.06 million and then dividing with the demand capacity of 50,000kVA. Similarly, T1 and L2 are only used by D2, and T2 and L3 only support D3, which will eventually produce network use factors of 1 for all four component. The fixed adders of these components for the two customers can be obtained in the same way. The finally calculated recovered revenue is summarized in Table IV.

If a component is utilized by more than one customer, the site specific adder of a component for particular customers will be smaller than 1, which can be computed by running power flow analysis to examine how the component is utilized by the customers.

As can be seen from the previous three tables, the three scaling methods generate rather different recovery from the three customers. Whatever scaling approaches the DNOs choose, they should: 1) recover a fair allocation of allowed revenues from users; 2) should preserve forward-looking cost signals from LRIC/FCP; 3) the final charges after scaling should be cost-reflective and justifiable [10, 15]. Therefore, DNOs need to justify and test their decision of selection in line with the three targets. Due to approaching of submitting their choice, the DNOs are now still on the track to make progress.

V. Conclusion

This paper has presented the recent development in distribution pricing reform in the UK. It highlights the shorting comings with the current distribution pricing and the reported the improvement suggested by the industry. In addition, this paper also conducted an intensive comparison between LRIC and FCP from different aspects. It also reported three scaling approaches considered by DNOs for allocating unrecovered revenue. The demonstration of the three models was carried out on a simple system, which is qualified for illustration purposes. It is hard to conclude which scaling approach is more preferable, but they need to comply with the targets of revenue reconciliation.

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VII. Biographies

Chenghong Gu (S'09) was born in Anhui province, China. He received his Master degree in electrical engineering from Shanghai Jiao Tong University, Shanghai, China, in 2007. In 2010, he received his Ph.D. in Electrical Engineering from University of Bath, U.K. His major research is in the area of power system economics and planning.

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