Price control of Distribution

Networks

Ralph Turvey

Introduction

In its last Distribution Price Control document fixing allowed revenues for 2000-2005, OFGEM stated that its primary objectives were to strengthen the incentives on companies to increase efficiency and reduce costs, so that prices to customers can be lowered, while recognising that sufficient revenue must be raised to maintain an appropriate quality of supply, to finance required new investment and to allow an appropriate return to capital providers. It went on to admit that a system had not yet been devised which weighed quality of supply against costs; and which permitted capital and operating expenditure to be treated in such a way that overall cost efficiency could be judged without reference to the individual cost components. It hoped to improve matters by further work which was then promised and some of which has since been carried out under the title of the Information and Incentives Project. Recently, in a document describing how it intends to go about the next Distribution Price Control, OFGEM has explicitly recognised the importance of most of the issues raised in this paper.

What this paper does is, first, to describe the present system introduced by the last Distribution Price Control, and then, in the second

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1 For helpful suggestions made in response to the first draft of this paper I am indebted to Dennis Anderson, Alex Henney, Mike Kay, Stephen Littlechild, John Rhys, Graham Shuttleworth and Peter Vass
part, to examine some of these imperfections, discussing possible improvements.

**Price control 2000-2005**

The process started by establishing the capital expenditures and operating costs to be allowed during the quinquennium when determining allowed revenue. This involved forecasting output and the required investment and capital expenditures, taking account of the increases in efficiency which OFGEM deemed to be feasible. The revenue allowed on the basis of these forecasts was to be adjusted upward or downward proportionately to half the proportional deviation from the forecasts of total MWh distributed. Service quality issues and losses were treated in a way described below.

**Operating and capital costs**

OFGEM obtained projections of these two magnitudes from each of the fourteen distribution companies. After discussion and investigation it reduced the companies’ proposals for controllable operations and maintenance costs (i.e. excluding rates and NGC exit charges) by an overall annual average cumulative percentage of 2.3% over the quinquennium. It reduced the companies’ proposals for capital expenditure on average by 13% for the whole quinquennium.

**Operating costs**

The required reductions for each company were determined in two ways, which yielded very similar results.
Statistical comparisons

The first, vulgarly termed a “top down approach”, employed a simple regression analysis of “base” costs in relation to size. Size was measured as a composite variable:

\[
\text{Number of customers} \times \left[ 1 + 0.25 \cdot \frac{\text{KWh per customer - average}}{\text{average}} + 0.25 \cdot \frac{\text{Network length per customer - average}}{\text{average}} \right]
\]

The justification provided for these coefficients of 0.25 was a percentage allocation of variable costs which indicated that around 45 per cent of variable costs were driven by customer numbers, 25 per cent by units distributed and 29 per cent by length of network. As analysis by OFGEM’s consultants suggested that fixed costs should be no more than £25 million per company, the constant term in the regression analysis was constrained to that level\(^{iii}\).

A straight line was drawn from a £25 million point on the cost axis of a scatter diagram (with the other axis representing the size variable) such that all but two observations lay above it. This line was taken to be the efficiency frontier, showing efficient costs as a function of the size variable.\(^{iv}\)
Reviewing companies’ estimates

OFGEM’s second way of estimating possible efficiency improvements, vulgarly termed a “bottom up approach”, was to hire consultants to do it for them. Quoting from OFGEM’s August 1999 Draft Proposals:

In order to assess the potential savings available to each PES, a number of techniques were applied as follows:

— a cost per network kilometre benchmark of £575 per km was calculated, based on costs from four of the better PESs;
— PB Power calculated an engineering cost for each PES based on a profile of its network assets and using a best practice cost per asset;
— a comparison of historic savings achieved -- four of the better PESs achieved savings in engineering costs of up to 40 per cent from 1994/95 to 1997/98: in addition, the extent of savings in costs from 1990/91 to 1994/95 was also considered;
— PB Power undertook a review of each PES’s engineering organisational structures, field efficiency and operating practices;
PKF gathered information on the methods by which companies had reduced engineering costs over the period since 1994/95 and reviewed the methods by which companies planned to make efficiency savings in the future. Examples include the introduction of new terms and conditions of employment such as home to site working and annual hours contracts. Other examples include the increased condition monitoring of assets, the multi-skilling of appropriate staff to improve productivity, moving to best practice in the ratio of team leaders to industrial staff and the redesigning of business processes to focus on delivering outputs at minimum cost.

The different components of this analysis produced a range of potential cost savings considered by PKF to be available to each PES. The consultants then used these analyses to determine an appropriate overall level of cost savings for each PES.

Resting on the two gratifyingly similar sets of results, OFGEM set targets for controllable operating cost which required the high cost companies to move three quarters of the way towards the frontier by 2001-02 and then retain that position relative to it, a frontier which was not to be tightened from 1998-9 onwards. In order to encourage efficiency in the future, the three companies closest to the efficiency frontier were allowed an extra 1 per cent of revenue, an ex post reward which will provide an incentive for further gains in efficiency only if there is an expectation that it will be repeated.

Capital costs

Two components of capital expenditure are distinguished, load-related and non-load-related expenditure. The former is linked to the connection of new customers (partly financed by connection charges which lie outside the price control) and network reinforcement. The latter consists principally of replacement expenditure, also including expenditure on IT, environmental improvement and quality of service improvement. Increased efficiency in investment results from improved
procurement, improved design, better information about the condition of assets coupled with a shift to condition-determined replacement policies and cheaper ways of reinforcing the capacity of overhead lines.

OFGEM reduced company forecasts of their capital expenditures for the quinquennium 2001-05 by an average of 13% when it determined allowed capital expenditures. Each company was provided with a detailed description of the modelling process and benchmarking techniques adopted.

The various documents produced by OFGEM in the course of the price control review summarised the approach that had been followed.

Load-related expenditure:

Consistent relationships have been identified between growth in customer numbers and historical new business expenditure. These relationships have been used to obtain projections of future new business expenditure requirements.

In order to compare expenditure on new business between companies, company forecasts and past expenditure have been normalised by calculating the equivalent expenditure per customer using assessments of the present day value of the relevant network equipment performed for the period from 1994/95 to 2004/05.

This approach to modelling normalised new business expenditure is based on reliable information and provides results which are consistent and more robust than the regression-based method of assessing Load Related Expenditure needs used in setting the present price control. A further advantage of the present method is that it characterises individual companies [and] implicitly takes account of their underlying levels of “churn”. There is no longer a need to estimate and include these separately in the modelling.\(^2\)

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2 Dividing allowed load-related expenditure for each company for the quinquennium, annuitised at the allowed rate of return, by the forecast load growth over the quinquennium would yield OFGEM’s implicit estimates of long-run incremental costs.
Non-load-related expenditure:

Asset replacement modelling makes use of the detailed information provided by the companies in response to the business plan questionnaire, relating in particular to their asset age profiles, unit replacement costs and replacement practices; the data was supplemented by PB Power’s own information on equipment unit costs. The range of major plant and equipment categories for which asset replacement modelling was performed, was extended to include other categories of non-load related expenditure including environmental and safety related expenditure and diversions. Expenditure on metering was however excluded from the model.

The companies were benchmarked against the model by reference to their individual forecasts. Benchmarking between companies was carried out with respect to numbers of assets to be replaced and also with respect to company unit costs. By this means it was possible to identify more efficient companies and to determine the levels of expenditure expected to result from the application of best practice across all companies.

Two different criteria were examined. The first was to benchmark companies against the median performing company. The second was to benchmark at a level midway between the median and better performing (upper quartile) companies. This represents a cautious approach to assessing NLRE needs and the resulting levels of expenditure should protect system security and reliability.

A later document supplemented this information:

One approach to judging capital efficiency is to consider trends in distribution asset values over time. Companies are rewarded if the increase in the asset base between 1994/95 and 1999/00 is less than 5 per cent. They are penalised if it is greater than 10 per cent.

Another measure of capital efficiency can be derived from the relationship between modern equivalent asset (MEA) values and non-load related capital expenditure. A capital expenditure yardstick (was) calculated by allocating actual total industry non-load related expenditure (excluding metering) for the period 1995/96 to 1999/00 on the basis of the per MWh. Unfortunately the load forecasts are not to be found in any of the price control review documents issued in May, August, October and December 1999.
MEA value for each company in 1997/98. Those companies significantly below this yardstick are rewarded and those significantly above it are penalised.

**Service quality**

**Targets and incentives**

A distinction is made between Guaranteed standards and Overall standards. The former relate to the experience of individual identified consumers, so infringement of them requires that compensation payments be made to individual customers under specified circumstances. The following description is limited to the Overall standards which are formulated in statistical terms.

The Overall quality of service targets set for 2004/05 in the 1999 Distribution Price Review were derived by applying a percentage performance improvement to the ten year trend. The first four of them differed between companies, reflecting differences in companies’ past experience and circumstances. They were as follows:

1. Security of supply, defined in terms of the number of interruptions per year lasting over three minutes per 100 customers, ranging from 30.7 to 152.8;
2. Availability of supply, defined as customer minutes lost per customer per year from such interruptions, ranging from 41.6 to 195.8;
3. (for introduction in 2002) a maximum number of interruptions per year suffered by 99% of customers;
4. Percentages of supply interruptions restored within 3 and 24 hours;
5. (for introduction in 2002) 90% of telephone calls to be answered within 15 seconds (80% within 30 seconds in abnormal circumstances).

In December 2001 OFGEM, as part of its Information and Incentives Project, introduced new incentive rates to penalise poor security and availability of supply (as defined above) and poor quality of telephone response, assessed in comparison with their multi-year averages during
recent years in the last price control period. A part of the companies' revenue, limited to 2%, will be at risk depending on performance against quality standards. The 2% is made up of 1.25% for duration of interruptions, 0.5% for number of interruptions and 0.25% for telephone response. The way in which these incentives were computed can be illustrated as follows:

Example computations of the incentive rates for number of interruptions of over 3 minutes. Numbers are rounded.

<table>
<thead>
<tr>
<th>Company</th>
<th>Base level number of interruptions per 100 customers per year</th>
<th>2004-5 target level of interruptions per 100 customers per year</th>
<th>Difference of target from base level per 100 customers per year</th>
<th>Difference as % of target</th>
<th>Difference normalised by ratio of average % difference to company % difference</th>
<th>Revenue exposed, £mn.</th>
<th>2004-5 Incentive rate £mn per interruption per 100 customers</th>
<th>Number of customers, thousands</th>
<th>Incentive rate per interruption per customer</th>
</tr>
</thead>
<tbody>
<tr>
<td>TXU</td>
<td>74.9</td>
<td>68</td>
<td>6.9</td>
<td>10%</td>
<td>9.5</td>
<td>1.3</td>
<td>0.14</td>
<td>3,338</td>
<td>£4,09</td>
</tr>
<tr>
<td>London</td>
<td>36.8</td>
<td>30</td>
<td>6.8</td>
<td>23%</td>
<td>4.2</td>
<td>1.0</td>
<td>0.24</td>
<td>2,060</td>
<td>£11,56</td>
</tr>
<tr>
<td>Scottish Hydro</td>
<td>157.7</td>
<td>140</td>
<td>17.7</td>
<td>13%</td>
<td>19.6</td>
<td>0.7</td>
<td>0.04</td>
<td>640</td>
<td>£5,58</td>
</tr>
<tr>
<td>Average for all distributors</td>
<td>14.0%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Incentive rate = Revenue exposed divided by normalised difference. To express the incentive rate as £ per customer interruption, divide it by the number of connected customers and multiply by 100.

The computation involves dividing the difference between base level and target, normalised as shown in the examples, into the amount of that company’s revenue exposed to the incentive scheme to derive the penalty rate for shortfalls. The interruptions targets were derived from the 10-year linear trend in past performance, also taking into account the recent absolute level of performance. The maximum penalty will be payable for the same percentage shortfall from target for all companies.

The justification, as distinct from the derivation, of such differences in incentive rates is far from obvious.
Over-performance will be rewarded too. The rewards will be proportionate to percentage improvements over the duration of the incentive scheme in the current control period up to 15% for number and 20% for duration of interruptions. These percentage improvements will attract the maximum amounts, i.e. 0.5% and 1.25% of revenue. Basing the reward on the rate of improvement in performance overcomes the difficulty that would arise with a symmetric scheme of automatically rewarding some companies for exceeding targets, which had already been met in the last year of the previous price control.

From April 2003 OFGEM intends to set absolute targets for companies’ speed of response to telephone calls and to penalise them for shortfalls. But, already, they are to be incentivised on a relative basis for the quality of telephone response as measured by customer surveys. OFGEM will use a performance ranking for this output measure. Companies whose level of performance is below the average will be penalised and those whose performance is above the average will be rewarded.

Willingness to pay

Basing the incentive rates on consumers’ willingness to pay for quality improvement was dismissed on the grounds that OFGEM “does not consider that there is a sufficient understanding of customers’ willingness to pay to use this approach”. Two years earlier, however, they were less sceptical, quoting survey data on the financial impact on domestic, commercial and industrial consumers from interruptions according to the duration of interruptions. They used these to estimate the capitalised value of the target improvements, and compared them with the reported and forecast capitalised costs (including operating costs) of the quality of
supply measures to be undertaken to achieve those targets from 1995/96 to 1999/2000. Thus they estimated cost-benefit ratios for each company.\textsuperscript{xii}

The survey data referred to come from two papers by K.K. Kariuki and R. N. Allen (1996)\textsuperscript{xii} After piloting, questionnaires were sent by post to random samples in each of three RECs of 7,000 residential consumers, 1,700 commercial consumers and 700 industrial users. The overall response rates were, unfortunately, only 19%, 8% and 6%.

In the future, OFGEM “will consider whether there are alternative approaches for setting incentive rates, including how it relates to consumers’ valuations and the costs of making improvements in performance.” Meanwhile, however, OFGEM accepts that “there is no definitive way of calculating the incentive rates”\textsuperscript{xiii}

## Losses

A yardstick losses figure for each company was calculated by taking total GWh losses for all companies and constructing a composite explanatory variable based on GWh (70 per cent), transformer capacity (20 per cent) and network length (10 per cent). Companies are penalised by a 0.25% decrease in revenue if losses have increased and exceed yardstick losses. Companies are rewarded by a 0.25% increase in revenue if losses have fallen and are below yardstick losses. Under this scheme three of them have suffered the 0.25% decrease and six of the remaining eleven have been rewarded by the 0.25% increase.\textsuperscript{xiv}
<table>
<thead>
<tr>
<th>Company</th>
<th>Per Cent Losses 90/1-94/5</th>
<th>Per Cent Losses 96/7-98/9</th>
<th>GWh Losses 96/7-98/9</th>
<th>GWh Yardstick Losses</th>
<th>Losses Increased Above Yardstick?</th>
<th>Adjustment to Revenue Per Cent</th>
</tr>
</thead>
<tbody>
<tr>
<td>Eastern</td>
<td>6.8</td>
<td>7.1</td>
<td>2161</td>
<td>1980</td>
<td>Yes</td>
<td>Yes -0.25</td>
</tr>
<tr>
<td>East Midlands</td>
<td>6.5</td>
<td>6.1</td>
<td>1551</td>
<td>1664</td>
<td>No</td>
<td>No 0.25</td>
</tr>
<tr>
<td>London</td>
<td>7.2</td>
<td>7.0</td>
<td>1490</td>
<td>1307</td>
<td>No</td>
<td>Yes -</td>
</tr>
<tr>
<td>Manweb</td>
<td>8.7</td>
<td>8.9</td>
<td>1198</td>
<td>979</td>
<td>Yes</td>
<td>Yes -0.25</td>
</tr>
<tr>
<td>Midlands</td>
<td>5.8</td>
<td>5.5</td>
<td>1356</td>
<td>1550</td>
<td>No</td>
<td>No 0.25</td>
</tr>
<tr>
<td>Northern</td>
<td>7.0</td>
<td>6.8</td>
<td>891</td>
<td>918</td>
<td>No</td>
<td>No 0.25</td>
</tr>
<tr>
<td>NORWEB</td>
<td>6.6</td>
<td>5.6</td>
<td>1263</td>
<td>1511</td>
<td>No</td>
<td>No 0.25</td>
</tr>
<tr>
<td>SEEBOARD</td>
<td>7.6</td>
<td>7.6</td>
<td>1325</td>
<td>1212</td>
<td>No</td>
<td>Yes -</td>
</tr>
<tr>
<td>Southern</td>
<td>7.1</td>
<td>7.2</td>
<td>1910</td>
<td>1784</td>
<td>Yes</td>
<td>Yes -0.25</td>
</tr>
<tr>
<td>SWALEC</td>
<td>7.9</td>
<td>7.0</td>
<td>611</td>
<td>708</td>
<td>No</td>
<td>No 0.25</td>
</tr>
<tr>
<td>South Western</td>
<td>8.2</td>
<td>7.6</td>
<td>991</td>
<td>999</td>
<td>No</td>
<td>No 0.25</td>
</tr>
<tr>
<td>Yorkshire</td>
<td>6.3</td>
<td>6.5</td>
<td>1376</td>
<td>1415</td>
<td>Yes</td>
<td>No -</td>
</tr>
<tr>
<td>Scottish Power</td>
<td>7.9</td>
<td>7.2</td>
<td>1401</td>
<td>1321</td>
<td>No</td>
<td>Yes -</td>
</tr>
<tr>
<td>Hydro-Electric</td>
<td>9.1</td>
<td>9.0</td>
<td>674</td>
<td>662</td>
<td>No</td>
<td>Yes -</td>
</tr>
</tbody>
</table>

This represented an one-off amendment to each company's level of base revenue according to their past loss performance. This adjustment was made in addition to an existing incentive, which forms part of the price control formula as set out in the Electricity Distribution Licence (Part IV - Special Conditions). Under this incentive a company is rewarded or penalised by 2.9p/kWh (RPI-adjusted) according to whether actual annual losses are lower or higher than allowed losses. These equal the product of the number of units distributed and the average loss percentage over the previous 10 years by the number of units lost over that period.³

³ This incentive was not set out in any recent proposals documents and this part of the licence is obscuring drafted. I am indebted to Gary Keane, Distribution Policy Analyst at OFGEM for providing the explanation which should surely have appeared in some recent proposals document.
A critique

Adequate incentives

The optimal strength of incentives cannot be objectively ascertained. As the Office of the Regulator-General in Victoria has put it:

There has been considerable debate throughout the Price Review process regarding the ‘optimal’ sharing of benefits between distributors and consumers. The trade-off can be characterised as one between the size of the efficiency ‘cake’, and the share of that cake passed on to consumers. On one hand, the greater the share of the benefits distributors are allowed to retain, the greater will be their incentive to make efficiency savings, and, hence, the greater will be the extent of those savings which can eventually be passed on to consumers. On the other hand, the greater the share distributors are allowed to retain, the longer customers will have to wait before the benefits from efficiency savings are passed through to them. The carryover mechanism should provide sufficient incentive at the margin for distributors to pursue efficiency gains. That is, the benefit that distributors retain at the margin should outweigh the cost of the efficiency improvement.

There is no predetermined ‘optimal’ sharing of gains. The optimal relationship between gains retained and efficiencies achieved depends on the underlying assumptions regarding the responsiveness of the regulated businesses (in terms of cost reduction and innovation) to changes in the share of efficiency gains they retain. Importantly, the ‘optimal’ sharing ratio also depends on considerations of allocative as well as productive efficiency. The precise relationship between business efficiency responsiveness and the share of gains retained is unknown.

Distribution companies are rewarded or penalised for surpassing or falling short of cost and quality of service targets set by OFGEM. The strength of these incentives is a matter of how much, how soon and for how long a cost saving or excess or a change in service quality adds to or
subtracts from profits. Since amount and timing both count, an overall measure is provided by the present worth of the gain or loss, computed using the company’s cost of capital.

It may be thought that the strength of these incentives is independent of the strictness of the targets, provided that rewards and penalties are symmetrical. The argument is that the encouragement or discouragement to a company to do something which will change the present worth of profits by, say, £100,000 will be equally effective whether total profits are high or whether they are low (or even negative). If this is the case, then the level at which targets are set will not affect what the company does, thus having no effect upon its efficiency, but will only affect its total profits.

OFGEM has implicitly rebutted this proposition by assuming that tougher targets will result in greater efficiency and higher service quality than less demanding targets. Company management is assumed to be more ready to struggle to earn the company’s cost of capital than to maintain or increase earnings in excess of it. Avoiding a loss is thus supposed to weigh more heavily than increasing profits, implying asymmetric incentives, so that a tough target increases companies’ risk perceptions and, according to one observer, leads managers to put more emphasis on “playing the rules” and manipulating information rather than increasing efficiency.

The belief that tough targets will best stimulate efficiency gains, together with its strong aversion to allowing companies, even temporarily, to earn more than normal profits except when their performance has ascertainably been above average, makes OFGEM’s work very demanding. OFGEM has to get the targets right. This requires intensive effort to check upon the justifiability of companies’ expenditure forecasts. Consultants who possess expertise lacking among OFGEM’s
staff have to be engaged to examine and evaluate companies’ plans in
detail. This costs both time and money, all ultimately borne by the
companies each of which can pass on its pro-rata share of the aggregate
cost to their consumers. Thus the question arises whether the consultants
provide constructive advice which helps the companies to achieve greater
efficiency, or whether they simply assess the accuracy of cost estimates.
To the extent that they examine expenditure forecasts rather than detailed
plans this seems unlikely.

OFGEM has initiatedxvi an annual survey to establish the status of
asset risk management in each company by which it means “the policies
and practices adopted by companies to gather information, analyse it, act
on it and review the effects in relation to the assets that are integral to the
service performance of the network businesses” The aim is to ascertain
that key asset management activities are being undertaken effectively.
The survey will show how many companies can be classified as Leading
performers, Good performers, and Low performers by attributing scores
in the different categories of the survey model. All this hints at a doubt as
to the adequacy of the system of targets and incentives to induce the
companies to be efficient and to assure the future security and reliability
of supply. Companies argue that they have had to make decisions with a
short-term focus in order to satisfy or outperform OFGEM’s cost
allowances at the expense of the longer-term.

**Cost appraisal**

**Appraising OPEX**

It should be noted that some of the ways in which efficiency
savings were achieved in the past and, it is hoped, will be achieved in the
current quinquennium, are one-off improvements which are not
repeatable. It should also be noted that an RPI-X type of price control
does not just require the regulated industry to improve its efficiency at a rate of X% per annum. It requires its efficiency to grow X% faster than overall average efficiency in the production of the consumer goods and services within the scope of the RPI.

In the statistical top-down operating cost comparison, no account was taken of the most important cost-determining factor, namely diversified maximum demands at the various voltage levels. These determine the size of the system and hence the cost of maintaining and operating it. They would be adequately proxied by MWh only if load factors were all the same, but, as OFGEM admitted, demand data were not known. The proportions of customers and of MWh, let alone of maximum demands, at different voltage levels were ignored, as was quality of service, another factor relevant to cost.

A better measure of the sizes of distribution systems for making inter-firm statistical comparisons of operating and maintenance costs and for setting efficiency targets might be Modern Equivalent Asset valuations of them. The statement quoted above that PB Power calculated an engineering cost for each PES based on a profile of its network assets and using a best practice cost per asset suggests that this can be done. Similar approaches are followed elsewhere, and it is interesting to examine some of them.

In Denmark, the size of distribution networks is calculated as a weighted sum of line km, cable km, number of distribution transformers etc. and number of consumers, distinguishing voltage levels, with the weights proportional to operations and maintenance costs plus depreciation. There is a correction factor to allow for urban conditions, based on meters per unit length of LV line & cable. A cost index is computed by for each network by dividing its costs by net size.
In New Zealand the Commerce Commission is required to carry out a comprehensive audit of the valuations of the system fixed assets of large electricity line owners. These valuations are not required for any regulatory price determination; their sole purpose is for use in measuring performance. They are made using the optimised deprival valuation method — which estimates the losses to the owners if they were deprived of the assets and then took action to minimise their loss. Such values are the lower of (a) the replacement cost of the existing assets at Modern Equivalent Asset value, which have been optimised from an engineering standpoint and straight-line depreciated according to their age and (b) Economic Value — the maximum of the net realisable value and the present value of the after-tax cashflows attributable to that group of assets.

These optimised deprival values may be very different from current book values, which are typically based on expenditures made over the years. Optimisation consists of removing any surplus assets or excess capacity from the network configuration and the network elements, given the required level of service and network capacity. The optimised network must be designed to supply the existing load, and allowed load growth, with a quality of supply that matches the level that currently exists for each part of the network. A good current knowledge of electrical system planning is required as optimisation is concerned with the redesign of the system configuration, where the existing configuration exceeds the disclosed optimisation criteria, and not just with the replacement of individual components.

An alternative and less labour-intensive approach is being followed in Sweden, where a fictitious network is computer-designed for each distribution undertaking using only the following data:

- x/y co-ordinates for all consumers;
o consumption and load factor of each consumer;
o location of transmission supply points and any embedded
generation;
o Planned and unplanned service interruptions

Each fictitious network is designed by iteration between a net
algorithm, which creates a radial net between points, and an algorithm for
grouping points. The network consists of the connections to transmission
supply points and any embedded generation, MV lines or cables,
substations and LV lines or cables. Substation sizes and line lengths are
computed. Although the result reflects reality, there is no claim that it is
an optimal network. It provides a measure of the assets required to supply
consumers in a simple net without redundancy with a given degree of
reliability.

Cost functions for the various components are used and
assumptions are made about operations and maintenance costs as a
percentage of capital costs, the cost of capital, asset lives, fixed and
variable loss coefficients for lines and transformers, and the KWh cost of
losses. A total cost for each distributor can then be calculated, with
adjustments made in each individual case for local circumstances such as
high costs in urban areas, differences from average consumption patterns
and stony ground where cable cannot be laid

The resulting total costs provide unique measures of the service
each network provides. Dividing them into use of system revenues allows
the Authority to judge the reasonableness of use of system tariffs;
distribution companies lying well above the regression of these costs and
revenues can be singled out for further investigation. Following these two
variables through time for a single distribution company can be
illuminating, e.g. a fall in the cost measure unaccompanied by a fall in
revenue indicates a loss of consumers and higher prices paid by the remaining consumers.

**Appraising forecast CAPEX**

It is clear that OFGEM’s methods of determining allowed capital expenditures necessarily relate largely to forecasts rather than to plans. The price control review was carried out during 1999, when the latest available data related to 1997-8, while the forecasts were for the period from April 2000 to April 2005. Yet most capital expenditure on distribution is planned, costed and committed within only year or two of the time when it will be undertaken. Companies’ discussions with OFGEM and its consultants thus concerned hopes, intentions and likelihoods rather than firm commitments, so the discussions of forecasts allowed considerable scope for game playing. A company which believed that its special circumstances invalidated the application of a benchmark had to be able to explain why these circumstances were peculiar to it by demonstrating the existence of differences from the other companies. Such demonstrations may not always be possible, however, for they would sometimes require the use of quantitative data which are not available, either to the company or to OFGEM. After all, if the data were available notice could already have been taken of them in the benchmarking process.

Replacement capital expenditure can be forecast statistically using age profiles and standard lives. While actual decisions to undertake replacement will depend upon the ascertained condition of the assets concerned, the approximation to replacement expenditure in aggregate may be acceptable. Yet this supposes that the tradeoffs between asset lives and maintenance expenditure is optimal.
The distinction inherited from the past, and still used by OFGEM, between load-related and non-load-related expenditure (which includes reinforcement) is an unfortunate one. It makes evaluating expenditure plans seem simpler than it really is. When load growth requires reinforcement, the optimal choice will sometimes be to put in more capacity than is immediately required and to do it in such a way as to achieve increased security of supply. When replacement is required it may make sense do it in such a way as to increase capacity instead of replacing like with like. Forecasts of a replacement component of non-load-related expenditure based on age profiles and standard lives can therefore be misleading.

Where forecasts of capital expenditure on larger general 33KV and 132KV reinforcement schemes are concerned, a company will sketch out a quick simple solution and cost it using its own unit cost estimates, which may differ from the benchmark costs used by the consultants. Once the load growth is occurring and is seen to be permanent, then detailed plans and cost estimates will be made which may differ considerably from the first rough estimates. Meanwhile the forecasts as amended by OFGEM in the light of the consultants’ reports to it have become approved CAPEX and the determinants of what can be spent.

Consider an example of the ambiguities in the load-related non-load-related distinction that emerge once the stage of detailed planning is reached. The example is of a major scheme to reinforce a city HV and MV network where leaking oil-filled cables have created an environmental problem, too many transformation stages cause excessive losses, some substation equipment is obsolete and does not meet current safety standards, one substation has reached its capacity limit and short circuit levels are too high. One of the possible alternatives would involve constructing a new EHV/MV substation at one of two alternative possible
sites, reinforcing an existing HV/MV substation, and removing some old oil-filled cables. From a static viewpoint, assuming that everything is done at once and that there are no further changes, there are at least two other possibilities, one of which would mean switching from a radial to a mesh configuration. But when sequence and timing are brought into the appraisal the number of alternatives is multiplied. They differ in their effects upon reliability as well as cost.

Clearly an enormous amount of engineering design work is involved. To a considerable extent the consultants employed to examine planned and forecast CAPEX rely upon responses to questionnaires, supplemented by interviews with key staff and a few visits to inspect assets. However competent they are, the value of their judgments concerning the appropriateness and the projected cost of such proposed schemes will depend upon how much time they spend examining the alternatives. The same holds even for small-scale expenditures proposed for but a single purpose. Consider the relatively simple case of a 400V rural network where voltage drops exceed allowable limits. Remedying this will require reconductoring some of the lines and/or construction of new lines and/or provision of an additional MV/LV station. Seven alternative solutions have been proposed and it turns out that which of them minimises the present worth of costs depends upon the assumption made about the future rate of load growth. The consultants can hardly be expected and paid to scrutinise these solutions, audit the cost estimates and choose what rate of load growth should be assumed.

However, as already pointed out, most of the consultants’ work consists of looking at forecasts, not plans. At the time of the review, according to one company, less than 5% of its projected CAPEX was firmly planned. The result is that it is predominantly forecasts, amended by OFGEM in the light of the consultants’ reports to it, that become
approved CAPEX and thus the determinants of what can be spent. One wonders whether it would be better for OFGEM to examine plans every year instead of forecasts relating to a period ending six and a half years ahead.

**CAPEX versus OPEX**

As OFGEM is well aware there are trade-offs to be made between capital and operating costs. These involve real expenditure decisions as well as tricky questions of accounting allocations. One example is that more regular inspections and partial replacements can make overhead lines last longer before full replacement. There is therefore a danger in benchmarking capital and operating costs separately. A company may rationally choose to economise on CAPEX by spending more on maintenance. Taking account of the operating cost of the company with the lowest operating costs and the capital cost of another company which has the lowest capital costs would result in cost targets that no company could ever be expected to meet. However OFGEM admitted that a system which would allow the two to be so treated that overall cost efficiency could be judged had not yet been devised. A more coherent and predictable system for comparing different types of costs was to be sought in the future.\textsuperscript{xx} Meanwhile:

A key issue that remains to be dealt with is the trade-off between operating and network capital costs. Estimates made by the PESs typically suggest that over the period of the next price control the differences in operating costs resulting from a high network capital expenditure programme compared to a low network capital expenditure programme will be between £2 and £5 million per company per year. Savings in operating costs arising out of higher capital expenditure primarily relate to lower levels of spending on maintenance. The draft proposals suggested an adjustment for capital expenditure efficiency of up to ½ per cent of revenue. In order that companies are adequately rewarded for capital efficiency this has been increased to 1 per cent of revenue.\textsuperscript{xxi}
It is thus seen to be important not only that the incentives to achieve savings in operating costs and in capital expenditure are sufficiently strong but also that they do not distort choices between the two kinds of expenditure when there are tradeoffs between them.

Suppose that an extra CAPEX on top of the forecast total, of £100,000 with a life of forty years would result in a saving in controllable Operating and Maintenance costs of £7,070 per annum. With a regulated cost of capital of 6.5% it would just be desirable for the company to undertake that cost-saving investment since the present worth of £7,070 for forty years is £100,000. But will the system of regulation make it unprofitable?

To examine this, consider the difference between cash flows with and without that investment. The company will pay out the £100,000 CAPEX but save £7,070 per annum Operating and Maintenance costs from then until the end of the quinquennium. At the start of the next quinquennium, the Regulated Asset Value will be increased by £100,000 less the allowed depreciation of £3,000 each year until then. Thereafter, allowed Operating and Maintenance costs will be reduced by £7,070 per annum, so the firm will no longer benefit from the saving, but allowed depreciation will be increased (by £3,000 for the rest of the first twenty years and then by £2,000 for the remaining twenty years) while the allowed return on capital will be increased by 6.5% of the depreciated capital value each year. The present worth of the difference in cash flows with and without the extra investment will match its cost only if that investment takes place at the beginning of the quinquennium, so enabling the firm to benefit from the saving in Operating and Maintenance costs for the whole of that quinquennium. Is it reasonable to expect CAPEX that saves Operating and Maintenance costs to be limited to the beginning of each quinquennium?
OPEX efficiency incentives

Under the present system, improvements in operating and maintenance efficiency made during a quinquennium save the firm money, and are thus rewarded, only until the end of the quinquennium, whereupon a new level of allowed revenue will be set. This involves two drawbacks:

1. The Regulator’s decisions about allowable controllable Operating and Maintenance costs can be arbitrary. Making them can be intrusive, time consuming and costly both to the Regulator and to the regulated firms.

2. The reward to the firm from efficiency improvements is greatest when they are made at the beginning of a quinquennium.

These two drawbacks could both be eliminated by determining the Operating Expenditure component of Allowed Revenue annually as (an RPI-adjusted) moving average of actual controllable Operating and Maintenance costs over, say, the previous five years. To illustrate its working, consider a permanent reduction in Operating and Maintenance costs of £10,000 from, say, £220,000 to £210,000 starting in year 6, with a present worth at 6.5% of £153,846. This would be rewarded by an excess of allowed over actual controllable Operating and Maintenance costs for five years, averaging £6,000, as the following example shows

<table>
<thead>
<tr>
<th>Year</th>
<th>O &amp; M cost £000</th>
<th>Moving average over previous 5 years</th>
<th>Reward £000</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>220</td>
<td>220</td>
<td>10</td>
</tr>
<tr>
<td>2</td>
<td>220</td>
<td>218</td>
<td>8</td>
</tr>
<tr>
<td>3</td>
<td>220</td>
<td>216</td>
<td>6</td>
</tr>
<tr>
<td>4</td>
<td>220</td>
<td>214</td>
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</tr>
<tr>
<td>5</td>
<td>220</td>
<td>212</td>
<td>2</td>
</tr>
<tr>
<td>6</td>
<td>210</td>
<td>210</td>
<td>0</td>
</tr>
<tr>
<td>7</td>
<td>210</td>
<td>210</td>
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</tr>
<tr>
<td>8</td>
<td>210</td>
<td>210</td>
<td>0</td>
</tr>
<tr>
<td>9</td>
<td>210</td>
<td>210</td>
<td>0</td>
</tr>
<tr>
<td>10</td>
<td>210</td>
<td>210</td>
<td>0</td>
</tr>
<tr>
<td>11</td>
<td>210</td>
<td>210</td>
<td>0</td>
</tr>
</tbody>
</table>
The present worth, at 6.5%, in year 6 of this reward is £25,980, giving the company a 16.8% share of the £153,846 present worth of the postulated permanent annual saving.

An alternative possible scheme would deal only with the second of the two drawbacks of the present system noted above, namely that the reward to the firm from permanent efficiency improvements is greatest when they are made at the beginning of a quinquennium. It would reward the firm by the amount of the first five years’ savings in any controllable component of Operating and Maintenance costs even if the saving was first achieved in the last year of a quinquennium. It would do this by allowing a carry forward of the saving into part of the next quinquennium, the carry forward being allowed on top of the target level of Operating and Maintenance costs for that quinquennium. This reward to the firm of the whole of the cost saving for five years would, for a permanent cost saving of £10,000, have a present worth of £41,560, 27% of the present worth of that permanent saving.

The idea for such a scheme is not new, OFWAT applies something similar. In his Electricity Distribution Price Determination 2001-2005 of September 2000 the Regulator General of Victoria introduced carry forward, for both Operating and Maintenance costs and for CAPEX. The details of this incentive mechanism were as follows xxiii:

- an efficiency gain (loss) in operating and maintenance activities in any year is calculated as a reduction (increase) in the level of recurrent operating and maintenance expenditure, compared to the benchmark forecast expenditure for that year;
- an efficiency gain (loss) in capital expenditure is calculated as the regulatory Weighted Average Cost of Capital, multiplied by the difference in that year's capital expenditure against the original benchmark forecast. No adjustment will be included for differences in depreciation. [Adjustment would
require the Office to make assumptions about the average life of capital assets and the timing of replacement capital expenditure. On balance, it considers that including an allowance for changes in depreciation would increase the complexity of the carryover mechanism, for little overall gain, given that any bias against capital savings is not expected to be significant.

- any efficiency gains (or losses) will be retained by the distributor for five years after the year in which the gains (losses) are achieved.
- efficiency gains and losses will be treated symmetrically. In determining the overall gain or loss in any one year, the Office will look at the combined gains or losses calculated for capital expenditure plus operating and maintenance expenditure;
- a floor of zero will be set on the carryover amount in any one year, (i.e. there will be no negative carryover in any year of a future regulatory period). Where the combined carryover from operating and maintenance expenditure plus capital expenditure would be negative, the efficiency carryover will be set to zero for that year, and the implied negative value will be used to offset any positive gain in the following year;
- implied negative values will be carried over and accrued in each year, until the end of the regulatory period;
- any accrued negative carryover amount at the end of the regulatory period will be taken into account in setting benchmarks for the following regulatory period.

A method was proposed for dealing with the problem that data for the final year of a quinquennium will not be available when the carryover amount is calculated.

**Service quality incentives**

**Their scope**

OFGEM rewards and penalises companies for improved or worsened levels of service quality for which it has imposed standards. But there are other kinds of service quality where, because they cannot be operationally defined and measured, no standards are laid down. The incentives upon companies are clearly to concentrate upon those aspects
of service quality for which the regulator does impose rewards and penalties. But ideally, the system of rewards and penalties would cover all those aspects of service quality which matter to customers, it being important to cover all the dimensions of service that customer’s value.

Then there is the issue of whether companies should be penalised for incidents of poor service quality which are not their responsibility. Companies obviously cannot be incentivised to avoid Acts of God, third party damage to wires or pipes or interruptions in upstream supply from other networks. However, they can be incentivised to minimise the impact upon customers of such incidents, which they can do, at a cost, by taking precautions and by reacting to incidents swiftly. For those kinds of such events which are neither rare nor catastrophic there is therefore a case for making allowance for their average level in setting quality of service targets and allowable costs.

The way, described above, in which service quality incentives have been set was arbitrary. Fortunately, as noted earlier, in the future OFGEM will consider whether there are alternative approaches for setting incentive rates, including how it relates to consumers' valuations and the costs of making improvements in performance. Yet this appears to be a long way off, since a recent OFGEM paper is all about improving performance comparisons to enable more robust quality of supply targets to be set for the next price control period.xxv

Undesirable incentive effects

Some of the alternative possible arrangements for judging and rewarding company performance with respect to the quality of service lack desirable incentive effects.

The worst possible kind of scheme would be one where rewards and penalties depended upon a retrospective comparison of a company’s service quality performance during a period with that of other companies during the same period. In such a scheme each company would find
extreme difficulty in forecasting what might be the effect upon its future revenue of the service quality changes that it could introduce. Such schemes add to the risks borne by all companies. The award of an extra 1 per cent of revenue to the three (why not four?) companies closest to the efficiency frontier is an example of such a scheme.

Such a schemes may prove attractive to a Regulator for two reasons. One is that it absolves him from the difficult task of promulgating a justifiable ex ante target standard which requires both cost analysis and setting a value upon a change in the quality of service.

Secondly, a Regulator may err in thinking of such a scheme, with relative rather than absolute targets, as a desirable way of introducing competition. This is conceptually wrong. Competition consists of attempting to offer better value for money than rivals, that is to say of offering more bang for the buck, not of offering more bang regardless of bucks. True competition between service providers takes the form of offering different combinations of quality and price. (The winners will sometimes resemble Easyjet or Ryanair rather than British Airways.) Simply rewarding above average service quality and penalising below average service quality is to treat all improvements in service quality as desirable, regardless of cost. It would stimulate an upward spiral of expenditure on service quality improvements, regardless of the value of the resulting benefits.

OFGEM’s scheme for rewarding and penalising electricity distribution according to the quality of telephone responses is an example of a scheme which involves an assessment of a companies’ relative performance compared to its peers. The idea of doing the same with respect to the number and duration of interruptions figured in an earlier document but, fortunately, has subsequently been abandoned, at least for the current price control period 2002/3 to 2004/5. Yet OFGEM
apparently still hankers after incentivising companies “to be the best”, though if this is to be done by rewarding companies with targets that were less demanding in terms of future improvement than for companies further from the frontier, xxvii it would mean setting ex ante absolute targets, avoiding the trap of making rewards and penalties depend upon retrospective comparisons of companies’ service quality performances. However, there is here an implicit assumption that improvements will be worthwhile for all companies, even for those on the “quality frontier”. Later, however, there is mention of the intention of undertaking future work on gaining an understanding of key issues underlying quality of supply, such as whether there is a need (or desire) for continual improvement in average performance. xxviii

Benefits

Incentives can obviously influence future performance, not past performance. A company needs to be able to compare the probable future costs of a quality of service change with the effect of that change upon its future revenue. Company & customer interests are aligned if the value to customers of efficiently provided extra quality is at least equal to its extra cost. Prices should then be allowed to rise to cover the cost increase.

The marginal benefit from a higher (or lower) overall quality of service level is in principle measured as the sum of the willingness to pay of all affected consumers for an increment in that level (or the sum of the reductions in their bills that would just compensate them for a decrement in that level). Willingness to pay will naturally differ between consumers according to their circumstances, and a reservation must be accepted relating to social concern for disadvantaged consumers.

Benefit estimation is extraordinarily difficult. If ascertaining consumer valuations is to be attempted use should be made of appropriate techniques. xxix
Even when costs and benefits can be quantified there is a problem of principle. Consider the case where analysis has been applied to the choices elicited from a sample of consumers by questions about their attitudes to a few discrete payment alternatives for a specified quality of service improvement, one which would cost £x per consumer. Suppose that the analysis has revealed that:

- J consumers are not prepared to pay as much as £x for the improvement. Their total benefit might be put at £½Jx.
- K consumers are prepared to pay at least £x but not £(x+y), their total benefit can therefore be approximated as £K(x+½y).
- L consumers are prepared to pay at least £(x+y), their total benefit therefore exceeding £L(x+y) by some unknown amount.

So total cost is £(J+K+L)x and total benefit exceeds £[½Jx + K(x+½y) + (L(x+y))]. If the balance is positive, it appears that the improvement should be made. All consumers would then have to pay the £x addition to costs. But this would impose a net loss upon the J consumers, amounting to approximately £½Jx, What if they constitute a majority of the consumers? Should a Regulator seek to obtain a plutocratic or a democratic solution? This is a policy issue better faced by ministers than by the Regulator.

Despite this problems of estimation and of principle, Regulators’ decisions on service quality necessarily rest upon some comparison, explicit or implicit, between costs and their notion of benefits. Arbitrary judgments thus have to be made. Perhaps they should be made by consumer representatives; Energywatch may not be very representative, but it is surely more so than OFGEM.
Desirable incentive schemes

There are two possible incentive schemes which, while requiring such judgments, do meet the requirement of making it possible for companies to compare the probable future costs of quality of service changes with the effects of those changes upon their future revenues.

The first possibility is the approach adopted in Victoria:

In their submissions to the Price Review, the distributors were invited to submit ‘base-case’ targets with no additional expenditure for reliability improvement. They were also invited to propose ‘improvement cases’ featuring more ambitious reliability targets, in return for additional expenditure. All distributors submitted improvement cases.

In its Draft Decision, the Office proposed targets for key reliability indicators that provided for improvements in reliability of between 15 and 37 per cent over the 2001-05 period compared to expected performance in 2000. These targets were based on each distributor’s improvement scenario reflecting the preferences expressed by customers for reliability improvements over greater price reductions. The Office had also assessed the expenditure associated with these improvements as being reasonable. Some adjustments were made to the targets proposed based on the Office’s analysis of the distributors’ historical reliability performance.

Customers largely supported the reliability targets set out in the Draft Decision. In the few areas where there were differences between the Office’s proposed targets and the distributors’ proposed targets, the Office has continued to consult further with the distributors. The Office also proposed in the Draft Decision to introduce financial incentives for distributors to meet (or exceed) the service targets. These incentives took two forms: price adjustments that reward distributors for exceeding their targets and penalise them for under-performing, and guaranteed service payments to customers who received poor reliability.

It is interesting to note that comparison of the additional cost of each offer with the reduction in energy not supplied as a result of the improved reliability showed the cost of improved reliability ranged from $3,960 per MWh saved in the case of one distribution network operator to
$7,050 per MWh saved for another[^xi]. A similar variance in the marginal cost of reliability might well be found in this country.

The second possibility is the approach adopted in Norway, where no target quality of service level is determined by the Regulator. Instead he has set a reward/penalty for a future unit or percentage increase/decrease in the quality of service from its expected level. In other words, explicit benefit judgements are made and companies have an incentive to undertake service quality improvements whose costs exceed their benefits. Four values have been promulgated for energy not supplied, distinguishing notified from non-notified interruptions and residential and agricultural customers from industrial and commercial customers. The energy not supplied is estimated by applying the Fault and supply interruption tool which has been used in the Norwegian electricity industry since 1995.[^xxii]

OFGEM, as already explained, rewards and penalises the number and duration of interruptions, and thus the total number of customer hours of interruption, rather than energy not supplied, i.e. the total number of megawatt hours of interruption. Thus it treats all consumers as equal, even though a one hour interruption to a large industrial or commercial consumer’s supply may do far more harm than a one hour interruption to a domestic consumer’s supply.

### Other issues

#### Optimising losses

The retrospective yardstick approach embodied in the first part of the loss incentive described above seems rather arbitrary.

It is clearly in the social interest that, given service quality, companies should seek to minimise the present worth of future capital
expenditures plus their future operating costs plus the cost of future distribution losses. However, though the companies bear the capital and operating costs of distribution, they do not bear the cost of losses, a significant component of the total. It would be wrong to treat minimisation of the level of losses as a desirable end in itself, without regard to the relationship between the cost of losses and capital expenditure.

Consider the nature of this relationship. Its importance is demonstrated by the fact that the present worth of the lifetime cost of transformer losses can exceed the initial capital cost of a transformer. These losses depend upon the quality and quantity of iron or steel in a transformer core and the quantity of copper in the windings, so a larger initial cost will result in reduced losses. Higher performance raw materials, for transformer cores, particularly special steels and amorphous iron result in much reduced core losses. Transformer size is also relevant to losses, as they reach maximum efficiency when approximately 50% loaded. This is also the case with lines and cables, where losses are a function of the electrical resistance, which is a function of the cross sectional area of the conductor. Network losses can sometimes be reduced by reconfiguring the network to transfer loads from more to less heavily utilised sections. Alternatively, additional higher voltage infeeds provided through the installation of new substations can reduce losses. In all these cases there is a direct tradeoff between losses and capital expenditure, though not with operating costs as can be the case with capital expenditure to improve reliability improvement.

Line and transformer copper losses vary with the square of the current, so vary through time more than proportionately to changes in the load. MWh prices too vary with the level of demand, for example average
MWh APX spot prices in the first half of September 2002 for each of six time blocks were:

<table>
<thead>
<tr>
<th>Block</th>
<th>Time</th>
<th>Price (£)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Block 1</td>
<td>23.00 – 03.00</td>
<td>10.29</td>
</tr>
<tr>
<td>Block 2</td>
<td>03.00 - 07.00</td>
<td>8.96</td>
</tr>
<tr>
<td>Block 3</td>
<td>07.00 – 11.00</td>
<td>22.96</td>
</tr>
<tr>
<td>Block 4</td>
<td>11.00 – 15.00</td>
<td>26.42</td>
</tr>
<tr>
<td>Block 5</td>
<td>15.00 – 19.00</td>
<td>20.03</td>
</tr>
<tr>
<td>Block 6</td>
<td>19.00 – 23.00</td>
<td>17.30</td>
</tr>
</tbody>
</table>

Thus the demand-squared-weighted average of prices which is relevant to costing copper losses will be a good deal higher than the simple average which is relevant to costing iron losses.

These considerations should enter into the design of distribution system renewals and reinforcements. When this is done, it turns out that the optimal size of new distribution lines and cables may be such as to result in rather low optimal utilisation. Calculations which took proper account of the time-pattern of losses and prices were made for a fair-sized model generic distribution system and produced the following optimal utilisation percentages: xxxiii

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Cables</th>
<th>Overhead lines</th>
</tr>
</thead>
<tbody>
<tr>
<td>11 KV</td>
<td>28%</td>
<td>18%</td>
</tr>
<tr>
<td>33 KV</td>
<td>32%</td>
<td>30%</td>
</tr>
<tr>
<td>132 KV</td>
<td>Not driven by losses</td>
<td>33%</td>
</tr>
</tbody>
</table>

There are two possible schemes for rewarding and penalising companies for losses which would induce companies to take full account of the trade-offs between capital costs and the cost of losses when they decide upon the specifications of new plant:

1. Companies could be required to provide the losses themselves by purchasing energy to meet them, covering the cost in their tariffs and charging suppliers. They would thus cease to apply loss factors to gross up metered or estimated consumption to allow for distribution losses. This would require the companies to participate in the energy market.
might be regarded as a disadvantage. A company choosing a low-loss alternative would pay out extra CAPEX but save on the cost of losses until the end of the quinquennium. Thereafter, allowed loss costs would be reduced to a newly estimated level, so it would no longer benefit from the saving, but allowed depreciation would be increased. If, at the allowed rate of return, the extra investment were only just worthwhile, the present worth of the difference in allowed cash flows with and without it would match the extra cost only if that investment took place at the beginning of the quinquennium, so enabling the firm to benefit from the saving in the costs of providing losses for the whole of that quinquennium. Otherwise, a carry forward of the saving to allow the company to profit from it for at least five years would be required.

2. Companies could be rewarded or penalised by increasing or decreasing their allowed revenue by the cost of the difference between their actual distribution losses and a target level of losses. This is in fact what is now done, the target being set as a moving ten-year average percentage loss, with an RPI-adjusted £29 reward or penalty per MWh deviation from the moving average. This should ideally reflect expected long-term future market prices averaged for copper and iron losses (estimated by using a loss duration curve computed from a load duration curve and as a time-weighted average respectively).

This system appears to provide a considerable incentive if £29 is approximately the right amount and if companies understand it well enough to require their engineers to include the present worth of losses valued at £29 in all their economic comparisons of alternatives.

**Use of system charges**

Distribution Use of System tariffs number around 60 for most distribution companies. These charges account for a significant
proportion of final bills (about 25 per cent for a typical domestic
customer). However, OFGEM has paid very little attention to their
structure, as opposed to their general level, except in a paper published in
December 2000xxxiv. Its purpose was to identify the key issues in respect of the
methods and principles used in setting distribution charges and to assess whether in
light of recent changes to the structure and operation of the electricity industry these
methods and principles remain appropriate.

The introductory chapters curiously failed to note that the
maximum demands which it a distribution system is designed to meet are
the major determinant of distribution costs. It failed to discuss the
optimal balance between connection capacity charges, demand charges
and energy charges, distinguishing only fixed elements of charges which
reflect the costs of providing services that are typically customer related
(but which may also recover some capacity costs) and variable elements
of charges which reflect volume-related costs such as the costs of
providing, operating and maintaining certain network assets. The charges
that it quoted were all expressed as pence per KWh, though there was
mention of charging for poor power factors. This is inevitable in the case
of non-half-hourly metered customers, for whom only a fixed charge and
one or two energy charges are possible. For the suppliers of non-half-
hourly metered customers and for those customers themselves, it would
make no difference at all if the distribution use of system tariff was
expressed in terms of maximum demands or KWh, since each of their
five profiles provides a fixed ratio of the one to the other.

Matters are different in the case of half-hourly metered customers
for whom more complex tariff structures are perfectly feasible. Since
there is no description of any tariff other than tariffs for domestic
consumers, however, one is tempted to believe that the authors were
simply unaware that it is desirable for the “variable elements” of charges

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to include maximum demand charges or peak-period energy charges. (The latter have the advantage that they implicitly make allowance for demand diversity.) Some half-hourly metered supplies are in fact charged in one of these ways, for example, under Eastern Power Network’s Seven-rate Distribution Use of System tariff. Weekday consumption between 16.30 and 19.00 in November through February is charged 6 to 30 times as much per KWh as in the other six time-of-day, day-of-week and monthly periods into which the year is divided. United Utilities, on the other hand, levies annual KVA charges on some larger consumers.

The accounts of their charging and cost allocation methodologies provided by thirteen companies in the extensive appendices make it perfectly clear that, as one of them expressed it “The main cost drivers in the provision and maintenance of a supply to a customer are the voltage at which the customer is connected and the capacity/demand provision required by the customer.”

Long run marginal capital costs, then, relate to maximum demands, at the different voltage levels, adjusted for coincidence factors. Operating and maintenance costs are also demand related; they are customarily estimated as a certain percentage of capital cost. (Losses, as explained above, are the only important component of total distribution costs which are energy related.) It is clearly desirable that use of system charges should reflect the structure of marginal costs as closely as possible, subject, of course, to the constraint that they must be such as to recover a company’s total allowed revenue. (This constraint explains why the companies explain their tariffs in terms of reconciling costs derived from applying the Boley-Fowler model, reflecting the change in network costs as they are affected by changes in system maximum demand, with allocations of accounting costs.)
Marginal capacity costs can be expressed, and, as noted above, reflected in distribution tariffs, either by charges per KVA of maximum demand or probabilistically, by spreading them over potential peak hours as KWh charges. If this were done more extensively, suppliers would be induced to reflect maximum demands or peak-period energy offtakes more than at present in their contracts with their half-hourly metered customers. The resulting increase in cost reflectivity would improve allocational efficiency. However, as the Yorkshire Electricity appendix explains:

Political, regulatory and business factors have mitigated against a purist approach to tariff structures. The government at privatisation wished to avoid significant disturbance to end customers and Use of System charging structures generally mirrored the contemporaneous supply tariff structures. The basis of regulation in the distribution business is 50% volume related (i.e. GWh) - there is therefore an incentive to have charges linked to a unit basis in order to manage the under/over recovery of income.

Similarly the East Midlands appendix states that the company decided to move away in their price setting from the cost-reflective methods to a methodology where their prices and revenue streams better reflected the regulatory formula. This was done in order to minimise divergences between allowed and actual income.

It thus appears that in some cases OFGEM’s 50-50 rule is responsible for the failure of distribution Use of System charges to reflect marginal costs.

Such a failure also arises from the fact that metered or estimated half-hourly consumptions are grossed up by average, rather than marginal distribution losses. This causes the ratio of peak to off-peak Use of System charges faced by suppliers to be significantly less than the ratio of peak to off-peak marginal costs. The effect is thus that suppliers have no incentive to reflect marginal losses in tariff differentials, creating
economic inefficiency. Either of the two schemes for rewarding and penalising companies for losses discussed above would provide an incentive to set Use of System charges so as to offset this effect.

**Embedded generation**

It is tempting to assume that the injection of energy into distribution systems would reduce losses and sometimes allow the deferment of reinforcement expenditure so that, apart from shallow connection costs, new embedded generators might face negative Use of System Charges. But things are not that simple:

- An embedded generator’s output could reverse the direction of load flow, affecting voltage levels and possibly overloading some components of the network. It might sometimes have to be constrained off.
- Reactive power provision or compensation requirements may be affected.
- Fault levels may be increased, requiring uprating of upstream switchgear.
- Upstream disturbances could cause nuisance tripping of embedded generation.

Thus compensation for fault level increases, any increased losses, more complex systems for voltage control, reactive compensation and protection and the need for more active control of the distribution system could easily add to costs. Also, it may be necessary to develop a market at distribution voltage levels for balancing services or ancillary services.

The introduction of cost-reflective and incentivising charging systems for embedded generation thus poses a multitude of problems. They have been surveyed and discussed at length by OFGEM in

One proposed workstream relates to the introduction of simple standard arrangements for Domestic Combined Heat and Power (DHCP) installations and the development of pricing and charging mechanisms for them. The issues include whether net metering or separate import and export metering would be necessary, metering costs being important in the domestic market. Both would require profiling, a point on which views put forward by respondents to the consultation differed:

A research organisation pointed out that the optimum size for a DCHP unit would be around 1kW peak electrical output. This was similar to the peak diverse load of many properties. The majority of power generated would be used within the home, minimising exports. As exports would occur when the householder did not require the power, it would follow that his neighbours would be unlikely to want it at the time of export. The value of exports would be low. As exports from DCHP units would be heat-led, they would be highly amenable to profile analysis. Accordingly, it would be possible to devise metering and settlement strategies based solely on import metering, without the need to replace existing meters.

A distributed generator noted that the aim of 'net metering' was to ascertain the advance (or retreat) of a single meter register from readings at approximately three-month intervals. It was not possible to deduce from this when the generator was operating (if at all). In DCHP and PV applications the import-export condition may swing backwards and forwards several times within a 30-minute period (as appliances and thermostats switch on and off). The response suggested that class profiling based on quarterly meter readings might not be satisfactory for either import or export energy advances. Unknown and varying proportions of household consumption and generation would have been mixed together in the import-export metering process. The response concluded that there were likely to be merits in separately metering generation and consumption energies.

OFGEM stated that it regards:
the measurement of both imports and exports as a minimum for all distributed generation, including DCHP. Profiling based on the average of customer groups would seem to be insufficiently precise to allow for robust pricing. DCHP and micro-generation customers are expected to display diverse behaviours and characteristics. Metered data on import and export volumes will be essential to taking proper account of these differences.

Since half-hourly metering would be vastly too costly, it is not obvious what kind of tariff and settlement arrangements would be appropriate for DCHP and micro-generation customers. On the other hand, the introduction of profiling would encounter a chicken and egg problem: profiling rests on load research, and that requires the existence of loads which requires that DCHP consumers and a DCHP tariff and connection charge already exist.

While an averaging of costs for such DCHP consumers should be acceptable, the same will not be true, at least to start with, for larger embedded generation installations. The complications listed above are such that individual investigations of the costs imposed, or saved, by such installations would be required — these costs depend both upon location within the distribution system and upon the nature and functioning of the embedded generator. In the case of some embedded generators, interruptible connections might be economic (though it is not obvious how this would fit in with NETA.)

It is therefore apparent that the hoped-for extensive introduction of embedded generation, besides necessitating expensive work by the Distribution Network Operators on examining, costing and negotiating each individual application for connection, will entail increased difficulty in the OPEX and CAPEX forecasting required for the Distribution price control. In the long term, as the number of distributed generators increases and improved understanding is gained of the technical impact of generators on distribution networks, standard connection and Generators’
Distribution Use of System charges may become achievable, at least for smaller embedded generators.

Finally, there is the point that extensive embedded generation may make active network management necessary.

It is well known that in rural networks, the voltage rise effect is the main limiting factor for connecting embedded generation. The voltage profile in distribution networks with embedded generation can be controlled effectively within an active network environment. This would involve (i) dispatch of local generation, (ii) reactive power management and (iii) area or feeder based coordinated voltage control, including any combination of these three control strategies. In urban areas, the main limiting factor for increasing the amount of embedded generation that can be connected is increase in fault levels. A range of measures can be employed to deal with this problem, including the application of high impedance transformers, series reactors, fault current limiters and various schemes for automatic switching of the network.

Thus OFGEM will have to allow Distribution Network Operators to incur extensive costs which are not specific to the connection of individual embedded generators. It must recognise that these developments create a need for extensive Research and Development.

Research and Development

According to OFGEM, none of the companies put forward specific proposals for R & D expenditure, though some such expenditure may have been included within their cost forecasts. It is believed that the amount of research and development performed by or for the distribution companies is now significantly less than it was before privatisation. This raises the question as to whether it is currently sufficient, particularly since much work is surely needed to ascertain the best ways to meet the various challenges posed to all the companies by widespread embedded generation. Formerly, the nationalised RECs, collaborating through the Electricity Council, decided upon desirable work of value to them all,
shared its costs and were able to finance it from their tariff revenues. (Most was done at Capenhurst, now shrunken, and at Leatherhead, now closed.) A mechanism is now needed to replace this system so that collective decisions to undertake distribution research that would be of use to all distribution companies can be made and collectively financed by allowed additions to revenue. It is difficult to see how this could be achieved without some initiative on the part of OFGEM, if only to state that it will look favorably upon cost-sharing proposals.

**Concluding remarks**

1. OFGEM implicitly rebuts the economists’ simpliste belief that the strength of an incentive promising greater or smaller profits at the margin is independent of the level of profits.

2. The top-down statistical appraisal of companies’ operating efficiencies was extremely “hairy”. In any case, the residuals from such regressions reflect the effects of all excluded explanatory factors, not just efficiency differences.

3. There is admitted to be a trade-off problem regarding operating and capital cost incentives.

4. OFGEM appears to have relied very heavily on consultants for evaluating companies’ expenditure proposals and possible efficiency improvements. It is difficult to judge the reliability of their conclusions, which may have involved gaming between them and the companies, not because of doubts about their professional competence but because OFGEM’s budgetary constraints limit the effort they can deploy. An alternative approach worth exploring would be to determine the OPEX component of Allowed Revenue annually as (an RPI-adjusted) moving average of actual controllable
Operating and Maintenance costs over, say, the previous five years.

5. As regards CAPEX there is something odd about transforming forecasts into what amount to expenditure authorisations. A process of annually reviewing CAPEX plans might be a better approach.

6. Losses need to be correctly valued and treated properly as one component of the present worths of costs used to evaluate equipment choices.

7. There are several ways in which service quality incentives have been wrongly based and wrongly focused, including concentrating on relative performance and ignoring the size of interruptions. Standard rewards and penalties for changes from existing levels of energy not supplied would be preferable to setting targets that relate only to customer hours of interruption.

8. A hands-off approach by OFGEM to expenditure on distribution Research and Development may be inadequate.

9. The structure of Distribution Use of System charges relating to non-half-hourly-metered consumers requires examination; it involves issues of allocative efficiency.

10. It will take time to develop standard conditions and charges for embedded generation; meanwhile OFGEM will either have to leave them alone or apply considerable engineering resources to monitoring them. Extensive investment will be required to provide Distribution Network Operators with the ability to manage their systems actively.

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