Centre for Distributed Generation and Sustainable Electrical Energy

Framework and Methodology for Pricing of Distribution Networks with Distributed Generation

A report to OFGEM

by

Professor Goran Strbac and Dr Joseph Mutale

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Content

Glossary of terms

CHP	Combined Heat and Power
CI	Customer Interruptions
CML	Customer Minutes Lost
DD	Demand dominated
DG	Distributed Generation
DNO	Distribution Network Operator
DRM	Distribution Reinforcement Model
DUoS	Distribution Use of System
ER	Engineering Recommendation
GD	Generator dominated
GS	Guaranteed Standard
ICRP	Incremental Cost Related Pricing
IIP	Information and Incentives Project
LAF	Loss Adjustment Factor
LV	Low Voltage
MV	Medium Voltage
MLC	Marginal Loss Coefficient
NGT	National Grid Transco
OS	Overall Standards
SRMC	Short Run Marginal Cost
WSC	Worst Served Customers

Tables

Figures

Executive summary

This report discusses the objectives of distribution network pricing and presents a detailed exposition of network cost drivers. A pricing methodology based on the forward looking network investment cost is presented and discussed. A set of key policy questions posed by Ofgem in the context of developing a new DUoS charging methodology for distribution networks with distributed generation is addressed and recommendations for further work outlined.

Network pricing objectives

The primary objective of network pricing is to ensure economic efficiency (cost reflectivity). In the context of electrical power distribution systems, economic efficiency is concerned with sending price signals to users of the network with respect to the costs the users impose on network operation and/or development. This will ensure that in the short-term, the system is efficiently operated and that, in the long-term, it follows the path of least cost development (efficient investment). In the context of network operation and expansion, this requires some form of coordination between generation and network development as the optimisation of the network in isolation from generation would almost certainly not meet the above objective. Historically, vertical integration of conventional utilities seemed necessary for a sufficient level of coordination to be achieved. On the other hand, in the competitive environment, the necessary coordination of investing in generation and network assets is to be achieved through efficient network pricing mechanisms.

Economic efficiency is achieved by sending cost reflective price signals to users of the network so as to influence their decisions with regard to (a) location in the network and (b) patterns of network use and (c) signal need for and location of new distribution network investments, i.e., encourage efficient network investment and discourage over-investment. Network pricing based on future network development costs is the primary focus of this report[1].

Because network pricing is about influencing future behaviour, the investment costs that are relevant in the determination of efficient network use of system charges are *future network expansion costs* rather than present or past network costs.

Apart from the economic efficiency objective, network prices must also enable Distribution Network Operators (DNOs) to recover allowed revenues. Ideally network prices should be reasonably stable and predictable. Furthermore, determination of network prices must be transparent, auditable and the pricing regime must be practical to implement. This report discusses the interaction between these objectives highlighting the key challenge of striking the right balance between tariff complexity and the ability to fulfil key pricing objectives.

Linkage between network pricing and investment drivers and planning

Given that one of the principal objectives of network pricing is to send signals to users of the network regarding the costs they impose on network development, it is necessary to first establish future network investment costs. Future network investments and the associated costs are driven by the network design (planning) process. There is therefore a close link between *network pricing* and *network design (planning):* network design, in

[1] In addition, a method for cost reflective allocation of losses is also discussed.

a simplified form, is in fact a key input to network pricing. In the context of the UK distribution, network design is driven by:

(i) the need to satisfy network design standards (security and safety standards) and

(ii) a set of incentive mechanisms within the regulatory framework that may influence further investment (quality of supply, losses and incentives to connect DG).

All the drivers of future network costs should, in principle, be included in the determination of network prices although in practice the choice of which investment drivers will be included in the process is likely to be based on the materiality of the individual cost driver and the objectives of the pricing exercise.

In the future, the development of *active* network management may become important, as generators could opt to be constrained off during periods of reduced network availability may benefit from lower connection and/or DUoS charges.

Proposed network pricing method

In order to demonstrate the basic principles of the proposed network pricing methodology, in this report network design (planning) was assumed to be primarily driven by network security standards, i.e. the future costs are driven by network security considerations. However the proposed pricing framework allows other cost drivers to be included as appropriate (while balancing tariff complexity against cost reflectivity).

Given the network design philosophy (driven by security), the capacity of individual network circuits (lines and transformers) is determined by considering two critical conditions[2]:

(i) Maximum load and secure generation output[3] (for demand driven design)

(ii) Minimum load and maximum generation conditions (for generation driven design)

Clearly, only one of these conditions will be relevant for the design of each circuit in turn.

Economically efficient network prices are computed on the basis of marginal cost pricing principles, i.e. by considering the marginal impact of each user on network costs. The type of user (demand or generator) and the pattern of network use are key determinants of the impact of individual users on the network costs. In accordance with the marginal costing approach, the use of the individual plant items, such as lines and transformers, is charged only during the period of maximum loading of the plant under consideration.

Each piece of distribution plant, during its maximum loading can hence be characterised as being either demand dominated (design driven by *maximum* demand – secure generation contribution) or generation dominated (design driven by minimum demand-*maximum* generation conditions), depending on which of the two conditions is *critical* for its design. In case of a *radial* network this can also be determined by the direction of the *critical* flow: if the direction of the critical flow through a particular plant is downstream, i.e. from a higher voltage level towards a lower voltage level, the plant concerned is characterised as being demand dominated. The opposite is true for the generation-dominated loading of the plant.

[2] This is determined by running a load flow for each of these two conditions, used to establish the critical flow for each of the individual network circuits.

[3] Contribution that various generation technologies can make to network security will be defined in Engineering Recommendations P2/6, currently under consultation.

It is important to note that these two conditions occur in different times (e.g. maximum load and secure generation is usually associated with *winter peak*, while maximum generation- minimum demand condition is usually associated with *summer troughs*). This gives rise to time of use feature of the proposed pricing methodology.

Since generators and demand have opposite effects on the plant loading during the period of critical loading of the plant, both positive and negative charges will be present. Users that tend to reduce the loading of the plant during this period will be rewarded for the use of the network. In case of a demand dominated plant downstream generators get paid, while downstream demand pays for the use of the plant. Similarly, if the plant is generation dominated, demand gets paid, while the generators pay for the use of the plant (both charges and rewards are cost reflective). On the other hand, charges outside of the period of maximum plant loading are zero since the incremental change in plant loading has no impact on critical loading and hence does not impose any capacity related cost.

The proposed pricing method, for a given future demand and generation locations and profiles, determines the critical loading for each individual plant item in the entire distribution network. It is important to note that the above analysis includes consideration circuit outages at each voltage level as appropriate, which is consistent with the network planning process.

One of the key features of the proposed methodology is that positive and negative charges apply in different periods (times). For example, a generator may be rewarded for the use of *one* plant during times of maximum loading being driven by demand customers (such as winter daytime), but may be charged for the use of *another* plant during the period of maximum generation and minimum load (such as summer nights), if the plant design is driven by generation.

Therefore for a plant that is characterised as demand dominated, positive demand charges will be based on maximum demand, while negative generation charges applied will be based on the contribution that the generator makes to network security[4]. On the other hand, for a plant that is characterised as generation dominated, positive generation charges will be based on maximum generation output, while negative demand charges will be based on minimum demand condition.

We demonstrated that the cost reflective (efficient) network prices will always recover the cost of the *reference* network (this is the network in which all plant items have the capacities equal to their critical loading). Given that the allowable revenue will be different to the cost of reference network, *revenue reconciliation* will need to be carried out. Two alternative revenue reconciliation approaches are identified and discussed.

The philosophy of the concept is introduced by the aid of an example on which the main features of the approach are illustrated and discussed. Furthermore, the example is used to illustrate how the proposed methodology would work in practice and location specific, time of use tariffs are derived.

Given that the magnitude of electricity losses in distribution networks is significant, it may be appropriate to allocate losses efficiently whilst also recognising the impact of power factor on losses. This feature could be easily added to the described investment based pricing, and a brief description of an efficient loss allocation scheme is presented.

[4] Note that such cost reflective network pricing methodology could also provide a mechanism for rewarding generators for the contribution made to network security.

Given that the significant proportion of losses is in low voltage networks, this may be particularly interesting in the context of domestic CHP.

Recommendations for future work

A number of issues have been identified that may benefit from further evaluation before a proposal for a new distribution network pricing methodology is finalised. These could include:

- The materiality of individual network cost drivers and assessment of the benefits of including these in network pricing.
- The time horizons for estimation of future demand and generation profiles that are necessary to evaluate future network costs and use of system charges.
- The trade off between the complexity of tariff evaluation and the granularity of the tariff structure, including the appropriate balance between tariff stability (and predictability) and cost reflectivity.
- Access arrangements for DG, i.e. firmness of access of DG to distribution system, given that ER P2/5 is centered on network security from the perspective of demand, and does not explicitly deal with the level of availability of the network provided to generators. This could include an analysis of the compatibility of distribution and transmission practices in this context.
- Appropriateness of including mechanisms of allocation of network losses (and constraints through active network management) in network pricing, while recognising the impact of power factor.
- The features of alternative revenue reconciliation methods in practice (e.g. shifting or scaling of network prices).
- The features of energy and capacity based tariffs including duration of time-of-use periods etc.
- The impact of alternative network pricing approaches on future network expenditure (impact assessment of introducing new tariff arrangements).

1. Introduction

1.1 In order to deliver low long-term electricity prices to consumers of electricity, and consequently the best deal to society as a whole, the electricity industry has to ensure that, in the short-term, the system is efficiently operated and that, in the long-term, it follows the path of least cost development (efficient investment).

1.2 In the specific context of operation and expansion of transmission and distribution networks with central and distributed generation respectively, this requires a coordinated approach to optimising generation and network operation and development, as the optimisation of the network in isolation from generation would almost certainly not meet the above objective. Historically, vertical integration of conventional utilities seemed necessary for a sufficient level of coordination to be achieved. In a competitive environment this coordination needs to be achieved via appropriately designed commercial mechanisms.

1.3 One of the features of the introduction of competition in the power industry is the separation of generation and supply from network activities, in order to ensure that an open and non-discriminatory access to the energy market is enabled. In this environment, the use of network services becomes the key for achieving both efficient operation and least-cost system development of the entire system. The coordination of investing in generation and network investment should be achieved through efficient network pricing mechanisms.

1.4 In relation to government targets for renewable generation and CHP, a significant amount of distributed generation (DG) is expected to be connected to distribution networks. This will require the development of network access rights for distributed generation on non-discriminatory and transparent terms, recognising the cost and benefits that DG may create in terms of the impact on system security, the need for network reinforcement, network losses etc.

1.5 Clearly, if network pricing is not efficient, this could (i) adversely impact distributed generation deployment rates (ii) increase the cost of network investment required to accommodate such generation and (iii) distort competitiveness among generators of different sizes and technologies.

1.6 The proposed move from a deep to a shallow connection charge policy is aimed at addressing concerns associated with deployment rates. As the issues associated with the structure of charges for connection and use of distribution systems cannot be considered in isolation, the recent initiative of moving to shallower connection charge policy opens up the question of designing a new DUoS (distribution use of system) charging methodology for systems with DG.

1.7 The development of economically efficient DUoS will facilitate the cost effective integration of distributed generation in distribution networks.

Aims and objectives

1.8 The aims and objectives of this work were to:

- Set out the fundamental objectives of network pricing in a competitive environment including a discussion on the meaning and importance of each of the objectives as well as their interaction
- Undertake a review of investment cost drivers such as security constraints, fault levels, network losses etc, and discuss short and long term economic efficiency.
- Provide a critique of the principal approaches that could be applied to electricity network pricing highlighting their strengths and shortcomings in the context of satisfying the key network pricing objectives.
- Propose a methodology for determining distribution use of system charges explaining how the proposed methodology satisfies the primary objectives of network pricing.
- Discuss the practical implementation of the proposed methodology including transactional and transitional issues.

Report outline

The report is organised as follows:

1.9 Section 2 sets the primary objectives of network pricing in a competitive environment including a discussion on the meaning and importance of each of the objectives as well as their interaction.

1.10 In Section 3 a review of investment cost drivers such as security, fault levels, network losses etc are discussed in the context of short and long term economic efficiency.

1.11 Section 4 presents a critique of the principal approaches to pricing the use of electricity networks highlighting their strengths and shortcomings especially with regard to fulfilling the key network pricing objectives.

1.12 In Section 5 the methodology for determining distribution use of system charges based on the notion of the reference network is described in some detail explaining at the same time the way in which the methodology satisfies the primary objectives of network pricing set out in Section 2.

1.13 Section 6 discusses key considerations in the practical implementation of the methodology based on the reference network concept including transactional and transitional issues.

1.14 Section 7 presents key conclusions and recommendations for future work.

1.15 Section 8 is Acknowledgments and Section 9 is the Appendix.

2. Fundamental objectives of network pricing and issues for regulators, network operators and users

Objectives of network pricing

2.1 Network pricing should aim to achieve the following primary objectives:

- ***Economic efficiency (cost reflectivity)****:* in the context of electrical power distribution systems, economic efficiency is concerned with sending price signals to users of the network with respect to the costs the users impose on network operation and/or development. Efficient pricing distinguishes between different user locations and between different times of use thus avoiding cross subsidies.

  There are essentially two types of costs namely (a) *network operational costs* (b) *network development costs*. Network development costs involve investment into expansion of the network and its capacity. Network pricing based on network development costs is the primary focus of this report.

  In a competitive environment economic efficiency is achieved by sending cost reflective price signals to users of the network so as to influence their decisions with regard to (a) location in the network and (b) patterns of network use. This is the fundamental reason why economically efficient network use of system charges should be location and time-of-use specific. It is also worthy noting that because the focus of economic efficiency in pricing is to influence future behaviour, the investment costs that are relevant in the determination of efficient network use of system charges are the *future network expansion costs*[5] rather than present or past network costs.

  Methodologies for economically efficient allocation of losses in distribution systems with distributed generation have been proposed.

- ***Future investment signalling***: (a) send clear cost messages regarding the location of new generation facilities and loads (b) need for and location of new distribution network investments, i.e., encourage efficient network investment and discourage over-investment.

- ***Deliver on revenue requirements***: efficient prices based on network operating and/or development costs may not deliver the required revenue. These efficient prices would hence need to be *modified* to yield sufficient amount of revenue to allow efficient operation and development of distribution networks. This requirement may distort the objective of economic efficiency.

- ***Provide stable and predictable prices*****:** Price stability and predictability is important for users' investment decisions. The right balance must however be struck between price stability and flexibility allowing prices to respond to changing situations.

[5] The time horizon and assumptions on the locations of users, their future development and usage patterns would need to be defined for the future costs to be quantified.

- ***Determination of prices must be transparent, auditable and consistent***; allowing users and other interested parties to easily understand the structure and derivation of network tariffs.
- ***The prices must be practical to implement***: any proposed network pricing method should balance the economic efficiency of tariffs and their complexity as well as social objectives. Furthermore, from a practical standpoint the pricing method should be easy to understand and implement.

2.2 One of the major challenges in setting tariffs is establishing the trade off between various objectives of tariff setting. These include, as listed above, the ability to reflect accurately cost streams, efficiency in responding to changing demand and supply conditions, effectiveness in delivering appropriate revenue requirements, stability and predictability of revenue and tariffs which may be difficult to satisfy simultaneously.

Issues in network pricing

2.3 The issues involved in setting use of system charges from the perspective of the *regulator*, *network companies* and *users* of network services are summarised below.

<u>Issues from the Regulator's perspective</u>

2.4 Some of the key aims of regulation of distribution networks are to ensure that network charges are not excessive and that service quality is reasonable, while maintaining financial viability of distribution companies and their ability to invest in network operation and development. In order to achieve this, regulators often define the maximum allowable revenue that network companies can earn and set targets and incentive mechanisms for improving service quality[6].

2.5 On the other hand, the competitiveness and positioning of participants in the energy market is dependent upon the network pricing arrangements. As promotion of competition is also one of the primary objectives of regulation, network pricing should also be a regulatory concern. Whether or not participants in the energy market have open non-discriminatory access to networks is therefore in essence a network pricing problem.

2.6 One of the key issues in setting future DUoS tariffs will be to find an optimal balance between various objectives of tariff setting. Some of the specific issues that need to be recognised could include points such as:

- Choice of "optimal" time horizons for estimation of future demand and generation profiles that are necessary to evaluate future network costs and use of system charges.
- There is balance to be struck between stability of prices and cost reflectivity (ability to respond to changing demand and generation conditions). This balance influences the choice of the appropriate time horizon for price reviews.

[6] In relation to this, important objective of regulation is also to ensure efficient network operation and investment.

- Long-term versus short-term signalling - once a decision is made to focus on long-term signals in pricing, it may not be easy to simultaneously resolve short-term efficiency issues. The view is taken that in distribution systems long term investment signalling is more important than short term signalling.

2.7 Furthermore, when deciding on a particular network pricing regime, it will be important to establish the materiality of individual network cost drivers and assess the benefits of including these in network pricing. Moreover, it will be important to strike an appropriate trade off between the complexity of tariff evaluation and the granularity of the tariff structure, including the appropriate balance between tariff stability (and predictability) and cost reflectivity.

2.8 It will be also important to establish the principals of access arrangements for DG. Note that ER P2/5 is centered on network security from the perspective of *demand*, and it does not explicitly deal with the level of availability of the network to generators (given generators may opt for a less secure network access than demand for a reduced DUoS charge or reduced connection costs). It may appropriate to assess the need for the compatibility of distribution and transmission practices in this context.

2.9 It may be desirable to allocate network losses (and constraints through active network management) among network users, while recognising the impact of power factor.

2.10 It will be also important to undertake an assessment of the impact of alternative network pricing approaches on future network expenditure.

2.11 A number of the above points are matters of policy in the wider context and it may be important that these are considered in the overall context of distribution network regulation.

<u>Issues from network owner's perspective</u>

2.12 The distribution business is capital intensive, with irreversible investment with the long life assets of a small resale value. As a consequence, DNOs will be concerned with the long-term security of their investment.

2.13 Given that pricing will influence future locations of users, this will have an impact on the overall network expenditure, and it is important to understand this interaction when developing investment programmes.

2.14 Traditionally, distribution networks are operated as passive systems, i.e. real time network control problem resolved at planning stage. If a significant amount of DG is to be efficiently integrated in the distribution network, the philosophy of operation may need to change from passive to active.

<u>Issues from network user's perspective</u>

2.15 *Transparent and equitable use-of-system charges:* Participants in a competitive electricity market are sensitive to the costs they have to pay for network access as these costs affect their competitiveness. As suggested previously, pricing is the ultimate measure as to whether or not open non-discriminatory access exists. In economic terms non-discriminatory pricing means absence of cross subsidies and is achieved when prices reflect cost streams.

2.16 *Connection charges:* Connection charges have a major impact on the ability of new participants to enter the market. In order to facilitate increase in deployment rates of DG, connection policy in distribution networks is changing in favour of shallower connection for generators. This is consistent with the shallow connection approach practiced at the transmission level.

2.17 The modalities adopted for settling the connection charge are an issue of risk allocation between the network company and the DG. A policy where the connection charge is spread over several years is clearly beneficial to DG and lowers the barriers to entry.

2.18 *Stability and predictability of prices:* Stable and predictable prices enable planning activities within a business enterprise to be undertaken with a higher degree of certainty and are therefore always preferred by users of network services. Cost reflectivity will be one of the key criteria for evaluating the appropriateness of alternative pricing strategies. Given the expectations in the growth of various forms of distributed generation, it will be important to understand how charges for generators and demand customers may change. For example, if a generator connects in a demand dominated area and reduces the need for distribution network (counter flows), and if the pricing policy is cost reflective, the generator would be rewarded for operating in that particular part of the network. However, if in the future, more generators are connected to this area of the network and the aggregated output of generators becomes dominant factor for network design, the polarity of charges will change.

2.19 *Firmness of access and rules for management of network constraints:* Firmness of the network access is a matter of great interest to generators. In the future, the development of active network management and associated rules for management of network constraints may be important. Generators that opt to be constrained off during periods of reduced network availability may benefit from lower DUoS charges.

3. Role of distribution network cost drivers in pricing

3.1 As discussed in Section 2 the objective of distribution network pricing is to send signals to users of the network on the costs they impose on network operation and/or development. It follows from this that in order to calculate efficient network investment related prices it is necessary to first establish future network investment costs. Future network investments and the associated costs are the outcome of network planning. There is therefore a close link between network pricing and network planning. In other words network planning is a key step in network pricing. Network prices then reflect the impact that individual users have on the costs of the planned network.

3.2 Network planning is driven mainly by planning standards (security and safety standards) and incentive mechanisms within the regulatory framework that may drive investment (quality of supply, losses and incentives to connect DG). In the context of UK the main investment drivers in distribution network design are:

(i) Network security; the need to satisfy network security requirements by investing in adequate network capacity

(ii) System fault levels; requiring adequately rated switchgear and network components and

(iii) Network losses; need to strike an optimal balance between operating costs and network investment

(iv) Service quality expenditure required to improve network performance indicators e.g. CI and CMLs.

These are discussed below.

Security driven network expenditure

Network Planning Standards

3.3 Prior to privatisation, the Electricity Council was responsible for setting and maintaining a range of common technical and economic guidance documents, including Engineering Recommendation P2/5. ER P2/5 was intended to be used as a guide to system planning and design. The fundamental principle outlined within ER P2/5 is that there should be sufficient *capacity* in the system such that, in *predefined* outage situations, customers continue to receive a supply or have it restored within an acceptable time period. ER P2/5 defines the network design philosophy and, in the context of network pricing, the requirements to comply with the security standard are a key network cost driver[7].

[7] Historically, the structure of electricity distribution networks was driven by an overall design philosophy developed to support large-scale generation technologies. The level of security in distribution networks is defined in terms of the time taken to restore power supplies following a predefined set of outages. Consistent with this concept, security levels on distribution systems are graded according to the total amount of power that can be lost. In general, networks have been specified according to a principle that the greater the amount of power which can be lost, the shorter the recommended restoration time. This philosophy is formalised in the ER P2/5, and this standard is a part of the distribution network licence conditions.

3.4 ER P2/5 contains two tables. Table 1 states the minimum demand that must be met after certain specified circuit outages. This level is dependent on the Group Demand or Class of Supply. The amount of demand that can be supplied depends upon the available circuit capacities and critically, the contributions from local distributed generators. Table 2 in ER P2/5 specifies the contribution that can be attributed to generation connected to a particular load group.

3.5 Given that ER P2/5 was developed in 1970s, it does not currently recognise many of the modern forms of distributed generation currently being connected into distribution networks in the pursuit of Government climate change targets. Consequently, it is not possible to recognise the security contributions of many new forms of distributed generation. It is anticipated that ER P2/6 will supersede ER P2/5 in the near future. This will facilitate the inclusion of security contributions from distributed generation during network planning[8]. In other words, the ER P2/6 will specify the critical condition for network design in the presence of distributed generation.

3.6 The new ER P2/6 will provide a basis for *quantifying* the contribution that DG makes to system security i.e. the extent to which DG can reduce the demand for network facilities and substitute for network assets[9]. For various generation technologies, this is specified through a series of contribution factors that take into account the number of generators, their availability and operating regimes[10]. This is a pre-requisite for establishing cost reflective pricing in networks with DG that can recognise the positive impact that DG may have on network expenditure (reduction of network investment cost) and that can reward generators accordingly. On the other hand, in case that the operation of a generator is the prime driver for network design (reinforcement), the generator should expect to pay for the use of the assets involved.

3.7 As discussed, the ER P2/5 specifies the minimum capacity (composed of network and generation facilities) required to meet given group demand, during peak demand conditions. This is obviously relevant for demand-dominated areas.

3.8 On the other hand, ER P2/5 (or ER P2/6) does not deal explicitly with the question of minimum network capacity and security that may be appropriate to absorb generation outputs. There are two issues to consider: (i) level of security that connection provides to generation and (ii) level of security that the distribution system provides to generation.

3.9 Regarding (i), generators connected to the distribution network currently have a choice regarding how secure their connection should be. Generally, it seems that the generators tend to opt for less secure connection than loads. This could be explained by the fact that the cost of losing connection to the system for generation should be significantly less than for demand (the unit cost of not generating equals the electricity price at that point in time, while cost of energy not supplied to loads would be generally many times higher). However, it is

[8] R Allan, G Strbac, P Djapic, K Jarrett, "Methodology for developing ER P2/6", DTI report, April 2004

[9] In the network planning stage, generation contribution to network security, as specified by the standards, can be interpreted as firm generation output available at peak demand (during specified period of time for intermittent generation).

[10] For example, a CHP generator (spark ignition) with an availability of 60% can contribute to network security with 40% of its installed capacity.

important to remember that the contribution that generators make to network security will be influenced by the security of their connection.

3.10 Regarding (ii) generators are likely to be satisfied by the level of security that distribution system provides through network security standards. For example, if a particular substation has two transformers (but only one is needed to carry out full load), downstream generators are unlikely to require, say, three transformers to further secure their output (as the cost of not generating is significantly lower that the cost of not supplying demand).

3.11 Generators however may wish to accept lower levels of security than that provided to demand. In an *actively* managed network, generators could find it attractive to curtail their outputs during periods of reduced availability of the network (planned or unplanned outages of upstream circuits), for a reduced DUoS charge. In the context of the above example, in case that one of two transformers in the substation is out of service, and that the remaining transformer cannot carry full output of generation, downstream generators may find it profitable to curtail their output rather than to incur the cost of the substation reinforcement (via increased DUoS)[11] .

3.12 The adequacy of the network is usually examined so that the network under all loading conditions can (normally) absorb full output of distributed generation. Hence, in generation-dominated areas, the critical condition will be determined by the coincidence of maximum generation output and minimum load. If the system imposes no operational constraints under these conditions, all other conditions will be less onerous. On the other hand, under active network management, generators may decide to curtail their output in order not to drive investment. Both of these cases can be accommodated in the proposed pricing regime.

3.13 This means that, under passive operation philosophy, two conditions will need to be examined when determining the adequacy of the network:

(iii) Maximum load and secure generation output
(iv) Minimum load and maximum generation conditions

3.14 Clearly, only one of these conditions will be relevant for designing a distribution circuit. This exercise is performed in the proposed pricing methodology and the critical conditions for determining maximum flow for each individual plant item determined. This is the key for determining the polarity of charges.

3.15 The time of use feature in the network pricing is important as it tracks the network use pattern by the users of the network to ensure their behaviour is consistent with their declared network use patterns at the time of network planning. This may require appropriate metering of demand and generation (half-hourly energy or seasonal maximum demand or generation metering).

Voltage considerations

3.16 DNOs have an obligation to supply their customers at a voltage that is within specified limits. In this context, evaluation of voltage profiles under critical

[11] Note that (in the longer term) it may not be desirable to allow generators to disconnect form the network in times of reduced network availability and hence the generators may be denied the option of an insecure connection (as is the case at the transmission level). This may be a question for grid codes and may be considered in the wider context of security of supply.

loading conditions is a part of network design. However, sometime voltage drop (rise) can be a sole driver for network design (reinforcement) and hence is separately discussed in this section.

3.17 In order to keep the voltage fluctuations within permissible limits, voltage control in distribution networks is carried out automatically by On-Load Tap Changing transformers and occasionally by reactive compensation installed at critical locations. For example, it is well known that the ratio of the MV/LV transformer is usually adjusted so that at times of maximum load the most remote customer receives acceptable voltage, just above the minimum value. On the other hand, during minimum load conditions the voltage received by all customers is just below the maximum allowed. The robust specification of passive networks effectively minimises voltage variations across a wide range of operating conditions, e.g. from no load to full load.

3.18 Voltage considerations may drive design (capacity) of long distribution feeders, particularly in low and medium voltage networks. This is because the ratio of resistance over reactance of these circuits is usually significant and hence the transport of active power in these networks makes significant impact on voltage drop. This is in stark contrast to high voltage distribution and transmission circuits where reactive power flows determine network voltage profile.

3.19 Therefore, when designing low and medium voltage circuits, in order to keep the voltage drop within limits, it may be necessary to select conductors of increased capacity, i.e. capacity that is greater than the necessary minimum dictated by thermal loading. In this case, voltage drop rather than thermal loading would be the investment driver. It is however important to note that the maximum voltage drop will occur during maximum loading of the circuit. Hence, implicitly, maximum loading can be considered as the investment driver, given the voltage drop constraints. In the context of network pricing, we can treat loading as the primary cost driver of such circuits (bearing in mind that the actual capacity selected will need to be greater than the maximum flow to keep the voltage drop within allowable limits).

3.20 In this context, if a generator is connected to a demand dominated area, with output that offsets the power flow in upstream circuits improving the voltage profile, this generator clearly reduces the demand for distribution network capacity, and will postpone network reinforcement. This is clearly very similar to a generator security contribution and the extent to which the generator offsets the power flow in upstream circuits (and hence improves the voltage profile) will be specified in ER P2/6. This contribution will need to be recognised in a cost reflective pricing.

Fault level driven network expenditure

3.21 In addition to transformers and lines (overhead or cable), circuit breakers and other switching equipment can be classified as major items of distribution plant. The rating of the fault breaking facilities is not however determined explicitly by the power flows but by the maximum fault currents that the device needs to clear (so called make and break duties of circuit breakers). Given the design of the system, these fault currents can be very significantly greater than the current under normal operating conditions.

3.22 In the context of cost reflective pricing it would be possible to separate the network prices driven by loading, from the prices driven by fault breaking facilities.

3.23 Most DG plant uses rotating machines and these, when connected directly to the network, will contribute to the network fault levels. Both induction and synchronous generators will increase the fault level of the distribution system. In urban areas where the existing fault levels approach the ratings of the switchgear, the increase in fault level can be a serious impediment to the development of DG, as uprating of distribution network switchgear can be very expensive.

3.24 A fault level analysis can be carried out to determine the contribution of each of the generators to fault levels at various busbars. This could be used to allocate the cost of fault breaking facilities to network users[12]. This can include generators connected to the distribution network but also suppliers that enter the distribution network at the corresponding Grid Supply Point (as the majority of the fault current would usually be attributed to the large conventional plant connected to the transmission network). This is illustrated in Figure 3-1 below.

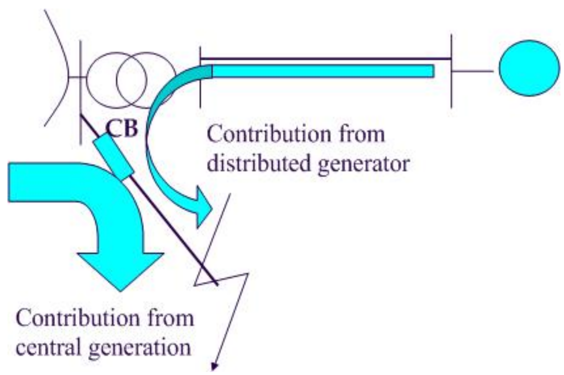

Figure 3-1 Contribution of central and distributed generators to fault level

3.25 As indicated, in principle, it is possible to decouple the allocation of cost of primary plant driven by loading, from allocation of costs of equipment driven by fault contribution. However, it should be remembered that the cost of circuit breakers may not be very significant part of the total substation cost. However, this option can be kept open and could be included in the overall DUoS model, if desired.

Losses driven network design expenditure

3.26 The impact of losses on the design of distribution cable and overhead networks can be quite profound. Work carried at the University of Manchester showed that adopting a minimum life-cycle cost methodology, which balances the capital investment against the cost of the system losses over the expected life of the circuit, as a basis for circuit design can lead to very different capacities to those that would result from the procedure described above.

3.27 In this methodology the optimal network capacity for pure transport of electricity is determined through an optimisation process where annuitised

[12] Fault level analysis is a routinely carried out during network design and can be easily implemented in the pricing exercise.

network capital costs and annual network operating costs (of which network variable losses are the most significant component) are traded off. This optimisation requires a calculation of the annual network cost of losses and involves modelling of annual variations of load and generation as well as associated electricity prices including the mutual correlation between these quantities. The network costs of losses are then balanced against annuitised network capital costs to determine the optimal capacity required for economical transport of electricity.

3.28 Preliminary results[13] given in the form of the optimal circuit utilisation (ratio of maximum flow through the circuit and optimal circuit capacity), for different voltage levels, are presented in Table 3-1.

Table 3-1 Optimal utilisation factors of cables and overhead lines in a typical distribution network

Voltage level	Type of conductor	
	Cable	Overhead line
11kV	0.2 - 0.35	0.13 - 0.2
33kV	0.3 - 0.5	0.17 - 0.25
132kV	0.75 - 1	0.3 - 0.5

3.29 These results indicate that the optimal utilisation of distribution circuits, particularly at lower voltage levels, should be quite low. Secondly, the optimal design of circuits taking the cost of losses into account satisfies the vast majority of security requirements at no additional cost, in cable networks up to 33kV and overhead lines throughout distribution systems. Further analysis indicates that this result is a combination of two effects. The first effect is the relatively large cost of losses due to the coincidence of high electricity price with high demand. The second effect is the relative fall in the price of cables and overhead lines due to maturity of the technology and increase in competition in the manufacture of this equipment.

3.30 As losses may drive investment in lines (11 kV and 0.4 kV in particular), then charging for use of the network on the basis of peak demand as at present may not be appropriate as losses are present at all times. Furthermore, availability of DG and its contribution to network security may not be important for determining the component of DUoS charges associated with 11 kV and 0.4 kV assets.

3.31 In this optimisation, the capacity determined for pure transport applies to cables and overhead lines only. Ratings of other items of plant such as transformers and circuit breakers are determined on the basis of other considerations.

3.32 Determination of DUoS charges in cases where the capacity of the assets are driven by losses is elaborated in our previous work[14]. It should be stressed this process concerned is with allocation of *investment costs* and is different from loss allocation which is concerned with allocating losses.

[13] Curcic, S., G. Strbac, and X.-P. Zhang, *Effect of losses in design of distribution circuits.* Generation, Transmission and Distribution, IEE Proceedings, 2001. 148(4): p. 343-349.

[14] Mutale, J., G Strbac. A Framework for Development of Tariffs for Distribution Systems with Embedded Generation. in CIRED'99. 1999. NICE, France

Reliability driven network design and expenditure

3.33 Since privatisation, a number of operational standards have been developed by successive regulatory authorities, which safeguard supply quality. These operational standards include the Guaranteed Standards and Overall Standards of Performance. Guaranteed Standards set service levels that must be met in individual cases. If the DNO fails to provide the level of service specified, it must make a penalty payment to the customer affected upon request.

3.34 At present, the main security related Guaranteed Standard (GS) focuses upon supply restoration times. To ensure that inconvenience to customers is kept to a minimum, this GS requires DNOs to restore supplies within 18 hours of becoming aware of a fault on their system. Additional performance measures have been developed as part of the Information and Incentives Project (IIP).

3.35 Overall Standards (OS) address other aspects of service quality where it is not appropriate to give individual guarantees, but where customers have a right to expect predetermined minimum levels of service from DNOs. No penalty payments are made if these levels are not achieved and it has been proposed that OS should be removed or replaced.

3.36 There has been a shift of focus in the regulation of distribution networks, from asset based to performance-oriented regulation. The Information and Incentive Project (IIP) was established to strengthen incentives and increase the quality of outputs. As the IIP is based on financial penalties and rewards, the overall distribution revenue is a function not only of the operating and capital costs incurred by the network owner in providing the service (driven by security standards), but also depends on the quality of service actually delivered to the customer[15]. The indices used to measure supply quality are the number of interruptions per 100 connected customers per year (CIs), the number of customer minutes lost per connected customer per year (CMLs) and Worst Served Customers (WSC).

3.37 The network design practices, as specified in ER P2/5 have effectively determined the reliability profile experienced by end customers. The performance of medium and low voltage networks has a dominant effect on the overall quality of service[16]. The vast majority of CIs (85%) and CMLs (93%) have their cause in LV and MV networks.

3.38 Quality of supply has been a significant driver of network capital and operating expenditure, particularly in MV and LV networks. Typical measures for service quality improvements would include feeder automation (that support more rapid fault isolation and supply restoration processes) under-grounding of overhead circuits or replacing light with heavy constructions overhead lines (that reduce number of faults), increase in mobility of fault deployment teams, management of spare parts etc.

[15] It is important to note that ER P2/5 do not address the question of frequency of outage, and it deals only with restoration times (expected, rather than actual values).

[16] As planning standards do not require redundancy of assets on low voltage (LV) networks, the duration of outages caused by LV faults is determined by component repair and replacement times. Medium Voltage (MV) networks are generally configured such that interruptions caused by single faults can be restored much more quickly, e.g. through switching.

3.39 Statistics also show very significant differences between the quality of services received by urban and rural customers. Service quality differentiated pricing, as a value based approach, is not considered appropriate and hence is not discussed further in this report.

3.40 In principle, DG can substitute some of these measures, although in practice this may be challenging. For DG to improve service quality on these networks, the generation must be connected at 11kV or 0.4kV, i.e. “below” the point of fault. For example, supply interruptions caused by faults in 0.4 kV networks cannot be readily impacted by generation connected at or above 11kV. The requirement for DG to be connected at relatively low voltage levels in order to impact upon service quality could restrict such opportunities to relatively small sized generation. Furthermore, it should be possible to operate networks with DG in islanding mode, although this is currently technically and economically challenging[17].

3.41 Given that DG is unlikely to materially impact DNOs service quality driven capital and operating expenditure in the short to medium term, it is proposed not explicitly deal with the allocation of such resources at this point.

Impact of active management

3.42 As indicated above, distribution network control problem has been traditionally resolved at the planning stage (passive operation) and hence the network provides an almost firm access to demand customers.

3.43 Under the passive network operation, generators would be offered a similar level of access to the system as demand. In the future, however, the development of active network management and associated rules for management of network constraints may become important. Generators that opt to be constrained off during periods of reduced network availability may benefit from lower DUoS charges. Hence active distribution management may be linked with DUoS arrangements.

3.44 Historic network design philosophy is known to considerably limit the amount of distributed generation that can be connected to existing network. Limiting factors are (i) voltage rise effect in rural networks (11 kV primarily), (ii) increased fault levels in urban areas and (iii) thermal constraints in both rural and urban systems. For this reason, increasingly active network management techniques are under evaluation.

3.45 There has been considerable work undertaken with respect to the integration of DG within distribution networks, to investigate the benefits of active management with a view to maximising the generation capacity which can be accommodated. Benefits are in the form of avoided reinforcement costs of primary plant which are partially offset by the cost of active management Such costs are associated with increased expenditure on secondary infrastructure, control and communication facilities, and increased complexity of system management. Given that active management tends to increase the utilisation of the existing distribution network, it may result in increased losses.

[17] ILEX/G Strbac, J Mutale, “Ancillary Services Provision from Distributed Generation”, Report to DTI/FES, September 2004.

Control of voltage and flows

3.46 If a significantly sized distributed generator is connected to a relatively long 11kV circuit, then the flows in the circuit will change and hence the voltage profiles. The most onerous scenario is likely to be when the customer load on the network is at a minimum causing the output of the distributed generator to flow back through the network to the source. This will cause a voltage rise effect.

3.47 The present philosophy of operating distribution networks with distributed generation (voltage control in this particular case) is based on passive network management. The key advantage of this approach is in the simplicity of network operation, as the real time control problem is being resolved at a planning stage. However, this passive operation of distribution network limits the capacity of generation connected based on the extreme condition of minimum load, maximum generation. In order to minimise the overall effect of distributed generation network operators prefer to connect distributed generation at higher voltages where their impact onto voltage levels is minimal. However, the commercial viability of distributed generation projects is sensitive to connection costs. These costs increase considerably with the voltage level at which the distributed generation is connected; generally the higher the voltage or sparser the network, the higher the cost. The developers of distributed generation therefore prefer to connect at lower voltages. This conflict of objectives between distributed generation developers and network operators is usually settled through simple deterministic load flow studies, usually based on one critical case representing conditions of minimum load and maximum distributed generation output.

3.48 Various degrees of integration based on active management are available, ranging from a simple local based control of generation to a coordinated control between distribution and generation facilities over interconnected distribution circuits[18]. This co-ordinated, system level voltage and flow control could be based on a controller that allows this integrated operation to be implemented.

3.49 In some circumstances, active management may require DG to be constrained off occasionally[19]. In other words, application of active management may reduce the level of network access available to some generators. As a part of the evaluation of alternative active management schemes, balance between costs of constraints and costs of reinforcement should be assessed, and on the basis of such studies the decision for a particular solution is derived. In such cases, there will be information available regarding the expected duration of period during which generation may be constrained off. This could form a basis for a bilateral agreement between the DNO and the generator regarding the level of access that is likely to be achievable, depending on the particular solution adopted.

3.50 Of course, the benefit for the generator of occasionally being constrained off may be in the form of reduced connection and DUoS charges. This effect can be captured by the proposed pricing methodology.

[18] G Strbac, N Jenkins, P Djapic, M Hurd, G Nicholson, Benefits of active management, DTI 2003.

[19] Similarly to voltage rise effect being managed by constraining off generation, in order to prevent power flows exceeding occasionally the thermal capacity of the circuit and it may be economically efficient to constrain off generation.

Fault level management

3.51 As discussed above, in urban areas, where the existing fault levels approach the ratings of the switchgear, the increase in fault level caused by DG may require a very expensive up rating of distribution network switchgear.

3.52 The technical solutions, other than replacing switchgear are limited[20]. The fault level contribution of a DG may be reduced by increasing the network impedance e.g. transformer or a reactor can be inserted in the circuit, but at the expense of increased losses and wider voltage variations on the generator. Similarly, fault levels can be reduced by reconfiguring the network (network splitting), with the consequence of increased voltage fluctuations, losses and risks of interruptions, which all come with an associated cost. Generally, the costs of actively managing the fault level are expected to be lower than the cost of replacing the switchgear.

3.53 In some countries explosive fuse type fault current limiters are used to limit the fault level contribution of DG plant. Furthermore, superconducting fault current limiters may become available in the future, potentially reducing network development costs.

3.54 Similar to voltage and thermal constraint management, the benefit of this foem of active management will be in reduced connection and/or DUoS charge. This effect can be incorporated by the proposed pricing methodology.

Inclusion of cost drivers in pricing

3.55 All the network future costs driven by the considerations discussed above should be included in the determination of network prices. While it is true that in the ideal case all investment drivers must be included in the determination of network prices, in practice the choice of which investment drivers should be included in the process would be based on the materiality of the individual cost driver. In other words network planning is key input to network pricing. However, nnetwork design for network pricing is different from (detailed) technical network design. Unlike technical network design, network design for pricing need not consider detailed network design and planning processes, but must consider the commercial impact of the network design and planning drivers.

3.56 In order to demonstrate the basic principles of the network pricing methodology proposed in this report network planning has been assumed to be driven by the network security standards. Hence the future costs are also driven by network security considerations. However the proposed pricing framework would also allow other cost drivers to be included as appropriate while balancing complexity against materiality.

3.57 It should be noted that in practice, due to constraints imposed by practical considerations (e.g. billing systems), the granularity of DUoS tariffs will be limited. Hence, it may not be appropriate to include the complete set of cost drivers in their full complexity, obtain a complex set of tariffs as a result (every single location having a different tariff with a complex time of use structure),

[20] For DG connected through power electronic interfaces, fault contributions can be more easily controlled.

and then carry out a process of drastically simplifying the tariffs to obtain a very small number of different tariffs. Instead, given the restrictions on the granularity of the tariffs, it may be more appropriate to be selective in the process of choosing the set of cost drivers that have the most material impact on the future network cost and by doing so optimise the complexity of tariff production.

3.58 Economically efficient network prices are computed on the basis of marginal cost pricing principles. In marginal cost pricing the future network costs are allocated by considering the marginal impact of each user on network costs. The type of user and their patterns of network use as well as network reliability requirements are key determinants of the impact of individual users on the network costs.

Distribution network losses

3.59 The percentage of annual energy losses in the urban and rural network varies from about between 4.5 to about 9% respectively. According to Ofgem[21], the total losses in UK (rural and urban) distribution networks are around 7%.

3.60 It should be noted that more than 50% of the total losses are incurred in low voltage networks and 11/0.4 kV transformers. In this context, it may be important to recognise the impact that domestic CHP may have on network losses.

3.61 In general, the presence of DG changes the power flow patterns and therefore the losses incurred in transporting electricity through distribution networks. With relatively small levels of penetration, DG would normally, but not necessarily, contribute to power loss reduction as the generation energy flow is generally against the major net flow. On the other hand, higher levels of penetration may be accompanied with increases in network losses. Furthermore, one of the implications of active destruction management is increase in network losses[22].

3.62 In the context of the review of the network pricing regimes, it may be appropriate to examine the cost and benefits of introducing a cost reflective loss allocation scheme.

3.63 Another relevant issue in relation to network losses is power factor of loads, and it can have a significant impact on the magnitude of losses, particularly in rural networks. However, there is little information about the ranges of power factors across the UK distribution networks. Again, given the review of the network charging mechanism it may be appropriate to examine the importance and the materiality of incorporating power factor in the loss allocation schemes.

3.64 Methods for allocating losses among network users (including DG), taking into account the power factor, are discussed in the next section.

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[21] http://www.ofgem.gov.uk/ofgem/microsites/microtemplate1.jsp?toplevel=/microsites/distribution&assortment=/microsites/distribution/distlosses

[22] G Strbac, N Jenkins, P Djapic, M Hurd, G Nicholson, Benefits of active management, DTI 2003

4. Review of network pricing approaches

4.1 The main approaches used to price network services that are in common use around the world can be classified broadly into two categories.

- Methods based on operational costs, e.g. Short Run Marginal Cost (SRMC)
- Methods based on network investment costs

These methods are reviewed below.

SRMC driven network pricing

4.2 SRMC prices are location specific energy prices that reflect the generation operating cost (marginal fuel costs) taking into account network constraints and losses. These prices vary in time (quarter hourly, half hourly or hourly as the case may be) and are known to allocate optimally scarce network resources in the short term, while maximising efficiency of generation operating system in the presence of network constraints. This pricing approach is applied in the US and there is extensive debate about the merits of this approach at the transmission level[23]. Given the context of the UK electricity market environment the SRMC pricing approach is not considered further in this report.

Pricing driven by network investment

Distribution Reinforcement Model (DRM)

4.3 For the evaluation of charges for the use of distribution networks, the majority of DNOs use a model known as the Distribution Reinforcement Model (DRM). This model is employed to evaluate the long run marginal cost of expanding, maintaining and operating the distribution system. This is achieved by calculating the network cost of adding a 500 MW load at each voltage level on the system maximum demand.

4.4 These costs are then allocated across voltage levels and customer groups such that the resulting DUoS charges are somewhat cost reflective. This is achieved by identifying the contribution of each customer group to the long-term distribution system cost.

4.5 The resulting tariff takes the form of maximum demand and/or unit related charges. Maximum demand charges are used for levels of the system close to customers. This is based on the argument that customers will maximise asset utilisation with respect to capacity of the local network to which they are connected. These charges are usually expressed in terms of £/kVA/month. On the other hand, unit based charges in £/kWh reflect the impact on the network cost further up the system. This approach is supported by the argument that the customer individual maximum demand is less likely to coincide with the system maximum demand.

4.6 Although the tariffs are design to be cost reflective a number of simplifying compromises are made in the implementation phase. For example, urban and rural customers pay the same charges, although costs of supplying rural

[23] e.g. W Hogan website - http: //ksghome.harvard.edu/~whogan/

customers are generally higher than those of urban. This cross-subsidy is considered socially desirable.

4.7 It is important to bear in mind that distribution use-of-system tariffs have been developed for customers who take power from the network rather than for customers who inject power into the network. In the context of the objective to facilitate the developments in distributed generation it becomes important to develop a pricing regime that will recognise the impact that distributed generation makes on network costs. One of the key issues is the economic efficiency of tariffs and their ability to reflect cost streams imposed by the users, particularly distributed generation.

4.8 The impact of distributed generation on distribution networks (in terms of costs and benefits) is site specific, it may vary in time, will depend on the availability of the primary sources (important for some forms of renewable generation), size and operational regime of the plant, proximity of the load, layout and electrical characteristics of the local network, etc. It is not, therefore, surprising that the relatively simplistic DRM tariff structure, with network charges being averaged across customer groups and various parts of the network, cannot reflect the cost impact of distributed generation on distribution network.

4.9 It should be noted that DRM tariffs have no real ability to capture the impact of multi-directional flows (caused by the presence of distributed generation) and cannot deal with the temporal and spatial variations of cost streams. The developed model should therefore be able take into account changes in directions of power flows driven by distributed generation[24].

Investment cost related network pricing

4.10 Investment Cost Related Network Pricing (ICRP) was developed by National Grid Transco (NGT). In this pricing approach, the optimal capacity of the network is determined from a transmission network model in which predetermined generation output corresponding to the maximum demand is assumed. The maximum demand is the planned peak demand, which is met by generators in proportion to their installed capacity (e.g. 83% in the case of 20% generation margin). This method takes into account security in an approximate way through a security factor. The prices are calculated on the basis of the impact of incremental utilisation on planned critical flows in various circuits. This impact is in effect the sensitivity of planned critical flows to network injections. The sensitivity factors are combined with the circuit prices[25] to compute nodal transmission use of system prices. These prices, which are location specific, are then grouped into various zones for generation and demand. Finally the prices are adjusted to raise the allowed network revenue in such a way that generators face positive and negative charges depending on their locations while demand charges are always positive. Price differentials between zones are maintained.

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[24] A summary overview of costing and pricing of distribution networks together with a description of the DRM are presented in "Costing and Pricing of Electricity Distribution Services" (by P Williams and G Strbac), *IEE Power Engineering Journal* Vol. 15, No 3, June 2001 (125- 136). Furthermore, a discussion on various connection and DUoS charging options including a description of the concept of entry-exit charging methodology are presented in "Distribution Network Connection: Charging Principles & Options" (by ILEX), report to ETSU K/EL/00283/00/00.

[25] Note that substation costs are excluded from the calculation of nodal prices using sensitivity factors

Pricing based on the concept of reference network

4.11 The concept of a reference network is a construct derived from economic theory and has a long history[26,27,28] although the term "reference network" (or "economically adapted network") was not necessarily used explicitly by all of these authors. Nevertheless, the fundamentals of the idea of applying the "global economic optimality" of the network for pricing purposes have been implicitly discussed. In particular, Farmer pioneered the application of this concept for pricing transmission in a competitive environment. The application of the concept of reference networks to regulation of distribution networks is discussed[29]. This approach was also used to examine the relationship between short-term locational marginal prices (associated with corresponding financial or physical transmission rights) and transmission investment[30]. The application of a reference network as a framework for regulating transmission monopolies, together with an efficient implementation methodology has also been investigated[31].

4.12 Although the level of detail and hence the complexity involved in determining the "global economic optimality" of a transmission and distribution networks may vary considerably, the reference network, in its simplest form, would be topologically identical to the existing network, with the same generation and load layouts, would operate at the same voltage levels as the real one, but the individual transmission and distribution circuits would have optimal capacities. These optimal capacities are determined in an exercise that balances operating cost and investment cost of networks, while satisfying security constraints. Clearly, fewer and smaller duration constraints result from higher circuit capacities. This implies higher network investment costs but lower operating costs of the system. If we now assume that the network capacity can take any size (with, say, constant marginal investment cost), the resulting reference network would have exactly the optimal amount of constraints to which the optimal amount of investment cost would be associated, such that the total investment and operating costs are minimised.

4.13 This is very similar to the NGT methodology except that in the NGT method the generation outputs do not follow generation costs but are uniformly scaled to meet a single peak demand which is consistent with NGT network planning standard. If critical planned flows obtained from NGT pricing were used to design the network the corresponding circuit capacities would be equal to the least cost network, which is in essence the reference network.

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[26] Boiteux, M. (1949) La tarification des demandes en pointe: applicationde la theorir de la vente au cout marginal, *Revue General de Electricite*, Vol. 58**,** No. , 321-340

[27] Nelson, J. R. (1967) *Marginal Cost Pricing in Practice,* Prentice-Hal

[28] Farmer, E. D., Cory, B. J. and Perera, B. L. P. P. (1995) Optimal Pricing of Transmission and Distribution Services in Electricity Supply, *IEE Proc.,* Vol. 142**,** No. 1.

[29] Strbac, G., Allan, R.N., (2001) Application of reference network to regulation of distribution networks, Power Engineering Journal, Vol. 15, No 6.

[30] Juan Araneda, "Foundations of Pricing and Investment in Electricity Transmission", MPhil Thesis, UMIST, 2002

[31] Mutale, J., "Framework for allocation for transmission and Distribution network costs", Ph.D thesis, UMIST, December 1999

4.14 The proposed methodology for distribution pricing is also based on the reference network concept. The key difference is that the critical flows which determine minimum circuit capacity[32] are determined not from a single load flow but require evaluation of two or more network loading conditions. This is consistent with the newly proposed distribution security standard (ER P2/6) that quantifies the contribution that DG can make to network security.

4.15 In distribution systems optimal capacities should be derived on the basis of assumed investment drivers. The subject of investment drivers was discussed in Section 3. An illustration of the fundamental principles of network pricing based on the reference network is presented in the following section. A more detailed discussion of the methodology is presented Section 5.

Illustration of basic principles of proposed network pricing

4.16 The basic concept of allocating future network costs using marginal cost pricing is illustrated with the aid of two simple examples based on two-bus systems (see Figure 4.1 and Figure 4.3). Example 1 has a small wind farm located at node 2 whereas in example 2 a large wind farm is located at node 2. The two systems have identical demand levels and profiles for winter and summer periods. The demand profiles are shown in Figure 4.2 while the demand levels are shown in Figure 4.1 and Figure 4.3.

4.17 The forward looking annuitised investment cost for the circuit between node 1 and node 2 (for the two networks) is assumed, for illustrative purposes only, to be equal to £7/kW/year (this is assumed to represent costs of the two lines in the circuit).

<u>Example 1: Two bus system with small wind farm</u>

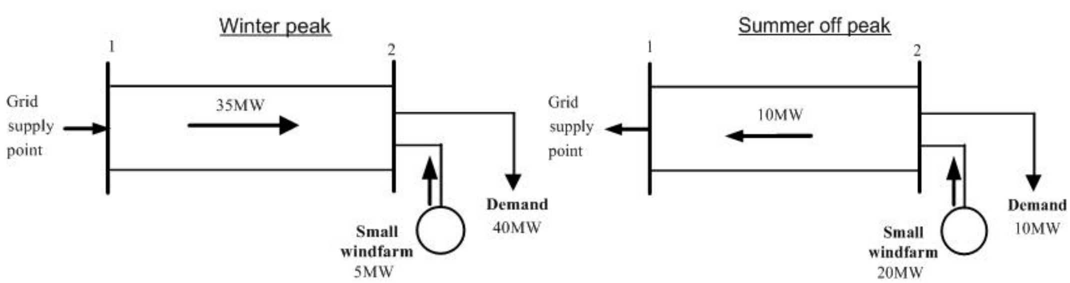

Figure 4-1 Example 1: Two-bus power system flows

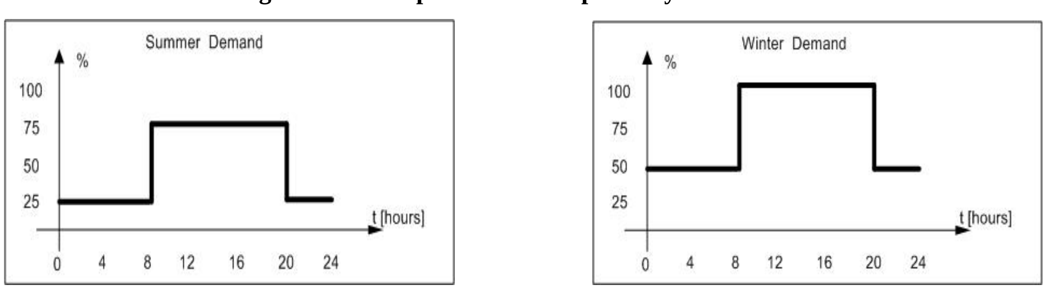

Figure 4-2 Demand profiles for examples 1 and 2

[32] This minimum capacity is also called the reference capacity

4.18 The peak and off-peak demand levels shown in Table 4.1 have been computed based on the profiles in Figure 4.2. Taking the assumed wind farm output during peak and off peak periods in Figure 4.1 and the computed demand levels, the circuit flows in Table 4.1 for peak and off peak periods have been computed.

Table 4-1 Generation and demand profiles for Example 1 two-bus system

	Winter		Summer		Critical flow	Classification of asset
	Peak	Off-peak	Peak	Off-peak		
Demand (MW) - A	40	20	30	10	-	-
Generation (MW) - B	5	20	5	20	-	-
Line flow (MW) - C = B-A	35	0	25	-10	35	DD

4.19 The critical flow is found as the highest of the flows in summer and winter periods. To aid understanding of the cost reflective allocation of costs to investment drivers all assets are classified as either demand dominated (DD), generator dominated (GD). For a radial system, by definition the *critical flow for a DD asset is away from Grid supply point* towards the load. In contrast the direction of *critical flow for a GD asset is towards the grid supply point* (counter flow). In Figure 4-1 the direction of the critical flow is determined by the demand and hence the circuit is characterised as DD.

Critical loading conditions

4.20 Note that in this example there are two critical loading conditions considered in determining critical flows and hence classifying assets into DD or GD. These are:

- Maximum demand and secure generation output (winter peak) ➔generation output is taken to be equal to the generation contribution to network security as prescribed in the security standard (ER P2/6).
- Minimum demand and maximum generation (summer off-peak) ➔ generation output equal to capacity of generator

Computing DUoS prices

4.21 Future network costs are allocated on the basis of marginal cost pricing principles. In accordance with the marginal costing the use of the circuit between node 1 and node 2 is charged only during the period of maximum loading of the circuit. If an additional unit of power is imposed on the circuit during its maximum loading, this will require reinforcement of the circuit capacity. When the plant is loaded below its maximum capacity, an additional unit of power will not require reinforcement, and hence the plant capacity charge is zero. In the case system shown in Figure 4.1 increasing demand at node 2 by 1MW during time of critical loading of the circuit will require reinforcement of the circuit, hence demand should be charged for the use of this asset. On the other hand increasing generation output during the critical loading condition (winter peak) will reduce the critical flow for 1MW and increase the available capacity by 1MW, thus benefiting the system. Generation should therefore be rewarded for conferring this benefit to the system.

4.22 Demand and generation prices are in theory equal in magnitude and polarity[33]. The resultant payments however have opposite polarities because incremental changes in generation and demand on line flow have opposite effects. A summary of the overall payments for the two-bus system in Figure 4.1 is given in Table 4.2.

Table 4-2 Nodal, time-of-use network price and user payments for Example 1

		Winter peak	Winter off-peak	Summer peak	Summer off-peak	Total
Nodal DUoS at node 2 (£/kW)	- A	7	0	0	0	
Demand level (MW)	- B	40	20	30	10	
Generator output (MW)	- C	5	20	5	20	
Demand payment (£'000)	- D=AxB	280	0	0	0	280
Generator payments (£'000)	- E=AxC	-35	0	0	0	-35
Net payments (£'000)	- F=D+E	245	0	0	0	245

4.23 Note that the optimal network prices (DUoS charges) recover the cost of the reference network (35,000 kW x 7£/kW/yr = 245,000£/yr). It can be proved that, in general, efficient network prices (based on the reference network concept) will always recover *exactly* the cost of the reference network. Hence, the cost reflective (efficient) network prices *allocate* the cost of the reference network. Given that in practice allowable revenue will be different to the cost of reference network, revenue reconciliation will need to be carried out.

Example 2: Two bus system with large wind farm

4.24 The same computations to find the critical flow, nodal prices and user payments carried out in Example 1 are repeated in this example (Figure 4.3), which has a larger wind farm.

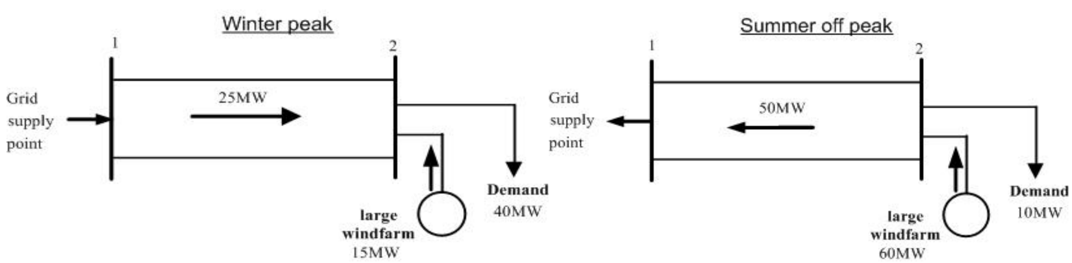

Figure 4-3 Example 2: Two-bus power system flows

4.25 Following the same process as in example 1 the flows for example 2 shown in Table 4.2 have been computed. Unlike in example 1 where the critical flow is determined by demand, the critical flow in this case is determined by generation. Hence the circuit is classified as GD.

[33] Starting from the theoretical prices, these can be subsequently modified to obtain different load and generation price profiles while meeting desired revenue recovery constraints.

Table 4-3 Generation and demand profiles for Example 2 two bus system

	Winter		Summer		Critical flow	Classification of asset
	Peak	Off-peak	Peak	Off-peak		
Demand (MW) - A	40	20	30	10	-	-
Generation (MW) - B	15	60	15	60	-	-
Line flow (MW) - C = B-A	25	-40	15	-50	50	GD

4.26 The computed nodal, time of use DUoS prices and associated user payments are shown in Table 4.4. Note that the reference network prices recover exactly the cost of the reference network (50,000 kW x 7£/kW/yr = 350,000£/yr).

Table 4-4 Nodal, time-of-use network price and annual user payments for Example 2

		Winter peak	Winter off-peak	Summer peak	Summer off-peak	Total
Nodal DUoS at node 2 (£/kW)	- A	0	0	0	-7	
Demand level (MW)	- B	40	20	30	10	
Generator output (MW)	- C	15	60	15	60	
Demand payment (£'000)	- D=AxB	0	0	0	-70	-70
Generator payments (£'000)	- E=AxC	0	0	0	420	420
Net payments (£'000)	- F=D+E	0	0	0	350	350

Observations from the two examples

4.27 Table 4.5 presents a summary of the final results from examples 1 and 2.

Table 4-5 Nodal network nodal, time use use-of-system charges and annual user payments

	Winter peak Nodal price (£/kW) Node 2	Summer off-peak Nodal price (£/kW) Node 2	Generator payment (Price x Generation in period) (£'000)	Demand payment (Price x Demand in period) (£'000)	Annual Net payment (Goes to pay for the asset) (£'000)
Example 1	7	0	-35	280	245
Example 2	0	-7	420	-70	350

NB: By chosen nomenclature Generator injection is negative and conversely Demand injection is positive

4.28 It is clear from Table 4.5 that the use of system charge is location and time-of-use specific:

- In example 1, which is demand dominated, the direction and the magnitude of the critical flow is determined by maximum demand condition. The nodal use of system charge is positive and demand pays for using the circuit. Demand charge applies in winter peak period and is related to the peak demand. The generator gets paid according to its contribution to security (P2/6) (during maximum demand period). In all other periods DUoS charges are zero.
- In example 2, the opposite situation applies. The system is generation dominated and the direction and magnitude of the critical flow is determined by maximum generation output and minimum demand. The nodal use of system charge is negative because the circuit is generator dominated and

hence the generator pays for use of the asset, with respect to installed capacity (maximum generation) while demand gets paid with respect to minimum demand at time of peak generation output i.e. summer nights. In all other periods DUoS charges are zero[34].

4.29 As it will be discussed later, full flexibility can be built into the pricing methodology to allow various practical implementation issues to be addressed allowing complexity of the charges to be fully controlled (location and time of use granularity can be controlled), while achieving desired revenue recovery targets.

Allocation of losses

4.30 It is understood that a number of DNOs use Loss Adjustment Factors (LAFs) to gross up demand/generation to the Grid Supply Point (GSP). These factors can be used to quantify the value of the output of generators in terms of their impact on losses. The LAFs are site and time dependent. Time dependence comes from load variations and incorporates the non-linear relationship between network flows and losses. DNOs normally define LAFs in accordance with the voltage level at which the load/generation is connected, and those values are used throughout the DNOs. Typically, values of LAFs range from 5-20% at low voltage to 2-6% in high voltage networks.

4.31 For larger users, a substitution method is used to calculate LAFs. In accordance with this method, the impact of a network user on the system losses is assessed by calculating the difference in losses when the user is connected and when it is disconnected from the network. There are a number of problems associated with this method, among which the following two give reasons for considerable concern: (i) the method can produce inconsistent results and (ii) it does not prevent temporal and spatial cross-subsidies.

4.32 On the other hand, a consistent policy for allocating series losses in distribution and transmission networks that ensures economic efficiency should be based on the evaluation of marginal contributions that each user makes to the total system losses. This method can be shown to be applicable to a fully competitive electricity market. Marginal Loss Coefficients (MLCs) for allocating active power losses in distribution systems measure the change in the total active power losses due to a marginal change in consumption or generation of active and reactive power (and hence recognising the impact of power factor on losses). Evaluation of MLCs is relatively simple as it is an extension of standard AC load flow calculations. MLCs are fully location specific and vary in time. The values of MLCs can be positive or negative indicating whether a particular user contributes to an increase or a decrease in marginal losses[35].

[34] Note that in example 2, the generator could opt to reduce its output below 35 MW during an outage of one of the lines. In this case, the flow in the remaining line would be below 25 MW, and the entire circuit would be demand dominated. Hence the demand would pay, while the generator would get paid for the use of the network.

[35] Mutale, J.; Strbac, G.; Curcic, S.; Jenkins, N, Allocation of losses in distribution systems with embedded generation IEE Proceedings Generation, Transmission and Distribution, Volume: 147, Issue: 1, Jan. 2000.

5. Distribution network pricing based on the reference network concept

5.1 This Section discusses in more detail the network pricing based on the reference network concept. The aim is to present the core features of the methodology and illustrate them on a more realistic network model.

Steps in derivation of DUoS charges based on the reference network

5.2 Figure 5.1 shows the overall process for deriving network use of system charges, which was illustrated on the two-bus examples in Section 4. The inputs into the pricing model are estimates of future demand and generation magnitudes profiles, network topology and network incremental investment costs. This is in essence network pricing based on forward-looking long run investment cost of the system. It is expected that the resultant use of system charges will be economically efficient and will deliver least cost development of the network by sending signals to network users on where to locate in the network and how to use the network By comparing critical flows in the network with existing system capacities it is possible to identify areas of over and under investment.

5.3

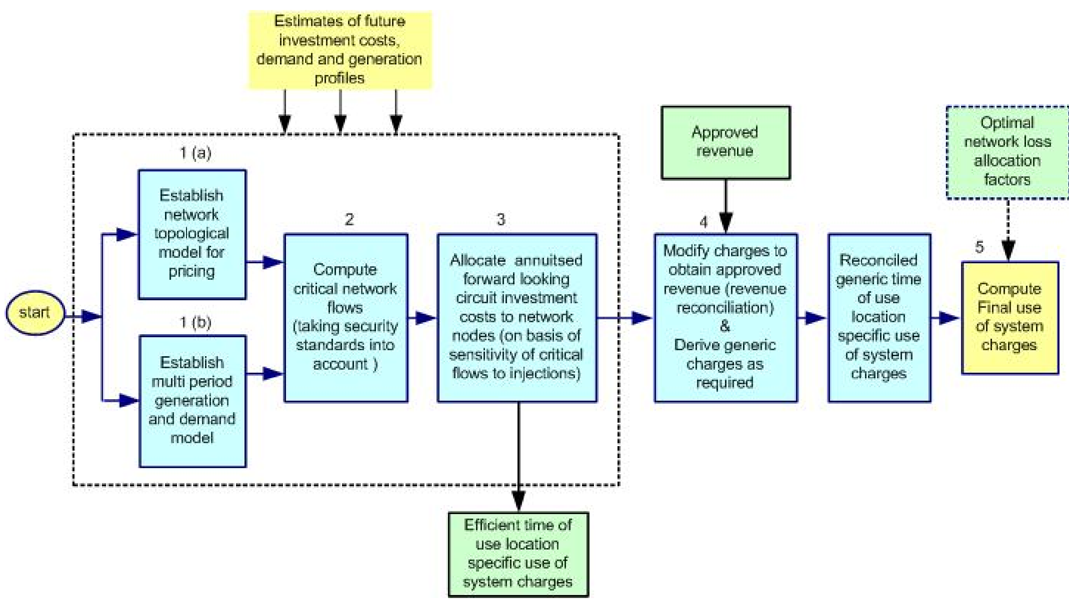

Figure 5-1 Steps in derivation of time of use location network use of system charges

5.4 **Step 1:** The process shown in Figure 5.1 starts with establishing the network topological model for pricing and the demand and generation magnitudes as well as profiles over a year or several years in the future[36].

5.5 **Step 2:** The second step is to compute the network flows for combinations of demand and generation in the identified periods (say summer and winter peak and off-peak periods), while considering *credible contingencies*, such as

[36] The process of determining future demand and generation across the network, together with an appropriate lead-time period will need to be defined.

network component outages. This step allows the critical network flows and their direction to be identified. The network, in which the capacity of each plant item is *equal* to the critical flow through it, is the reference network. The direction of critical flows is very important as it determines investment drivers in a radial system. Although in this discussion emphasis is on radial networks, the methodology can easily deal with meshed networks as well.

5.6 **Step 3:** Once the critical flows and their direction are known the annuitised forward looking circuit investment cost of the reference network can be allocated to users of the network (using the principles of marginal cost pricing). These prices are efficient and provide cost reflective signals to users regarding the impact they make on the future network costs. If the flow is upstream towards the grid supply point the asset is classified as generator dominated and entry charges for generators downstream is negative meaning that they pay for this asset during the period when the critical flow occurs. Demand gets paid. For a critical downstream flow the asset is classified as demand dominated and hence demand pays for this asset while downstream generators get paid. The output of this step is location specific time of use of system charges, which can be positive, negative, or zero.

5.7 **Step 4:** Given that the economically efficient network prices are derived from the future (reference) investment costs, there is always need to modify the charges so as to raise the allowed revenue. This process is called revenue reconciliation. Two approaches of how this can be done are discussed later in this report.

5.8 Generic charges can be computed to deal with several issues associated with practical implementation of the prices. In essence generic charges introduce flexibility in the implementation of the pricing regime. For examples a fewer set of prices can be derived instead of each node having a unique set of charges. The charges for demand and generation could be computed differently, for instance to make have all demand customers facing the same charges throughout the system while generators face locational prices.

5.9 **Step 5**: A component that allocates network losses optimally in the short term can be added to investment based pricing to produce a single network use of system price. Predefined profiles could be used rather than real time for calculation of loss coefficients. (see 4.39 – 4.41).

5.10 The network pricing model will in general include all voltage levels, as schematically presented in Figure 5-2. Although the schematic network is radial, the pricing model can indeed deal with real network topologies including complex multi-voltage meshed systems. As indicated in the figure, both generation and demand can be connected at each of the voltage levels. Superscripts (A to H) correspond to the points of connection (A corresponds to the 0.4 kV circuit, B to the 0.4kV busbar of the 11kV/0.4kV transformer, and so on).

5.11 As discussed earlier, each distribution plant, during its maximum loading can hence be characterised as being either demand dominated (design driven by *maximum* demand – secure generation contribution) or generation dominated (design driven by minimum demand- *maximum* generation conditions), depending on which of the two conditions is *critical* for its design. In case of a radial network this can also be determined by the direction of the critical flow: if the direction of the critical flow through a particular plant is downstream, i.e. from a higher voltage level towards a lower voltage level, the plant concerned is characterised as being demand dominated. Opposite is true for the generation-dominated loading of the plant.

5.12 In case that the magnitudes of the two flows are close, it may be appropriate to consider such plant as *balanced*. In this case, charges apply in both periods.

5.13 Therefore, for a radial system shown in the figure, depending on the direction of the critical flows in various parts of the network the plant concerned can be characterised as Demand Dominated, Generation Dominated or Balanced. The boundaries between the categories can be flexibly adjusted.

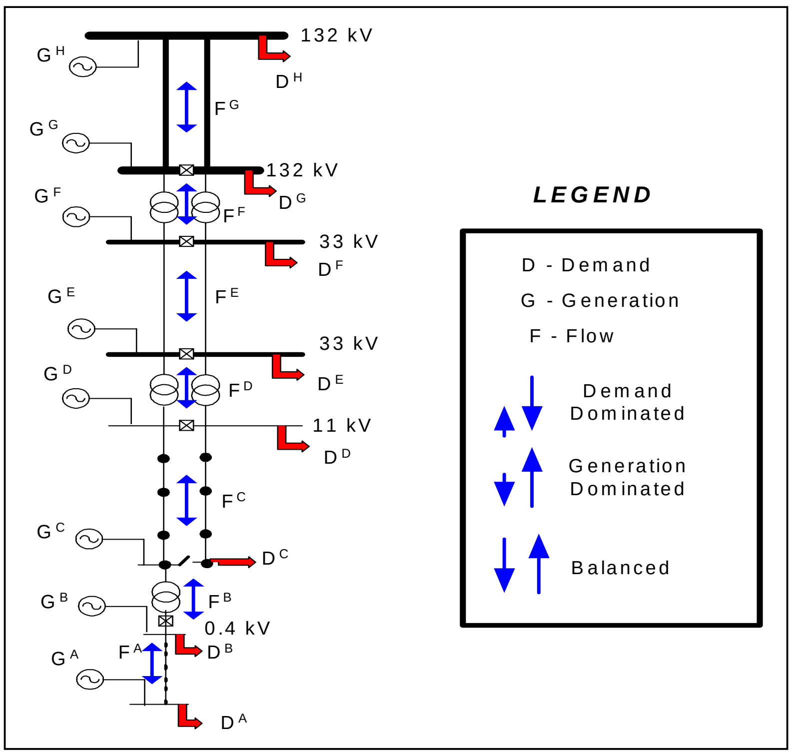

Figure 5-2Generic entry-exit network pricing model

5.14 Note that the capacity of 11 kV and 0.4 kV lines may be driven by losses rather than by the critical flow (see paragraphs 3.26 –3.32). The developed methodology can easily be adjusted to accommodate this.

Distribution network model for pricing

Network topology

5.15 The network topology for pricing is the same as for the existing network. It can also be based on future network topology where expansion of the network is envisaged.

Network costs and network charges

5.16 When allocation of costs is based on marginal cost pricing, it is only capacity dependent costs that are considered since the derivative of fixed costs is zero. One approach to dealing with this issue is to add the fixed costs to capacity dependent costs and divide the result by the capacity to obtain an average incremental investment cost. This is consistent with the requirement to have charges expressed in £/kW on installed capacity (capacity based) or £/kWh (utilisation based) or some combination of the two.

Generation and demand model

5.17 The main requirement is that all possible combinations of demand and generation to enable the most onerous flow conditions to be established should be captured. Maximum demand models alone are inadequate, as they will not necessarily capture critical flows. At the very least two periods are needed for the example representing maximum demand and secure generation output conditions and maximum generation and minimum demand conditions. It is important to note that temporal and spatial characteristics of generation and demand are critical for computation of cost reflective use of system charges with time of use and spatial discrimination.

5.18 Modelling DG contribution to network security requires at least two periods. It is advisable to specify the periods in terms of seasonal (say summer and winter) peak and off-peak and to then require demand and generation to indicate the planned performance during these periods. This will allow the different operating regimes of various DG technologies to be captured.

5.19 Note that costs are neither necessary nor required in the demand and generation model. In theory cost of generation and demand response could be modelled to determine the optimal circuit investments. Such analyses are central to assessing the net benefit of active management. This pricing methodology can cope just as well with systems with active management. The operational relationship between the network operator and the generators (and demand response) involved in active management would likely be dealt with under negotiated bilateral contracts.

Illustrative example of core features of proposed approach

5.20 The core features of reference network based pricing are illustrated on part of a radial distribution network supplied from a 132kV/33kV substation with two transformers in Figure 5.2.

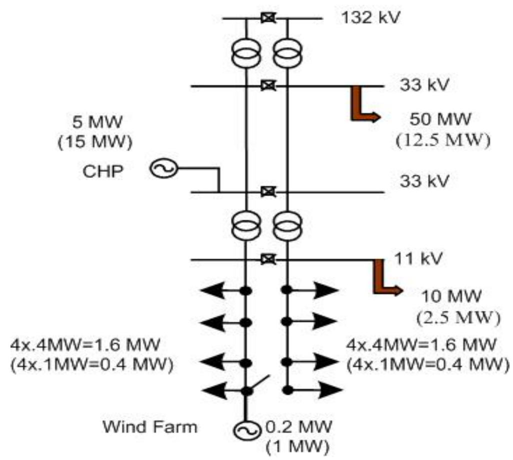

Figure 5-3 132/33kV Radial distribution system

5.21 Two 33kV out-going circuits are shown, while the rest of the 33kV network is represented by a lumped load of 50MW maximum demand, connected at the 33kV busbar. The two 33kV circuits supply a 33kV/11kV substation with two 33kV/11kV transformers. At the 33kV busbar of the substation a 15 MW CHP plant is connected.

5.22 From this substation, two 11kV feeders are explicitly represented, while the rest of the 11kV network is represented by a lumped load of 10MW maximum demand. Each of the 11kV circuits supplies four 11kV/0.4kV transformers with a maximum demand of 400kW. The LV systems can consist of microgrids and other ordinary LV networks. A Wind Farm of 1MW is connected to the circuit to the left.

5.23 In practice, a distribution network is designed to cope with the expected maximum loading condition, which likely occurs at a time of maximum demand with secure generation output. With DG, another extreme condition needs to be considered, i.e. the condition where DG produces maximum output and demand is minimum. Therefore, in this example, these two critical loading conditions are considered. The system loading is shown in Figure 5-4. The first number (without brackets) is the loading or generation during maximum demand secure generation output period and the second number (in brackets) is the loading or generation during minimum demand maximum generation period.

5.24 Since the design of the distribution networks should take into account security, information regarding the contribution of distributed generation to network capacity (security) is required. For the sake of this illustrative example, effective contribution of 5MW (33% of installed capacity) is allocated to CHP, and 200kW (20% of installed capacity) to the Wind Farm. In the context of DUoS pricing, it could be interpreted simply that the CHP and Wind Farm are capable of replacing a distribution circuit of the capacity of 5MW and 200kW respectively. This means that the firm capacities of these generators in the secure generation regimes are 5 MW and 200 kW respectively.

5.25 Minimum demand is assumed to be 25% of the maximum demand. This information is important since the condition of maximum generation and minimum demand may be critical for design/reinforcement of some of the items of plant in the network. It is important to note that the loading condition taken for the pricing calculation should be consistent with the loading scenarios taken in the network design process.

5.26 The flows in both loading conditions can be obtained by simple inspection. Critical flows are summarised in Figure 5.3. The arrow shows the direction of the flows. The critical loading of plants can be determined by the largest power flows between the two loading periods.

5.27 It can be observed that critical loading for the 11kV feeder, 33kV/11kV and 132kV/33kV transformers is driven by maximum demand, while critical loading of the 33kV circuits is driven by maximum generation, and these occur at different periods (time of use). The assets, whose capacity is driven by maximum demand condition (such as 11kV feeders, 33kV/11kV and 132kV/33kV transformers) are then classified as Demand Dominated (DD), while the 33kVfeeders are classified as Generation Dominated (GD).

5.28 Note that the critical flows determine the reference (optimal) ratings of the corresponding plant. The reference rating of 11 kV and 33 kV circuits are 2x3 MW and 2x12.7 MW respectively. Due to topology of 11 kV circuits, one feeder must cope with all 11 kV loads when one of the 11 kV feeders loses supply from the 33kV/11kV substation and the Normally Open point is closed. The optimal rating of the 132kV/33kV substation is 2x58MW. These reference ratings of the individual network components (transformers and lines at various voltage levels) can be compared with the plant ratings of the existing network.

5.29 It is important to note that the above analysis includes consideration of single circuit outages at each voltage level, which is consistent with the network planning process.

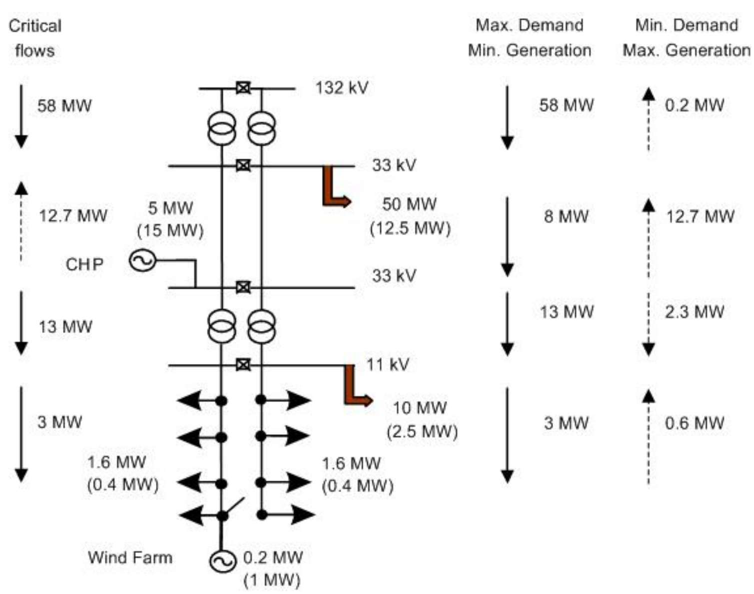

Figure 5-4 Computation of critical flows

Polarity of exit and entry DUoS charges

5.30 Given the direction of the critical flows and knowing the direction of demand and generation driven flows (Figure 5.3), the polarity of exit and entry DUoS charges can now be determined. If the direction of the critical flow in the plant coincides with the direction of the flow imposed by a particular network user, this user will be charged for the use of the plant. On the other hand, if the direction of the critical flow is opposite to the flow created by a particular user, this user will get paid for the use of the plant. This is presented in Table 5.1 and Table 5.2, for demand (exit) and generation (entry) respectively.

Table 5-1 Polarity of DUoS exit charges for demand

Load	Plant			
Connection	11 kV	33/11 kV	33 kV	132/33 kV
11 kV	Pay	Pay	Get paid	Pay
33/11 kV	0	Pay	Get paid	Pay
33 kV	0	0	0	Pay

Table 5-2 Polarity of DUoS entry charges for generation

Generation	Plant			
Connection	11 kV	33/11 kV	33 kV	132/33 kV
11 kV	Get paid	Get paid	Pay	Get paid
33 kV	0	0	Pay	Get paid

Basis for evaluation of charges

5.31 Observe that positive and negative charges for a particular user are imposed during different periods. This is because the basis for the evaluation of positive charges is different to one for the evaluation of negative charges. For example, a positive incremental change in load of the demand connected to an 11kV feeder, during the maximum demand periods, will increase the loading on the 11 kV feeder, 33kV/11kV and 132kV/33 transformers. Therefore, charges for the use of the plant concerned (DD) will be based on maximum demand of 3.2MW.

5.32 Regarding the use of the GD 33kV circuit, the relevant critical period is determined by the coincidence of maximum generation and minimum demand. Hence, demand connected at 11kV will be rewarded for the use of this 33kV circuit, based on the load during minimum demand of 0.8MW. This is illustrated in Table 5.3.

5.33 Consider now charges for the wind farm. The wind farm will be rewarded for the use of the 11kV network and 33kV/11kV and 132kV/33kV transformers and will be charged for the use of 33kV circuits. Again, the basis for the evaluation of positive charges is different to that of the evaluation of negative charges. The rewards for using the plant concerned will be based on the generator effective contribution (0.2MW). On the other hand, the charges for the use of 33kV circuit will be based on the maximum output (1MW). This is illustrated in Table 5-4.

Table 5-3 Basis for DUoS exit charges at various voltage levels

Load	Plant			
Connection	11 kV	33/11 kV	33 kV	132/33 kV
11 kV	3.2	3.2	0.8	3.2
33/11 kV	0	10	2.5	10
33 kV	0	0	0	50

Note: values are in MW unless stated otherwise

Table 5-4 Basis for DUoS entry charges at various voltage levels

Generation	Plant			
Connection	11 kV	33/11 kV	33 kV	132/33 kV
11 kV	0.2	0.2	1	0.2
33 kV	0	0	20	10

Note: values are in MW unless stated otherwise

5.34 It can also be observed that the proposed pricing approach captures correctly the interactions between network users and their composite impact on network use, and hence cost. The charges imposed to an individual user will depend on the critical loading of the plant upstream from the point of connection concerned. For example, the presence of CHP plant impacts on the charges for the wind farm and demand connected to the 11kV network (at and beyond 33kV), while the presence of the CHP plant does not impact on the charges at 11kV.

5.35 Given the annuitised cost of individual plant expressed in £/kW/year, annual charges for individual network users can be evaluated. The exit and entry charges that are calculated on this basis will be cost reflective. This is achieved by the design of charges that are location and time-of-use specific. It is important to note that the revenue accrued by imposing such charges will recover the cost of optimal plant capacity, driven by the critical flows, as presented in Figure 5.3.

Calculation and allocation of network charges

5.36 In order to evaluate network charges for individual users, per unit annuitised capacity costs (£/kW/year) are allocated to each plant in the network. For illustrative purposes, the estimate annuitised yardstick costs of 132kV circuits, 132kV/33kV transformers, 33kV circuits and 33kV/11kV transformers for typical urban network in UK were used in this example.

5.37 Given a generic entry-exit pricing model of the distribution network relevant to a particular network user, its DUoS charges can be easily evaluated by identifying the character of the upstream assets, in the sense of being demand or generation dominated. For example, a demand customer will pay for the use of all upstream assets that are demand dominated and get rewarded for the use of all upstream assets that are generation dominated. Of course, the basis for the evaluation of the corresponding DUoS charges and rewards will be different, as demonstrated previously. The opposite is valid for generation customers.

5.38 The developed entry-exit pricing model is applied to the test system. The system is presented again in Figure 5.4 with all critical loadings highlighted.

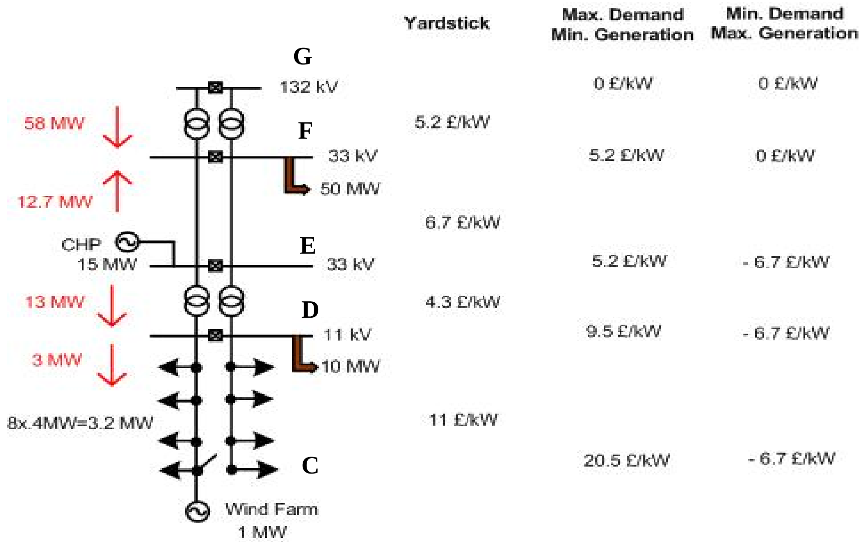

Figure 5-5 Evaluation of DUoS exit charges

5.39 Next to the network model in Figure 5.4, the estimate annuitised yardstick costs of individual plant items are presented. Furthermore, DUoS exit charges for demand customers connected at various points in the network are also listed. The polarity of charges is adopted to be positive for downstream and negative for upstream power flows respectively.

5.40 In this example the (notional) balancing point is the 132kV busbar of the 132kV/33kV substation. The balancing point chosen represents the boundary between the transmission and distribution networks and the charges at the balancing point are set to zero. However, it is also possible to have non-zero charges at the balancing point. This feature could be useful especially if it is required to pass charges from transmission to distribution network users[37].

5.41 Consider now the 132kV/33kV transformer. This is demand-dominated plant since the direction of the power flow is downstream. Hence, all downstream demand and generation customers pay and are paid 5.2£/kW/year respectively for the use of this particular plant during maximum-demand conditions while charges are zero during the minimum demand period.

5.42 The next plant to be considered is the 33kV circuit. This is a generation-dominated plant since the direction of the critical power flow is upstream. Hence, all downstream generation and demand customers pay and are paid 6.7£/kW/year respectively for the use of this plant during maximum generation condition while zero is charged during the maximum demand period.

5.43 Hence, as shown in Figure 5-5, the total DUoS exit charges for demand customers connected to the 33kV busbar of the 33kV/11kV transformer is 5.2£/kW/year applied during the maximum demand period (5.2£/kW/year for the use of the 132kV/33kV transformer and 0£/kW/year for the use of the 33kV circuit) and DUoS entry charges of 6.7£/kW/year during minimum demand

[37] The choice of a different balancing point will alter the individual charges but the price differentials between the nodes will remain unchanged.

period (0£/kW/year for the use of the 132kV/33kV transformer and 6.7£/kW/year for the use of the 33kV circuit use).

5.44 The 33kV/11kV transformer is demand-dominated plant since the direction of the critical power flow is downstream. Hence, all downstream demand customers are charged and all downstream generation customers are paid 4.3£/kW/year for the use of this particular plant during maximum demand conditions while the charges are zero during the minimum demand period.

5.45 Therefore, the total entry charges for the generation connected to the 11kV busbar of the 33kV/11kV transformer are -9.5 £/kW/year during maximum demand period (-5.2£/kW/year for the use of the 132kV/33kV transformer, 0£/kW/year for the use of the 33kV circuit and - 4.3£/kW/year for the use of the 33kV/11kV transformer) and 6.7£/kW/year during minimum demand period (0£/kW/year for the use of the 132kV/33kV transformer, 6.7£/kW/year for the use of the 33kV circuit and 0£/kW/year for the use of the 33kV/11kV transformer).

5.46 Finally, the 11kV feeder is demand-dominated plant since the direction of the critical power flow is downstream. Hence, all downstream generation customers are paid 11£/kW/year for the use of this particular plant during maximum demand conditions while the charge is zero during the minimum demand period. Therefore, the total charge for generation customers connected to the 11kV circuit is -20.5£/kW/year during on-peak period (-5.2£/kW/year for the use of the 132kV/33kV transformer, 0£/kW/year for the use of the 33kV circuit, -4.3£/kW/year for the use of the 33kV/11kV transformer and -11£/kW/year for the use of 11kV circuit) and DUoS entry charges of 6.7£/kW/year during minimum demand period (0£/kW/year for the use of the 132kV/33kV transformer, 6.7£/kW/year for the use of the 33kV circuit, 0£/kW/year for the use of the 33kV/11kV and zero for transformer and for the use of 11kV circuit). All of this information is presented in Figure 5.4.

Cash flows

5.47 The DUoS charges (assuming positive polarity for demand customers) and revenues collected from various users during peak demand and off-peak demand conditions are given in Table 5.5 and Table 5.6 respectively. The connection point G corresponds to the balancing point. Note that 58MW is imported under peak demand conditions while 0.2MW is exported under minimum demand condition from the Grid Supply Point (point G).

5.48 Note that during the peak load condition, the annual revenue is collected for all demand-dominated assets, while for the generation-dominated plant revenue is recovered during peak generation periods. The costs of the individual plant items for the reference rating are given in Table 5.7.

5.49 Observe that, in this particular case, the total annual revenue received for the demand-dominated plant is £390,500/year, as shown in Table 5-5. (This is exactly equal to the total costs of the individual plant items as shown in Table 5.7, i.e. £390,500 = £301,600+55,900+33,000.) On the other hand, the total annual revenue received from DUoS charges during the off peak demand period is £85,090, as shown in Table 5.6. This is exactly equal to the total cost of generation dominated asset shown in Table 5.7.

Table 5-5 On peak demand DUoS prices and revenues from demand and generation customer

Connection point	Price £/kW	Demand MW	Generation MW	R Demand £	R Gen £	Total £
G	0	0	58	0	0	0
F	5.2	50	0	260000	0	260000
E	5.2	0	5	0	-26000	-26000
D	9.5	10	0	95000	0	95000
C	20.5	3.2	0.2	65600	-4100	61500
				420600	-30100	390500

Table 5-6 Off peak demand (peak generation) DUoS prices and revenues from demand and generation customers

Connection point	Price £/kW	Demand MW	Generation MW	R Demand £	R Gen £	Total £
G	0	0	-0.2	0	0	0
F	0	12.5	0	0	0	0
E	-6.7	0	15	0	100500	100500
D	-6.7	2.5	0	-16750	0	-16750
C	-6.7	0.8	1	-5360	6700	1340
				-22110	107200	85090

Table 5-7 Annuitised cost of individual plant items

Plant	Yardtick £/kW	Max flow MW	Cost £
Transf 132kV/33kV	5.2	58	301600
Circuit 33 kV	6.7	12.7	85090
Transf 33kV/11kV	4.3	13	55900
Circuit 11 kV	11	3	33000
			475590

Table 5-8 Annual DUoS charges for individual network users

User	On Peak Charge £	Off peak charge £	Total Charge £
Demand connected at F	260,000	0	260,000
Generator connected at E	-26,000	100,500	74,500
Demand connected at D	95,000	-16,750	78,250
Demand connected at C	65,600	-5,360	60,240
Generator connected at C	-4,100	6,700	2,600
			475,590

5.50 The on and off-peak demand DUoS related expenditure of individual users is presented in Table 5.8. It is evident that the total annual DUoS revenue equals to the total annuitised cost of the reference network.

Revenue Reconciliation

5.51 In practice, an economically optimal distribution network is practically impossible to achieve due to various reasons such as lumpiness of investment, economies of scale, standard line and cable conductor sizes, load and generation forecast uncertainty etc. Therefore, the capacity of the existing network is likely to be higher than optimal.

5.52 Revenue reconciliation is a complex and difficult problem whose main aim is to balance revenue requirements against economic efficiency. In other words allowed revenue targets should be achieved with as little impact as possible on economic signals.

5.53 There are at least two main methods that can be used to adjust economically efficient tariffs such that the total revenue is equal to the allowable revenue. The methods, including their properties are presented and discussed in more detail below.

5.54 *Method 1 – scaling charges:* This method scales the DUoS tariff with a time specific scaling factor. This is equivalent to scaling the price of each reference network component with a time specific coefficient such that the total time specific allocated cost of the real network assets can be recovered. The properties of this method are:

(i) There are cross subsidies among customers. The difference between the amount of revenue that needs to be recovered and the cost of the reference network is allocated to customers in proportion to their initial tariff. Customers with zero tariffs are not affected by this method.

(ii) The customers in areas where the network is developing (and hence the real capacity of network components is significantly larger than the optimal capacity) are subsidised by other customers given that tariffs for all the customers are scaled.

(iii) This approach preserves the ratio between the tariffs for two customers and hence maintains the profile of the DUoS charges before the reconciliation method.

(iv) Entry and exit charges are treated equally.

5.55 *Method 2 – shifting charges:* This method applies a time specific coefficient to offset each entry and exit tariff such that the total time specific allowable cost of the real network assets can be recovered. The properties of this method are as follows:

(i) There are cross subsidies among customers. The difference between the amount of revenue that needs to be recovered and the cost of the reference network is allocated to customers in proportion to their size. All network users are affected by this method.

(ii) No cross subsidy across time of use if time specific additive factor is used.

(iii) This approach preserves the profile of the DUoS charges before the reconciliation method and also preserves the absolute initial tariff *differentials* between network users. This property may be desirable to preserve the business competitiveness between the customers especially for DG.

(iv) Entry and exit charges must be treated differently.

5.56 Revenue reconciliation should be carried out for each voltage level independently so as to prevent cross-subsidisation between different voltage levels.

Generic charges

5.57 In order to address issues related to practical implementation of the charges, generic charges are computed that enable the number of charges to be reduced to a practical level. These charges are computed after the revenue reconciliation is completed and can be considered as part of this process.

6. Implementation of Distribution network pricing based on the reference network

Complexity of network design

6.1 As discussed earlier, future network investments and the associated costs, necessary to determine efficient network prices, are the outcome of a network design (planning) exercise. In the context of the UK distribution, network design is driven by (i) the need to satisfy network design standards (security and safety standards) and (ii) a set of incentive mechanisms within the regulatory framework that may drive further investment (quality of supply, losses and incentives to connect DG).

6.2 All the network future costs driven by the above considerations should, in principle, be included in the in the determination of network prices. However, in practice the choice regarding which of the investment drivers should be included in the process will be based on the materiality of the individual cost driver and the objectives of the pricing exercise.

6.3 Assuming that the primary cost driver is network security (in line with examples considered in the previous section), network design exercise will require that the minimum rating (reference capacity) of individual plant items is determined. This will in turn require at least two loading conditions to be considered: (i) maximum demand and secure generation output conditions and (ii) minimum demand and maximum generation conditions. The larger of the two loadings will determine the plant capacity.

6.4 It is important to note that the above analysis includes consideration of circuit outages at each voltage level as appropriate, which is consistent with the network planning process.

6.5 The network design exercise could be carried out for each voltage individually as the interaction between various voltage levels, in the context of network design, is not very strong[38]. The possibility to treat various voltage levels separately could bring very significant benefits in the context of the practical implementation. It is important to stress that for the evaluation of critical network flows contingent network configurations will need to be considered.

6.6 As stated above the critical flows will be determined by performing a series of load flow computations. Load flow studies can be undertaken using an AC or DC model of the network. The choice of methodology depends on the indented use of the results. Our analysis shows that the application of DC load flow is likely to be adequate, provided that the cost driver considered is network capacity, rather than voltage considerations.

6.7 When the network is radial, the load flow is almost independent of network impedances and is determined only by Kirchhoff's current law (which states that power flowing into a node must equal the power flowing out of the node). Kirchhoff's voltage law, concerning voltage balance around a loop, is clearly less relevant for the evaluation of power flows in radial networks. This attribute

[38] For example, for designing a 132kV circuit it is sufficient to consider outages in 132kV network as outages in 33kV network and below are not likely to be material for this design task.

of radial networks enables the application of simplified load flow algorithms for computation of load flows in radial networks. This may be particularly relevant for 11kV and 0.4kV networks.

6.8 For 11kV (MV) and 0.4kV (LV) networks it also possible to simplify the tariff calculation process by adopting a modular approach to the network model for pricing. This described below

Simplified Medium Voltage and Low Voltage network modules

6.9 MV and LV networks tend in general to be more expansive than high voltage networks and furthermore data for these networks is not always readily available. While it is possible to extract the required data to carry out detailed network design for pricing for these networks the effort required to accomplish this task can be significant.

6.10 An alternative approach of addressing the data issue for MV and LV networks is proposed that significantly simplifies the data management challenges and subsequent derivation of DUoS charges for these networks. While the proposed approach trades accuracy for simplicity and less effort it retains the core features of cost reflectivity with time and spatial discrimination, which are the hallmarks of the proposed methodology for pricing of distribution networks with distributed generation.

6.11 The basic idea of the proposed approach is to classify the MV and LV networks into a finite set of network modules that represent the main characteristics of the MV and LV networks. In general MV and LV networks can be classified into any number categories to reflect particular network characteristics. For example feeders can be classified into rural and urban. These two can be further classified into demand dominated (DD), generator dominated (GD) or balanced (B). Figure 6-1 below shows basic classifications of the network

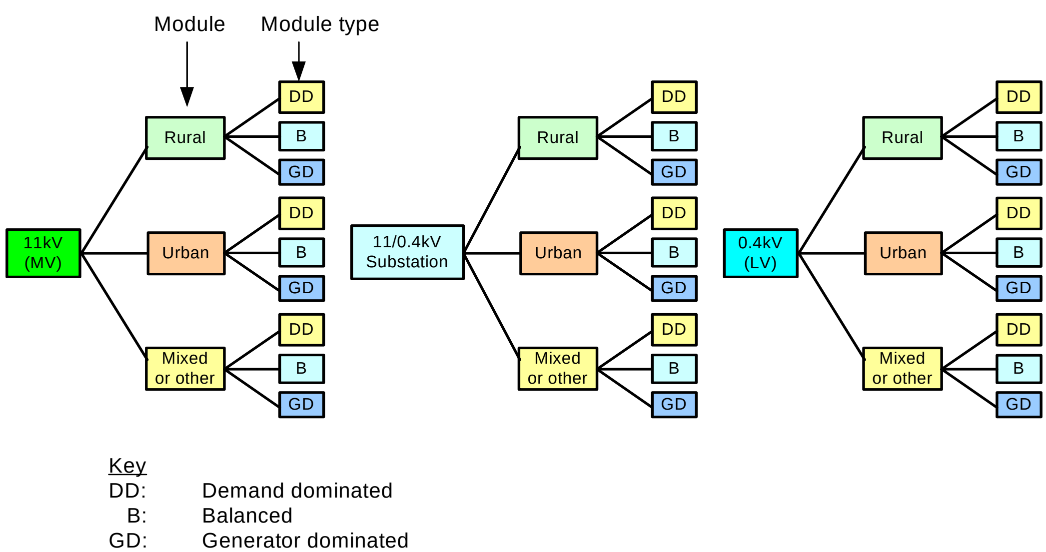

Figure 6-1 Classification of MV and LV networks

6.12 A conceptual representation of the modules is shown in Figure 6-2.

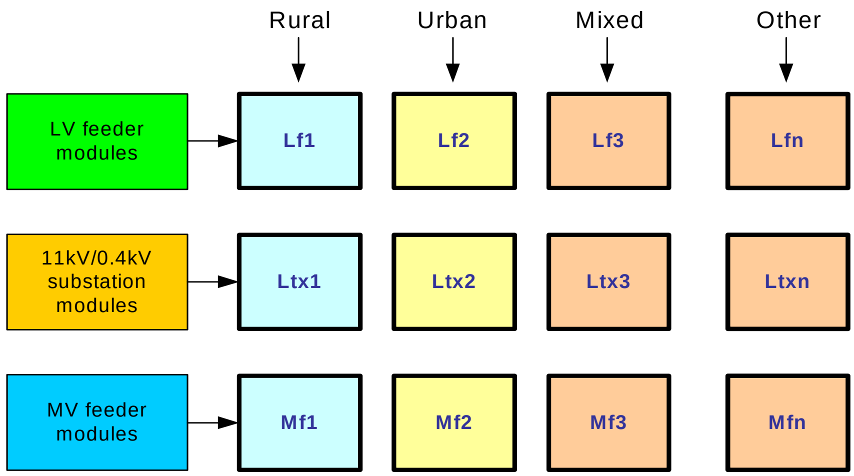

Figure 6-2 MV, LV and transformer Modules

6.13 Notice that Figure 6-2 the substations linking 11 to 0.4kV networks are shown separately as they are not considered part of either the MV or LV feeders.

6.14 The LV, MV and MV/LV substation modules will reflect specific network characteristics or attributes that are considered unique. The main attributes for LV and MV feeder modules will include circuit length, capacity, overhead or underground, type of construction, loading as well as unit costs and any other attribute deemed necessary by engineering staff. The number of modules will be dictated by engineering experience and judgement.

6.15 The modules will constitute a library from which selections will be made to create a network of the required characteristics. For example several LV feeder modules can be selected and connected to a transformer module, which in turn connects to an MV feeder module. Several MV feeder modules constructed in this way can then be linked to appropriate 33kV network points.

6.16 The key point to note is that with this approach, the MV and LV feeder as well as substation modules will already be optimised and classified as DD, GD or B. Therefore there will be no need to carry out load flow calculations. Pricing information will be derived directly from the network model constructed from the modules.

6.17 The DUoS at MV and LV network points will incorporate upstream costs from 33kV and 132kV through a tariff linking process at various voltage levels.

Granularity of tariff

6.18 A characteristic feature for which modern distribution networks are noted is their large expanse straddling several voltage levels (132kV down to 0.4kV) covering both rural and urban areas. A fully cost reflective DUoS which is location and time of use specific would imply each node in the network would have its own unique set of tariffs. While this can be achieved from a computational perspective it will not desirable from a practical standpoint[39]. It is

[39] Constraints imposed by the limitations of metering and billing systems need to be taken into consideration. Hence, the granularity of DUoS tariffs will be limited. Hence, it may not be appropriate to include the complete set of cost drivers in their full complexity, obtain a complex set of tariffs as a result (every single location having different tariff with complex time of use structure), and then carry out a

thus necessary to devise mechanism to simply the tariff for practical implementation reducing potentially hundreds of the tariffs to set of perhaps 5 or 10 per voltage level.

6.19 The resultant reduced set of DUoS charges is referred to as "*generic*" charges. Generic charges introduce cross-subsidies between nodes within the same period. However there are no cross-subsidies between different periods. In other words users who face charges in winter cannot start paying in summer as a result of generic charges.

6.20 Under a generic charge regime it is possible to compute an average charge for all demand customers while generators continue to face either full time of use, location specific nodal DUoS charges or generic nodal DUoS prices. Under such a regime there would be cross-subsidies between different periods for these customers whereas cost reflectivity would be maintained for generators.

Billing and metering issues

6.21 The tariff can be denominated in kW (power based) or kWh (energy based) or a combination of the two. A power based tariff removes the time of use feature while an energy based tariff retains this feature. Bills could be rendered on a period basis based on peak injection (entry) or off take (exit).

6.22 A power based tariff that is not time of use specific could be evaluated on the basis of the declared installed capacity of generation and load and assumed operating patterns. Note that it would desirable to disaggregate generation and demand on sites that have both.

6.23 It is important to ensure that users of the network are motivated to use the network in accordance with their predicted usage patterns (as these are used to design the network). To achieve this time of use features would be implemented and this could be based on half hourly metering. Generators contribution to security can be monitored through metering and corrections could be made depending on the discrepancy between projected and realised availability. It is also worth mentioning that energy based tariffs are less prone to gaming by users of the network and hence are likely to deliver stable income.

Stability of tariffs

6.24 It has been mentioned earlier that users of network services generally prefer stable use of system charges as they make for better planning. There are two main causes for price instability. One of them relates to the fact that under pure marginal cost pricing the use of system charge is only applied during periods when the marginal flow (or the binding flows in optimisation lexicon) occurs. Strictly speaking this rule would apply even if the difference between critical and non-critical flows were only 1 kW. Clearly strict application of this rule would be difficult to defend given that there is some error in forecasting demand and generation profile used in the calculation of critical flows. Therefore in

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process of drastically simplifying the tariffs to obtain a very small number of different tariffs. Instead, given the restrictions on the granularity of the tariffs, it may more appropriate to be selective in the process of choosing the set of cost drivers that have the most material impact on the future network cost and by doing so optimise the complexity of tariff production.

practice it would be desirable to be able to define a range within which charges would be indifferent to the direction of flow.

6.25 The second cause for price instability is rate of growth of DG deployment. In periods of high activity prices can change frequently perhaps as much as once a year or even half yearly. Some consideration would have to be given to the frequency of tariff changes. It would also be helpful to provide some information in specific areas of the network on the available headroom for investment either in demand or generation before the tariff flips over.

6.26 The issue of price stability is to a degree a matter of regulator and management choice, and an impact assessment could be carried out to inform this choice. The methodology presented is capable of dealing with whatever decisions are made with respect to these issues, for example extension of the range of flows that are characterised as critical flows irrespective of the direction of flow. This would have the effect of smoothing out the charges.

6.27 As observed earlier there is a trade off between economic efficiency and price stability. This trade off is matter for policy makers to decide.

Dealing with social issues (rural/urban tariff and cross-subsidies)

6.28 Cross-subsidies have been a feature of electricity tariffs in general for a long time. The reasons for cross-subsidies are mainly social-political, as it is considered desirable that urban and rural customers pay the same tariff (although it is recognised that rural customer impose generally higher cost than urban). The revenue reconciliation process can accommodate this requirement, while maintaining the cost reflectivity for generation, if this is considered desirable.

Phased implementation

6.29 Depending on the impact of the tariff proposals there may be need to introduce them in a phased manner. The timing and tariff levels of the phase-in would be matters for discussion/negotiation between network operators, the regulator and network users.

Cost implications of introducing new tariff regime

6.30 Network operators will inevitably incur a cost when introducing the new tariff regime. These costs would need to be assessed and planned for. The costs would include as appropriate items such as metering and billing, human resources (training), software (to compute the new tariffs), review of databases (to ensure consistency between planning and pricing information systems).

Flexible boundary between connection and DuoS

6.31 In the transition to a new DUoS tariff based on shallow connection charge policy, there are bound to be customers who have paid deep connection charges who may not be required to pay the full new tariff based on shallow connection charge. By allowing a flexible boundary between deep and shallow connection charges within the tariff structure it is possible to deal with such cases in a simple and straightforward manner. The computation of DUoS tariffs in the proposed methodology on a voltage level basis, lends itself naturally to establishing a flexible boundary by flexibly moving up and down the voltage levels.

6.32 In the proposed methodology all customers pay for the costs they drive and hence no single customer would be expected to pay for example to replace switchgear that is of benefit to all users simply because they trigger the need to have the switchgear replaced "*the who came first argument*". In this regard the boundary between DUoS and connection charges is settled naturally as an intrinsic part of the proposed methodology. In essence the methodology assumes a shallow connection charge policy. As stated above the methodology can nevertheless accommodate different boundaries between connection and DUoS as the case may be.

7. Conclusions and recommendations

7.1 This report discussed the objectives of distribution network pricing and presented a detailed exposition of network cost drivers. A pricing methodology based on the forward looking network investment cost was proposed and discussed. A set of key policy questions posed by Ofgem in the context of developing a new DUoS charging methodology for distribution networks with distributed generation was addressed and recommendations for further work outlined.

7.2 The primary objective of network pricing is to ensure economic efficiency (cost reflectivity). In the context of electrical power distribution systems, economic efficiency is concerned with sending price signals to users of the network with respect to the costs the users impose on network operation and/or development thus ensuring that in the short-term, the system is efficiently operated and, in the long-term, it follows the path of least cost development (efficient investment).

7.3 Economic efficiency is achieved by sending price signals to users of the network so as to influence their decisions with regard to (a) location in the network and (b) patterns of network use and (c) signal need for and location of new distribution network investments, i.e., encourage efficient network investment and discourage over-investment. Network pricing based on network development costs is the primary focus of this report. Given that the magnitude of losses in distribution networks is significant, it may be appropriate to allocate losses efficiently while recognising the impact of power factor on losses. This feature could be easily added to the described investment based pricing, if considered desirable.

7.4 The identification of network investment drivers is a key step in the determination of efficient DUoS prices[40]. This step represents a firm and critical link between planning standards (e.g. n-1, & P2/6), incentive schemes and network pricing. For systems with DG it is essential to take account of planning standards that recognise and quantify the contribution of DG to network security otherwise the value of DG in this regard will not be recognised and hence cannot be rewarded.

7.5 In order to ensure that the driver of investment is correctly identified it is necessary to study the spectrum of loading conditions covering periods of minimum demand-maximum generation and maximum demand - secure generation. These conditions may be influenced by the DG technology type and operating pattern. Critical network flows that drive investment are found by evaluating flows in all loading conditions to identify the highest flows.

[40] In the context of the UK distribution, network design is driven by (i) the need to satisfy network design standards (security and safety standards) and (ii) a set of incentive mechanisms within the regulatory framework that may drive further investment (quality of supply, losses and incentives to connect DG). All the network future costs driven by the above considerations should, in principle, be included in the in the determination of network prices, although in practice the choice will be based on the materiality of the individual cost driver and the objectives of the pricing exercise.

7.6 Apart from the DRM the other approaches to network pricing that have been reviewed (SRMC and ICRP) were developed primarily for application in transmission networks. The main limitation of DRM is its inability to deal with distributed generation and hence cannot be used as the basis for developing a new DUoS charging methodology for systems with DG. SRMC pricing was found to be inappropriate for distribution systems especially in the context of the UK energy market. ICRP pricing is similar in principle to the reference network pricing methodology proposed in this report for pricing the use of distribution systems with DG. Some of the key differences lie in the treatment of security and the items of plant that are included in the cost allocation. ICRP for example excludes substation costs from the allocation process while the proposed reference network methodology includes all costs. Switchgear costs, for example, can be allocated on the basis of fault current contribution and added to the DUoS computed for items of plant driven by security.

7.7 The methodology advocated for pricing distribution networks is based on the reference network concept. The methodology takes into account multi-directional power flows driven by the presence of distributed generation, network design practices specific for various voltage levels, network topology, and corresponding load and distributed generation characteristics that are relevant for driving network reinforcement.

7.8 The main attributes of the methodology include the following:

- Economically efficient (cost reflective), based on marginal cost pricing principles, DUoS charges are time of use and location specific and provide price signals to network users regarding optimal location and use of networks
- Demand and generation are treated equally (equitable)
- Captures multi directional power flows (exit and entry tariffs)
- Can handle different generation technologies (P2/6)
- Can compute generic charges making possible a controllable trade off between complexity and cost reflectivity
- Controllable cross subsidies between users (by manipulating generic charges)
- The proposed reconciliation methods will ensure that the allowable revenue is recovered
- Scientific approach (*which is auditable*)
  - Networks users' contribution to the cost of the network is calculated using scientific approach (sensitivity analysis)
- Manageable (able to handle large amount of data)
  - Every voltage level is handled separately
  - Costs from upper voltage network can be reflected in charges for downstream customers
- Rigorous and stable formulation
- Provides additional information regarding optimal network design

7.9 The proposed methodology has been explained in detail with the aid of two examples.

7.10 Migration to a cost reflective methodology of network pricing is important especially for promoting efficient integration of DG in the UK electricity networks.

7.11 Issues that may arise in the transition period will require flexibility to be built into any pricing methodology allowing for example a flexible boundary between connection and use of system charges.

7.12 The feasibility of implementation of the proposed methodology has been fully tested in a real system and found to be practical to implement. Issues of network modelling and data availability have been investigated and found to be manageable. Simplifications of networks at lower voltage levels into a small set of generic network modules have also been explored.

7.13 Answers to the specific questions raised by Ofgem in the context of this work are given in the Appendix.

Recommendations for future work

7.13 A number of issues have been identified that may benefit from further evaluation before a proposal for a new distribution network pricing methodology is finalised. These could include:

- Analysis of the materiality of individual network cost drivers and assessment of the benefits of including these in network pricing.
- Analysis of the time horizons for estimation of future demand and generation profiles that are necessary to evaluate future network costs and use of system charges.
- Analysis of the trade off between the complexity of tariff evaluation and the granularity of the tariff structure, including the appropriate balance between tariff stability (and predictability) and cost reflectivity.
- Analysis of access arrangements for DG, i.e. firmness of access of DG to distribution system, given that ER P2/5 is centered on network security from the perspective of demand, and does not explicitly deal with the level of level of availability of the network to generators. This could include an analysis of the compatibility of distribution and transmission practices in this context as transmission standards specify security of connection for generations.
- Appropriateness of including mechanisms of allocation of network losses (and constraints through active network management) in network pricing, while recognising the impact of power factor.
- Investigate the features of alternative revenue reconciliation methods in practice (e.g. shifting or scaling of network prices).
- Analysis of features of energy and capacity based tariffs including duration of time-of-use periods etc.
- Assessment of the impact of alternative network pricing approaches on future network expenditure.

8. Acknowledgements

8.1 We are grateful for the contribution and support of United Utilities in the development of the network pricing methodology presented in section 5 of this report.

9. Appendix

Responses to specific Ofgem questions

9.1 Based on the review of all the available approaches to distribution network pricing, our specific responses to Ofgem questions are given below.

1. **Q1. How to determine electricity distribution use of system charges in an economically efficient manner:**

   - *What type of charging model would you advocate, and why? What level of detail in this model would provide adequate economic messages?*

     We would advocate a methodology based on forward looking long run marginal investment pricing because the objective of network pricing is to influence future decisions of network users in terms of location in the network and patterns of network use. The methodology should take into account multi-directional power flows driven by the presence of distributed generation, network design practices specific for various voltage levels, network topology, and corresponding load and distributed generation characteristics that are relevant for driving network reinforcement. At low voltage levels generic networks could be used leaving detailed modelling for higher voltages. Such a methodology is presented in Section 5 of this report.

   - *Is the use of forward looking long run incremental costs appropriate? If so, how would these be determined?*

     Yes forward-looking long run incremental costs are appropriate because the primary objective of pricing is to achieve economic efficiency which principally requires signals to be sent to network users on where to locate in the network and when to use the network. Future costs are the ones that are relevant in investment signalling rather than past or present costs.

     Future network costs are determined from the best available estimates of planned network investments.

   - *Is it appropriate to treat demand and generation in the same manner?*

     Strictly speaking demand and generation connected at the same node should, at a particular point in time, face the same price (when one gets paid the other pays) given that the marginal impacts of demand and generation on network investment are exactly opposite. It is however recognised that demand response to price signal especially location might be more inelastic than generation.

     It is also recognised that the security requirements for demand and generation may be different. Therefore the methodology selected for application in distribution pricing must be able have the flexibility to deal with demand and generation differently in the output. Note that it is possible to develop charges that always positive for demand, but can be positive and negative for generation, as it is the case at the transmission level.

- *How are cost drivers best reflected within models?*

  Future network investments and the associated costs are driven by the network design (planning) process. There is therefore a close link between *network pricing* and *network design (planning):* network design, in a simplified form, is in fact a key input to network pricing. In the context of the UK distribution, network design is driven by

  - the need to satisfy network design standards (security and safety standards) and by

  - a set of incentive mechanisms within the regulatory framework that may influence further investment (quality of supply, losses and incentives to connect DG).

  Cost drivers are reflected through sensitivity analyses in which the marginal impact of a network user on demand for investment is determined. The marginal impact on critical flows determines whether the user drives investment or not.

2. **Q2. What is the best method of scaling model outputs to achieve regulatory revenue?**

Simple methods for scaling outputs (revenue reconciliation) include (i) additive reconciliation (shifting the prices) in which price differentials are maintained, and (ii) applying a constant multiplier the node under which price are altered so that the prices at the end give the exact amount of allowed revenue. Any of these methods can be applied and an impact assessment may inform the decision regarding preferable revenue reconciliation scheme.

3. Q3. Is there a need for an economic model:

Is marginal pricing appropriate across the entire DNO network?

In principle it is. This is not to say that there should not be mitigation measures taken in cases where fully cost reflective charges are prohibitive. Any cross subsidies should be transparent in an efficient pricing regime. The level of cross-subsidy should be a matter for both regulation and management.

Are there any constraints that need to be considered, e.g. metering?

With modern metering technology available on the market there should not be any major metering constraints in the *long run*. Metering requirements are determined by the tariff structure and billing regime. In order to ensure that users of the network adhere to declared operating patterns it is important that the users be metered either on the basis of half hourly energy injected into or taken out of the network or on maximum demand and generation over an agreed period of time.

However, as at present such metering is not used at the domestic level, the proposed network pricing methodology can be based on profiling.