Incorporating the Price of Quality in Efficiency Analysis:
the Case of Electricity Distribution Regulation in the UK

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Abstract

Efficiency analysis of electricity distribution networks is often limited to technical or cost efficiency measures. However, some important non-tradable aspects of their service such as quality of service and network energy losses are generally not part of the analysis. A regulatory concern is that technical efficiency can be achieved at the expense of these measures as well as allocative efficiency. Valuation of service quality for inclusion in regulatory models is particularly difficult. This paper presents an approach to measure and incorporate service quality and energy losses in analysis of technical and allocative efficiency of the utilities. We calculate technical and allocative efficiency of the 14 distribution networks in the UK between 1990/91 and 2003/04 using the Data Envelopment Analysis technique. We find that efficiency measures improved during the first (1990/91-1994/95) and second (1995/96-1999/00) distribution price control reviews and exhibited a slight decline during the third (2000/01-2004/05) review period. We find relatively low allocative efficiency - i.e. a mismatch in allocating resources among expenditures, service quality, and energy losses. The results suggest that the utilities may not be sufficiently incentivised to achieve socially optimal input bundles under the current incentive scheme.

Keywords: efficiency, Data Envelopment Analysis, electricity, quality of service, willingness-to-pay.

JEL: L15, L51, L94

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1. Introduction

Incentive regulation of the price and quality of the service of network utilities has become a topic of great relevance in liberalised electricity sectors. A current regulatory concern is how to promote cost efficiency improvements without sacrificing quality standards - i.e. regulators need to balance conflicting interests between financial expenditure, network energy losses, and minutes lost via interruptions. The aim of incentive regulation is to provide utilities with incentives to improve their efficiency and to ensure that customers benefit from the efficiency gains.

The UK regulator has used benchmarking of technical efficiency of network utilities in setting the efficiency X-factors as part of the incentive regulation regime implemented through distribution price control reviews (DPCRs). The price controls have applied benchmarking to the utilities' controllable operating costs only. Capital expenditures and network energy losses are subject to separate incentive schemes. Likewise, quality of service is subject to separate regulatory arrangements although there are potential trade-offs between cost savings and service quality (Giannakis et al., 2005). However, benchmarking without taking the price of input factors into account limits performance measurement to merely technical, rather than allocative, efficiency – i.e. how effective the utilities are in choosing the right input mix given their prices.

In designing quality regulatory mechanisms, regulators have resorted to identifying a market demand curve for service quality in terms of the desired quality level and the price customers are willing to pay for it. Previous studies attempting to quantify the value of reliability are largely based on an engineering approach (Allan et al., 1999; Kariuki et al., 1996). Most studies focus on the direct cost incurred by power interruptions rather than the value of consumer welfare loss resulting from these. From an economic perspective, consumers' valuation willingness-to-pay (WTP) to avoid power interruption reflects the social cost or price of service quality.

This paper aims to examine allocative efficiency of the UK distribution network operators (DNOs) using consumer survey data on WTP to avoid outages. We calculate quality-incorporated measures of overall economic efficiency for the 1990/91 to 2003/04 period using data envelopment analysis (DEA) technique. Section 2 provides an overview of the price and quality regulation of electricity distribution in the UK. Section 3 reviews the estimation of reliability worth in terms of outage cost and WTP. Section 4 presents the methodology. Section 5 describes the data and models used in the study. Section 6 summarises the results and Section 7 is the conclusion.

2. Regulation of Electricity Distribution in the UK

The UK's incentive regulation model based on price cap and RPI-X models has been in use for over three five-year price review periods (1990/91–2004/2005). By means of benchmarking methods, 14 DNOs with a total operating cost of £801 million (2003/04 figure) are subject to efficiency improvements in proportion to their potential for reduction in operating costs.

Under incentive regulation regimes such as price caps the regulator and the DNOs face trade-offs between capital expenditures (Capex) and operating expenditures (Opex) on the one hand and quality of service and network energy losses on the other. For example, increased spending in new equipment or more rapid response to outages can improve quality of service. Also, firms may prefer to invest in conventional transformers rather than in low-loss transformers to reduce expenditures (OFGEM, 2003b). From an economic efficiency perspective, DNOs should be subject to price of their inputs. A recent study of Polish electricity distribution firms using DEA shows that while the technical efficiency of firms increased during the transition to competition their allocative efficiency deteriorated (Cullmann et al., 2006).

In the UK, Capex, Opex, service quality, and energy loss are regulated under different types of schemes. DNOs should be subject to price of all their inputs price including that of quality of service. Currently, the DNOs are subject to an implicit price of service quality. A major challenge is for the regulator to obtain robust estimates of consumers WTP for quality. We aim to derive an explicit price for service quality from Ofgem-Accent's 2003/04 consumer survey of WTP for quality. By relating the input (customer minutes lost) to respective factor price (WTP for avoiding one minute of interruption), we measure the allocative efficiency of the utilities i.e. - how effective they are in choosing the input mix between cost and quality. The same applies to network energy losses where industrial electricity price is used as input price. In addition, cost measures of inputs such as Total expenditures (Totex) as the sum of capital and operating expenditure is used.

Our benchmarking model uses a single total expenditure measure which incorporates Totex as well as monetary values of service quality and network losses. The price of financial costs for Totex is by convention set to unity. Thus, the allocative efficiency computed by our model differs from a conventional allocative efficiency analysis where the quantity and price of all input factors are specified individually. Calculated allocative inefficiency indicates that either firms are not subject to the correct price of quality and/or that the DNOs use the wrong bundle of inputs.

2.1 Benchmarking

For the first distribution price control review (1990/91–1994/95), network charges were set while the DNOs were under state control. For the second and third price controls – i.e. 1995/96–1999/00 and 2000/01–2004/05 periods respectively – Ofgem applied the corrected ordinary least squares (COLS) technique. The regression model comprised normalised operating costs of the DNOs and dependent variable and a composite output variable (CSV), which includes – customer numbers, network length, and units of energy delivered.[1]

The COLS method was also used for the fourth price control review, without any general glide path beyond the start of the next control period (OFGEM, 2004b). Two alternative methods have been used by Ofgem (Table 1). The first makes use of a non-traditional measure of total costs based on 2002/03 normalised controllable cost and faults (NCCF) and a projected ten year average of Capex (2000-2010). The second is based on 2002/03 NCCF for 9 holding companies owning the 14 DNOs with the aim of addressing the concern of merger effect of DNOs (OFGEM 2004d). Ofgem found no superiority of the above two models over the standard base regression model which uses 14 DNOs as separate data points and regress NCCF on the CSV. Thus, in setting efficiency targets, Ofgem used the higher of the efficiency scores from standard base regression and the average efficiency score of the three alternative regression models (OFGEM, 2004d).

For the fourth price control review a revision was made to CSV and the weight of customer numbers and network length changed to 25% and 50% respectively. The units of energy delivered remained at 25% (Table 1). According to CEPA (2003), units of energy delivered are highly correlated to customer numbers (CEPA, 2003). Connected customer numbers are more relevant to supply companies rather than distribution utilities (Pollitt, 2005).

Although Ofgem adopted the COLS technique, DEA as an alternative was used for cross checking purposes (OFGEM, 2004c). Similarities were found between the results of both DEA and COLS (CEPA, 2003). The underlying theoretical robustness of Ofgem's benchmarking methods is weak and the use of integrated cost-quality benchmarking and panel data to improve the models has been suggested (Pollitt, 2005; Giannakis et al., 2005).

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[1] See Pollitt (2005) and Jamasb and Pollitt (2007) for a review of the UK's distribution price control reviews and benchmarking procedures.

Table 1: Change of dependent variable (Ofgem)

Item/Review Period	DPCR3 (2000/01-2004/05)	DPCR4 (2005/06-2009/2010)
Regression Methods	1. Base line Opex (1997/98) + Total Fault costs (14 Single DNOs) (NCCF)	1. Base line Opex (2002/03) + Total Fault costs (14 Single DNOs) 2. Base line Opex (2000-2010) + Total Fault costs (9 ownership groups) 3. Total Opex (2002/03) + Average Capex (2000-2010)
No. of Regressions	1	3
Composite Scale Variable		
Customer Number	50%	25%
Network Length	25%	50%
Unit of Energy delivered	25%	25%

2.2 Regulatory Criteria of Quality in the UK

Starting about the same time as the first price control, guaranteed and overall standards of performance were set for Public Electricity Suppliers (PES) in order to maintain and improve the levels of customer service. Later, the concept of PES was replaced by licensed DNOs with the introduction of the Utilities Act 2000. New distribution standards were put in place following the separation of distribution and supply businesses in 1999. As part of the quality measures, these standards mere maintained and amended during subsequent years and guaranteed standards (GS) of performance covered 12 aspects of service in 2005. New standards were added to address power supply restoration under medium, large, and very large severe weather conditions and apply to the Highlands and Islands of Scotland. Multiple interruption standards were introduced to protect the worst served consumers (OFGEM, 2005). If DNOs fail to meet these standards, compensation at fixed rates is payable to the customers concerned, subject to certain exemptions. Failing to achieve the overall standards (OS) had no financial implications. The OS of performance including the standards such as the fulfilment of new connections, fixing voltage complaints were revoked in 2005. Some key reporting requirements will be retained as part of the outputs reporting framework. Ofgem will re-introduce overall standards if there is notable deterioration in reported performance.

Several measures related to quality enhancement including the incentive scheme for quality indicators, multiple interruptions standards and DNOs’ performance comparison improvement were initiated in the second price review. Tackling the inherent lack of standardisation of company reporting of quality with respect to network design and customer density is an ongoing process (OFGEM, 2004b). From the end of the second price review, DNOs have been required to supply disaggregated performance data on quality which gives a better picture of how different parts of a company's network perform. Starting from the fourth price control review period (beginning in 2005), the overall measures of quality and penalties/rewards under the incentive scheme are reported by Ofgem in its quality of service report. A new Guaranteed and Overall Standard Performance (GOSP) report published by Energywatch covers the guaranteed and overall standards of performance.

Two important quality indices are the number of customers interrupted per 100 customers (CI) and the customer minutes lost per connected customer (CML). Between 2001 and 2003, the average CI has fallen from 83.1 to 75.3 while the average CML has dropped from 79.7 to 71.1 minutes (OFGEM, 2004d). An analysis of data between 1991/92 and 2003/04, showed a correlation coefficient of 0.86 between CI and CML.[2] It is noteworthy that, in individual cases, improvement made in CI does not necessarily guarantee an improvement in CML. Ofgem assigns a higher incentive percentage for DNO to achieve CML than CI target, which shows the relative importance of reducing the length as opposed to the number of interruptions. Thus, the focus of this study is on customer minutes lost.

2.2.1 Information and Incentive Project (IIP)

IIP was first introduced in 1999, is the blueprint on service quality improvement (OFGEM, 1999a). The project was aimed at reinforcing the delivery of the quality and incentivising firms to improve efficiency. Under Ofgem's initiation, independent auditors British Power International (BPI) and Mott MacDonald (MM) developed a framework in 2001 with the aim of identifying potential inaccuracies in incident reports made by DNOs. The accuracy of data has been improving over the years. According to BPI, the minimum requirement of reporting accuracy on Overall CI and CML is 95%, and so far the result has been above 90% (BPI, 2003).

The establishment of Regulatory Instructions and Guidance (RIGs), which was in its version 5 in 2005, makes for a clearer and more feasible reporting framework (OFGEM, 2005a). On-going

[2] The data for 1990/91 is excluded due to the presence of an exceptionally high CML figure.

improvements include clarifying ambiguities in calculating the number and duration of interruptions and re-defining the re-interruptions. However, some controversies remain. For example, the negotiation continues on a more accurate definition and measurement of distribution losses since its initial consultation in 2003 (OFGEM, 2003b).

2.2.2 Incentive Scheme for Quality

The IIP incentive mechanism did not come into operation until April 2002. A two-sided incentive scheme of penalties and rewards aiming at quality indicators was introduced. As shown in Table 2, financial penalties up to 1.75 percent of revenue annually are imposed on distribution firms which fail to meet quality of service targets in the third review period. Rewards are available for firms which exceed the targets for 2004/05 based on their rate of improvement in performance up to that date (OFGEM, 2001a). The mechanism also included a commitment to rewarding frontier performance in the next (now current) price control period. The quality of telephone response was based on annual reward or penalty up to a maximum of 0.125 percent of revenue in the third price control period. However, as set out in Ofgem’s document, it was not feasible to expose any revenue to the speed of telephone response measure during DPCR3 due to the inconsistencies in measuring this output among DNOs (OFGEM, 2003e).

Table 2: Incentive scheme for quality of service

Incentive arrangement	**Third Distribution Price Control Review (2000/01-2004/05)**	**Fourth Distribution Price Control Review (2005/6-2009/10)**
Interruption incentive scheme	+ 2% to -1.75%	+/- 3%
Storm compensation arrangements	- 1%	- 2%
Other standards of performance	Uncapped	Uncapped
Quality of telephone response	+/- 0.125%	+0.05% to -0.25%
Quality of telephone response in storm conditions	Not applicable	0 initially +/-0.25% for 3 years
Discretionary reward scheme	Not applicable	Up to + 1m pounds
Overall cap/total	+ 2% to -2.875%	4% on downside No overall cap on the upside
Adapted from OFGEM, Electricity Distribution Price Control Review, Final Proposals, November 2004, (OFGEM, 2004d); OFGEM, Information and incentives programme: Proposed amendments to the Regulatory Instructions and Guidance for the speed of telephone response, July 2003, (OFGEM, 2003e).		

For the third price control review, the exposure of firm's revenue to quality incentives was limited to 2% in each year. This was made up of 1.25% for duration of interruptions, 0.5% for number of interruptions and 0.25% for telephone response (1.25% + 0.5% + 0.25% = 2%). In 2002/03 and 2003/04 the scheme was penalty only, the reward element for CIs and CMLs was introduced in 2004/05. For the fourth price control period, service interruption incentive increased from 2% to 3%. The down-side exposure is capped at 4% and there is no overall cap on the up-side. The above changes were also to reflect the consumer willingness-to-pay survey results into consideration (OFGEM, 2003e; 2004d).

Setting appropriate incentive rate is critical while there is no definitive way of calculating it (OFGEM, 2001a). Ofgem's formulae for calculating the incentive rate is detailed in Appendix I. Each DNO is set an incentive rate for CI and CML, ranging from £0.04 million to £0.25 million and £0.04 million to £0.27 million respectively for 2004/05 (OFGEM, 2001). Ofgem has set tougher targets to minimize CI (a 5% improvement) and CML (a 12% improvement). Targets will include 50 percent weighting on pre-arranged outages under the new scheme. This aims to avoid perverse incentives to accelerate or delay network investment depending on quality of supply performance to date in a given year (OFGEM, 2005). The rewards are calculated in proportion to the percentage improvement in the number of interruptions (PICI) and duration of interruptions (PICML) relative to the base year. For the maximum reward level, firm performance must have improved at least 15 per cent over base level performance on the number of interruptions, and at least 20 per cent over base level performance on the duration of interruptions. Firms receive a smaller, pro-rata amount if they exceed the targets but have improved by a smaller percentage amount (OFGEM, 2001c).

The number of interruptions confirmed by Ofgem that arose on other networks outside the DNO's control will be excluded from the measurement against the targets. However, 10 percent of the duration of interruptions on other networks will be included in assessing performance as it is within DNO's ability to take appropriate actions to mitigate the duration. Changes in definition including short interruption, re-interruption to supply and incident start time have recently been made.

Table 3 shows the reward and penalty amount imposed on DNOs. Using the new scheme according to a more stringent standard leaves the revenue exposure totally insignificant when compared to the 2003/04 base figure of total willingness to pay for one minute avoidance of power interruption. Based on our calculation, the business WTP is £22.8 million while the domestic WTP is £17.5 million, which in total is around £40 million for 2003/04 (OFGEM, 2004a; 2004d). The figure for total customer minutes lost for that year is 71.11 minutes, the total social interruption cost is around £2.8 billion, almost 24 times the maximum penalty (OFGEM, 2004d).

Table 3: Revenue and profit exposure (first year of DPCR4) (2002/03 prices)

Year/ Items	Allowed Revenue (£ million)	Revenue Exposure * (%)	Max. Penalties (£ million)	Allowed Profit (£ million)	Profit Exposure * (%)
2005/06	2998.3	4%	119.9	861	13.9%
* Compensation not included; DPCR4 2005-2010					

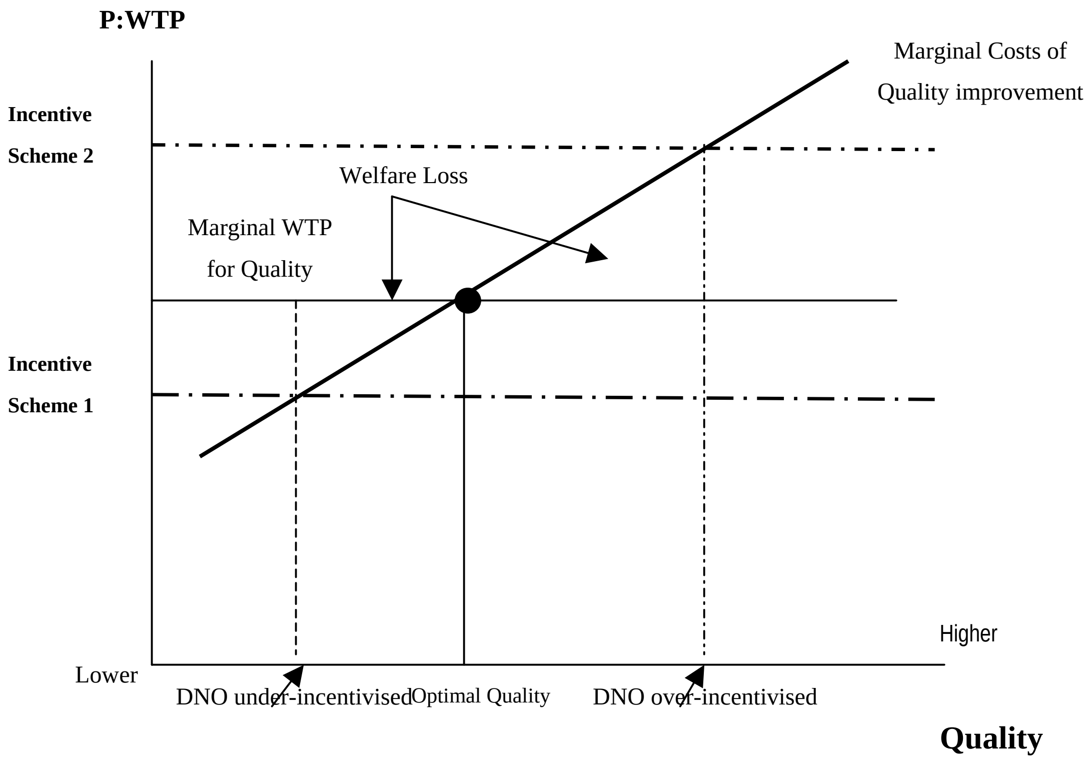
In principle, utilities should be incentivized to provide optimal quality level where the marginal benefit of an extra unit of quality is equal to its marginal cost. In order to link up incentive payments to social costs and benefits of quality, the incentive target could be set using marginal cost of quality improvement as a lower bound and consumers' marginal WTP as an upper bound. Basing the reward merely on the marginal cost of improvement will not provide utilities with sufficient incentive for quality improvement.

In contrast, if the reward is based on the marginal WTP (marginal benefit of quality improvement), utilities have incentive to improve their quality to the optimum level. However, a concern in adopting such an approach is that utilities would provide service at a sub-optimal level but capture the consumer surplus from their monopoly position. In order to address this concern, an incentive scheme consisting of a sliding scale of rewards could be introduced, whereby the utilities have to reach a specified level of quality in order to receive the reward.

As demonstrated in Figure 1, ineffective incentive schemes send incorrect economic signals to the utilities and result in either under-supply or over-supply of quality. Higher or lower than optimum levels of quality will result in a welfare loss. Figure 1 also shows the relationship between marginal cost of quality improvement and marginal WTP - i.e. the marginal benefit of quality improvement received by the customer (Ajohia et al., 2005). Higher quality level is generally associated with higher marginal cost of quality. This might require, for example, sophisticated equipment and under-grounding which come at a higher cost. In addition, the marginal cost of improving quality varies across DNOs.

Figure 1: Concept of social optimal quality

Source: Adapted from Ajodhia (2005)



2.3 Electrical Losses

Network energy losses can be categorized as (fixed and variable) technical losses and non-technical losses (measurement errors and un-metered supplies). Reducing technical losses contributes to a reduction in CO_2 emissions. However, reducing costs to consumers requires a reduction in both types of losses. Electrical losses average to six percent of electricity distribution in the UK (OFGEM, 2003b; 2003d).

Each DNO is assigned a yardstick loss figure. This figure is arrived at by taking total losses (GWh) for all DNOs and making a composite explanatory variable based on GWh (70%), transformer capacity (20%) and network length (10%). Financial penalties up to 0.25 percent of revenue annually are imposed on firms if losses have increased and exceeded yardstick losses. Firms are rewarded if losses have decreased and are below yardstick losses (OFGEM, 1999b). Financial rewards (penalties) at 3 pence per kWh have been applied to the difference between actual losses and the target level of losses based on a historic benchmark (OFGEM, 2004).

From the fourth price control period, for every kWh of loss reduction (increase), DNOs are rewarded (penalized) at a rate of 4.8 pence per kWh (in 2004/05 price). Loss targets for the DNOs range between 4.96% and 8.73% (OFGEM, 2004d). The target level of loss is based on a proportion of units distributed and is fixed for five years. The fixed target is based on the historic performance of the DNO, as measured by the average proportion of energy lost between 1994/95 and 2003/04. A rolling retention mechanism is in place to ensure that DNOs receive full benefit of incremental improvements in performance for a period of 5 years.

3. Economic Worth of Reliability

3.1 Estimation of Outage Cost

Cost of outage is the most commonly used measure of service reliability. A number of studies have addressed different methods of measuring outage costs. Direct cost methods such as the direct financial evaluation approach, the gross economic indices approach (GNP divided by total electricity consumption), and the case study approach has been employed frequently in the past. Price of electricity has also used to provide a lower bound on outage costs (Caves et al., 1990). It provides no additional information, but represents the cost of foregoing the last increment of consumption at any time.

Indirect cost method, on the other hand, is based on the economic principle of substitution. For example, the cost of purchasing back-up generators is used to convert to outage costs (Bental et al., 1982). Another measure cost, Value of Lost Load (VOLL), is derived from a 1978/79 survey of willingness-to-pay to avoid power cuts to 824 households in Finland. In the UK, VOLL was set administratively at £2.0/KWh in 1990 and was adjusted according to inflation. Based on the indirect evidence using price elasticities, the VOLL figure is probably underestimated (Newbery, 1998). VOLL is problematic in its calculation as it neglects the inherent characteristics of the UK network such as geographic area, customer mix, and weather conditions (Kariuki, 1996). The proxy used in the above methods for cost estimation often neglects the type of customers affected. Productivity loss and damage to equipment in monetary terms may be relevant to commercial customers but not to residential customers where inconvenience or leisure loss needs to be valued in line with consumer theory.

3.2 System Customer Outage Costs (Ofgem)

The System Customer Outage Costs (SCOCs) approach used by Ofgem to estimate the financial impact of interruption and hence cost-benefit ratios for each DNO was developed in 1999. SCOCs are based on the costs that customers might incur during an interruption in supply and are derived from Sector Customer Damage Functions (SCDFs), the number of interruptions, interruption durations, and the system customer mix (OFGEM, 1999c). SCDFs are evaluated from the weighted Customer Interruption Costs (CICs) (Allan et al., 1999). The CICs are obtained through customer surveys by means of a mailed questionnaire which uses the preparatory action method (PAM). This method aims to investigate the costs customers would be likely to incur if their electricity supply were interrupted for a given duration of time. On the basis of hypothetical scenarios: (20 minutes, 1-hour and 4-hour monthly interruptions occurring after 4:00pm on winter weekdays, and 4-hour weekly interruptions occurring after 4:00pm on winter weekdays), customers are asked to choose from a given list the actions they would take in order to minimize the impacts of such interruption. The hourly costs of each action are noted alongside the list of actions.[3] The costs of the chosen actions are then totalled in order to represent the customer interruption costs.

A shortcoming of this type of estimation is it equates the direct cost of an action incurred from a power interruption to the value of the interruption to customers. Without considering the value of utility losses to consumers, Ofgem's approach (SOSC) is likely to significantly under-estimate the actual outage cost. This survey was quoted again in a recent Ofgem's report (OFGEM, 2002a). From an economic perspective, the welfare effects of a single outage, the lost utility to customers is equivalent to the sum that they would be willing to pay to avoid a power interruption. Normally, consumers should be assumed to make rational choices to maximize their expected utility and are willing to pay money to secure an improvement in services which make them better off (welfare). Consumer surplus can be expressed in either WTP or willingness to accept compensation measure. Thus, the WTP reflects the real economic valuation of improved services by taking consumer's utility into consideration. Regulators should attempt to quantify the value of quality of service based on consumers' preferences instead of the direct system cost, as this is more closely in line with economic theory.

3.3 Contingent Valuation Method

[3] However, the method of reaching the hourly cost for each action is not reported in detail.

In order to measure WTP, the Contingent Valuation Method (CVM) is often employed in customer surveys. By means of questionnaire or telephone interview, the respondents are asked about the maximum amount they would be willing to pay to prevent the welfare loss occurring or to preserve the current quality level (Turner, 1993). Willingness to accept (WTA) refers to the amount of money which compensates the customers such that a welfare loss change does not occur. Drawing on considerable findings from the environmental research, WTA is significantly greater than WTP. As found by Bishop et al. (1979), experimental analysis produces disparate WTP and WTA measures. This gives rise to caution in using WTA valuations, which are perceived as less accurate predictors of actual buying and selling decisions. Hanemann (1991) points out that the theoretical presumption of approximate equality between WTP and WTA is misconceived.

3.3.1 Conjoint Analysis

Conjoint analysis (CA) is one of the techniques used in contingent valuation to address 'stated preference' by asking customers to make trade-offs among pre-specified choice sets with variation in prices and attributes. Compared with other contingent valuation methods (CVMs), which present the customer only one alternative at a price, conjoint analysis will provide more information with better quality (Louviere, 1988).

3.3.2 Hypothetical Bias

A major area for criticism is whether contingent value estimated in a hypothetical situation actually approximates the amount that would be paid if real money were involved. It is commonly agreed that the CVM leads to over-estimation due to general lack of consideration of budget constraints. Hypothetical bias appears both in public and private goods. Strategic bias might occur when respondents feel that their interests will best be served by giving a higher or lower value than their true WTP. In recent years, given concerns about the reliability of open-ended techniques, there is growing popularity in the use of discrete choice questionnaires. Hoehn et al. (1987) contended that the opportunity for strategic behaviour in discrete choice surveys is minimal.

In order to improve the reliability of the results, the National Oceanic and Atmospheric Administration (NOAA) panel suggested face-to-face interviews (Arrow et al., 1933). Regarding the nature of goods, the incentive for strategic behaviour may not exist for private goods according to

Kealy (1993). This viewpoint is echoed by List et al. (2001) who suggest that if respondents had purchase experience with regards to certain products, the error in valuing those products will be reduced. Other studies such as Loomis (1990) generally support the reliability of CVM instruments.

Contingent valuation is recommended as the best method of determining local preferences in a review study conducted for the South Australian Independent Industry Regulator (SAIIR, 2000). The uncertainty inherent in individual's economic valuation process can never be fully resolved. Although all surveys aim for accurate measurement, in many cases, the currently available technique is still preferable where there is no other alternative. In this study we make use of, interviews with customers who have experienced power interruptions in real world situations in the past.

3.4 Customer Survey on WTP

Sanghvi (1982) summarizes 35 studies that use different approaches based on product cost, material loss and equipment damaged, wages lost, lost leisure, WTP, and input-output production functions to estimate economic cost of electricity supply interruptions in industrial, commercial and residential sectors respectively. Woo (1992) states that the lack of historical data on WTP surveys has led to a compromised method of evaluating the value that customers place on service reliability by estimating the opportunity cost of supplied electricity. Thus, customer valuation of service reliability becomes synonymous with their outage costs. Among the different methods, the CV method is recommended due to its merit in data requirements, computational costs, the verifiability of results, and sensitivity to important causal factors such as outage attributes as well as customer demographics.

Table 4 summarises some studies of WTP in the electricity sector carried out in recent years. The outlined customer surveys share common features in terms of customers' valuation. For example, the WTPs relates positively to the duration of the outages and the values for unplanned outages are higher than those of planned outages. The longer the duration, the larger the total WTP. However, the WTP varies greatly among consumer categories, the time of occurrence, duration, frequency, and magnitude of outages.

Table 4: Customer Surveys of Willingness-to-Pay

Study (Year)	**Scope**	**Method /Data sample**	**Response %**	**WTP/WTA** (£, 2003/04 price)	**% of bill**
Beenstock (1990)	Israel	Contingent valuation Interview to estimate the aggregate cost of unsupplied electricity - Cost per kWh unsupplied	650 households Over 10% did not reply	**Domestic** **WTP** £2.31per Kwh **WTA** £1.87 per Kwh	NA
Hartman et al. (1991)	US	Contingent valuation Survey of WTP to avoid / WTA to accept one additional outage - unplanned outage - duration: 1hr, 4hrs, 12hrs - weighted average of winter and summer, morning and Evening WTP/WTA - 1GBP : US$1.4699	2,200 households in the PG&E service territory	**Domestic** **WTP** £0.02 per minute **WTA** £0.08 per minute	NA
Energy Australia c/o IPART* (1999) in Sayers et al. (2001)	NSW Australia	Conjoint analysis Survey to achieve one interruption per year. - Energy Australia - SAIDI: 74 minutes; SAIFI: 1.27 - 1GBP: US$1.7883 - Details of this survey not clearly stated in Sayers' paper.	1,000 business customers of DNO Energy Australia	**Business** **WTP** £123.02 or more in a fixed year charge (67% of small business would pay)	NA
MORI (1999)	UK	Focus group discussion Quantitative Questionnaire Survey of WTP for specific reliability Improvements. - WTP for improved service: payments after more than 4 power cuts per year - WTA: Compensation on more than average power cuts per year	503 tel. interview, 2,029 face-to-face interviews.	57% of customers do not want to pay anything **Business** **WTP** (34% of business customers are willing to pay) **Domestic** **WTA** £43.62 per year **Business** **WTA** £208.48 per year	1.5%
Carlsson et al. (2004)	Sweden	Contingent valuation Survey of WTP to avoid one outage of a certain duration starting at 6:00pm in an evening in January. - planned and unplanned outage - duration: 1hr, 4hrs, 8hrs, 24 hrs - weighted average of WTP - 1GBP: 14.2922SEK	1,678 returned questionnaire out of 3,000 respondents	**Weighted-avg** **WTP** £0.009 per minute (Planned) £0.012 per minute (Unplanned)	NA

Ofgem-Accent (2004)		Conjoint Analysis Survey of WTP to avoid one outage - 2,100 quota-controlled telephone business interviews and quota-controlled face-to-face domestic interviews - Value per minute reduction to avg cut - Value of 20 minute reduction to avg cut - Value of 40 minute reduction to avg cut - Weighted average of WTP	2,118 domestic interviews 1,965 business interviews	**Domestic** Weighted-avg **WTP** £1.09 (1 min) £21.80 (20 mins) £43.60 (40 mins) **Business** Weighted-avg **WTP** 1 min 20 mins 40 mins (Expressed in % only)	 0.3% 6.0% 12% 0.14% 2.88% 5.77%
* IPART: Independent Pricing and Regulatory Tribunal in NSW ; W: Winter; S: Summer; M: Morning; E: Evening; SAIDI: System Average Interruption Duration Index, SAIFI: System Average Interruption Frequency Index.					

3.5 Ofgem-Accent's Customer WTP Survey

In a customer survey on behalf of Ofgem, Accent conducted adopted a conjoint approach to measure customers' WTP to avoid service interruptions (OFGEM, 2004a). Respondents were asked for their preference for one type of service over the other. Those who indicated a preference were asked to state the maximum amount they would be willing to pay to receive this type of service. A total of 1,965 quota-controlled telephone business interviews and 2,118 quota-controlled face-to-face domestic interviews were conducted. A quota was set on type of location (urban/rural) to ensure adequate representation of all groups in the sample. In the domestic segment, although there were differences between urban and rural customers, both types of customers expressed a WTP of about £20 extra a year to avoid a power cut in their local areas and close to £22 a year to reduce the average duration of outages by 20 minutes per year (the average duration per customer in 2003/04 was 71 minutes per year) (OFGEM, 2004a). Business customers were prepared to pay 0.14% of their total bill for an average reduction of 20 minutes in outages. The survey reveals that the customers' average WTP expressed in £s per month change when expressed in % of their monthly bill.

Although Ofgem relies on the survey data of System Customer Outage Costs (SCOCs) to estimate the capitalized value of the target improvements of quality of service (OFGEM, 1999c), it shows an equivocal attitude towards the recent WTP survey. As found in the initial consultation of Ofgem's Price Control Review, customer WTP survey is perceived as a key input for revising the Guaranteed and Overall Standard Performance (GOSPs), outputs and incentives, and the exemptions mechanism (OFGEM, 2003a).

Initially, Ofgem agreed that the appropriate targets and incentive rates should be based on a series of criteria including consumers' WTP (OFGEM, 2003a). However, later Ofgem changed tack stating that the results were indicative and not definitive (OFGEM, 2003c). Meanwhile, a strong echo has been heard from the House of Commons (House of Commons, 2004) highlighting the need to focus on consumer welfare. Moreover, some DNOs feel that Ofgem did not organize the WTP surveys effectively or use the results appropriately (OFGEM, 2005b). Table 5 summarizes the responses and comments given by various organizations.

Table 5: Comments on 2003/04 Ofgem-Accent's WTP survey

Organization	Period	Summary of Responses and Comments
Ofgem	July, 2003	- Agrees targets and incentive rates should be based on criteria including consumers' WTP (OFGEM, 2003a).
Ofgem	September, 2003	- Sceptical about survey results because scale of the WTP is very high compared to other studies (OFGEM, 2003c).
Ofgem	November, 2004	- acknowledges that customers are willing to pay more but only up to a certain point. (OFGEM, 2004d). - states that in setting the amount of revenue exposure to QoS has considered the survey results.
House of Commons – Trade and Industry Committee	December, 2004	- Understands that Ofgem reluctant to base entire approach to new price control review on results of one survey. (House of Commons, 2004). - Considers Ofgem unwilling to accept that British consumers might place a significantly higher premium on improved network resilience than other consumers. - Does not believe Ofgem know better than consumers what they want.
DNOs	July, 2005	- Some feel that Ofgem neither organize the willingness-to-pay surveys effectively nor uses the results appropriately (OFGEM, 2005b).

3.6. Other DEA Studies with Outage Cost/WTP

A recent study applies DEA-Malmquist productivity indices to Denmark, Finland, Norway, Sweden and the Netherlands using total operating (TOM) cost as input (labor cost, other operating costs and maintenance costs have been aggregated), the replacement value of assets, and energy losses (Edvardsen et al., 2003). Energy delivered, number of customers, and total lines are used as outputs. Norwegian prices are chosen as weights for all countries.

Lassila et al. (2003), on the other hand, attempts to define the price of outages in the distribution networks in Finland in terms of additional profits earned resulting from the decrease in interruption time. The decrease in interruption time will result in improvement in efficiency score of firms, which increases the return on capital. Thus, the prices of outages can be derived from the efficiency sensitiveness where efficiency score is served as a function of the interruption time of customers. According to this study, the outage cost can only demonstrate part of the cost picture, illustrating the price elasticity of the way in which a change in the firm's operational cost resulting from improvement in DEA score will affect the duration of interruption. The implication is that the more the firm invests in operational cost with an aim to uplift the reliability standard, the lower the frequency of interruptions. This logic, however, neglects the possibility that quality of service level chosen by the firms will not necessarily match the social optimum.

4. Methodology

4.1 Data Envelopment Analysis (DEA)

DEA uses the linear programming technique to construct a nonparametric production frontier. It makes minimal assumptions about the form of the production function (Fare et al., 1978). Drawing upon the work of Debreu (1951), Farrell (1957) first developed a simple measure of firm efficiency which allows multiple inputs. Resting on the concept of production function (y = f(x_1, x_2)), which describes the maximum output (e.g. y) produced using particular set of inputs (e.g. x_1, x_2), an efficiency frontier can be constructed using input-output data on firms in a relative fashion. This frontier becomes a benchmark made up of the best performing firms and envelops the remainder in the sample. Each firm receives a relative efficiency score between zero and one derived by the ratio of the sum of weighted outputs to the sum of corresponding weighted inputs.

DEA provides a set of scalar measures of efficiency, namely input-oriented measures and output-oriented measures. An input-oriented model assuming constant returns to scale (CRS) was first introduced and followed by the latter model of variable returns to scale (VRS) proposed by Banker, Charnes and Cooper (1984). The CRS frontier allows smaller firms to be benchmarked against bigger firms and vice versa. On the contrary, the VRS frontier is free from scale-induced biases and allows firms of a similar operational size to be benchmarked against each other. Historically in the electricity sector, the scale of a firm's operation is beyond its control, so the regulator attempts to eliminate the effects of scale efficiency from the productivity measures especially when setting the X-factors (Coelli, 2003). Given that electricity distribution utilities are bound by legal obligations to serve all customers in their territories, we use an input-oriented DEA model, assuming a fixed level of output and strong disposability in both inputs and outputs. The disposability assumption implies that an increase in inputs does not result in a decrease in outputs, and that any reduction in outputs can still be produced with the same amount of inputs.

4.2 Technical and Allocative Efficiency

According to Farrell (1957), a firm's productive efficiency can be measured in terms of technical efficiency and allocative efficiency. Technical efficiency refers to the ability of a firm to obtain maximal output from a given set of inputs, while allocative efficiency refers to the ability of a firm to use the inputs in optimal proportions, given their respective prices (Coelli et al., 2003). The combination of these two efficiencies measures the total economic efficiency (i.e. cost efficiency).

The computation of the efficiency score for *i*th firm in a sample of *N* firms in CRS models follows the model below. θ is a scalar and λ is a *I* x 1 vector of constants. *X* and *Y* denotes *N* x I input and *M* x I output matrices respectively assuming *K* observed inputs and *M* observed outputs are used by the firms.

Cost minimization - Technical efficiency

$$
\begin{aligned}
&Min_{\theta,\lambda}\theta \\
&subject\ \ to \\
\\
&-y_i + Y\lambda \geq 0, \\
&\theta x_i - X\lambda \geq 0, \\
&\lambda \geq 0
\end{aligned}
$$

If the value of θ - i.e. the efficiency score for the *i*th firm is equal to 1, it means that the current input levels cannot be reduced proportionally. This indicates a point on the frontier and hence a technically efficient firm (Farrell, 1957). If min θ is smaller than 1, the firm is dominated by the frontier. The equation is solved *N* times and a value of θ is obtained for each time.

To obtain allocative efficiency (AE), two sets of linear programs are required – one to measure technical efficiency (TE) and the other to measure economic efficiency (EE). The allocative efficiency is calculated residually by AE = EE / TE (see Coelli et al., 2005).

Cost minimization – Allocative efficiency

$$
\begin{aligned}
& Min_{\lambda, xi*} w_i' x_i^* \\
& \\
& subject \;\; to \\
& -y_i + Y\lambda \geq 0 \\
& x_i^* - X\lambda \geq 0 \\
& \lambda \geq 0
\end{aligned}
$$

w_i is a vector of input prices for the *i*-th firm and x_i^* (calculated by the linear program) is the cost-minimising vector of input quantities for the i-th firm, given the input prices w_i and output levels y_i (Coelli, 2005). The total economic efficiency (EE) of the i-th firm can then be calculated as

EE = $w_i' x_i^* \, / \, w_i' x_i$.

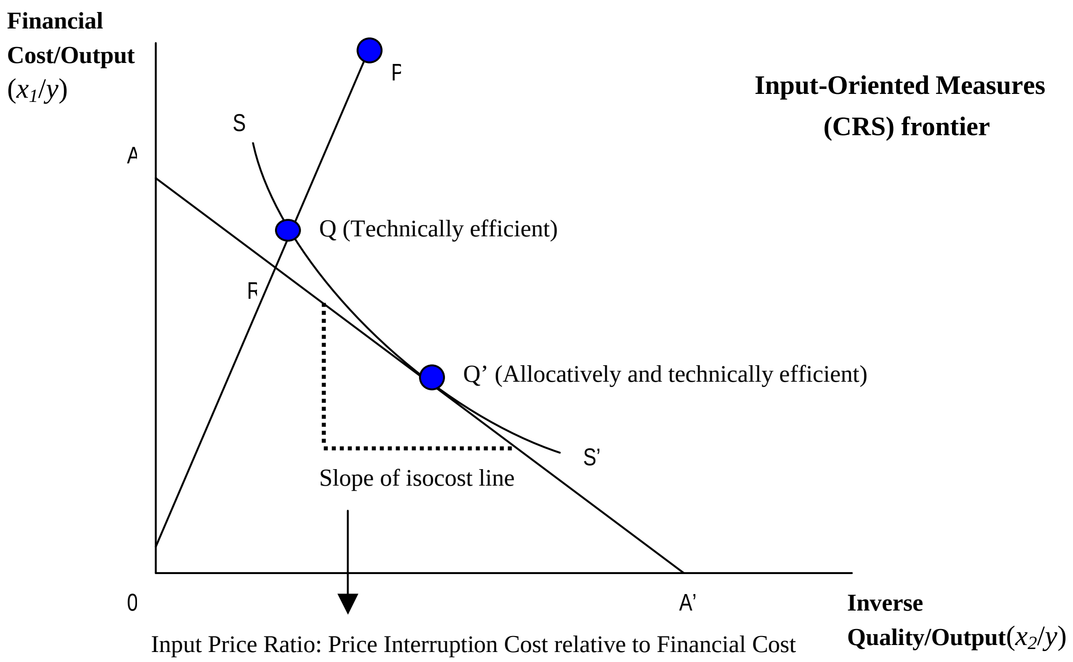
Under the assumption of CRS, an isoquant SS' is used to depict all combinations of input (x_1 ,x_2) that could produce a particular quantity of output (*y*) (Figure 2). Two of the inputs used in our study are the financial cost (x_1/y) and inverse quality (x_2/y) of DNOs. Financial cost refers to the total financial expenditure (Totex). Inverse quality represents an undesired quality dimension expressed as average CML (weighted).

When the unit isoquant of fully efficient firms, represented by SS', is known, the technical efficiency can be calculated. Graphically, technical efficiency shows how far a given DNO is from the frontier. A given firm Q is technically efficient since it lies on the isoquant. On the contrary, firm P is technically inefficient since it is located on the interior of the production isoquant. Any shortfall from the estimated frontier is interpreted as inefficiency and the distance QP between the inefficient firm and frontier can be viewed as a measure of potential efficiency that an inefficient firm P needs to catch up with.

The isocost line AA’ in Figure 2 represents the budget constraint for the firms expressed as a financial cost against interruption cost. After adding the isocost line whose slope reflects relative price of interruptions, the point Q is no longer allocatively efficient. Allocative efficiency shows how far the firm is from the (given the relative input prices) frontier. The new point Q’ where the isoquant and the isocost lines are tangents becomes a firm which is both technically and allocatively efficient. Allocative efficiency reflects the ability of DNOs to exploit differences in input prices - i.e. that is choosing a point in the desired isoquant such that it that coincides with the lowest possible isocost line.

Figure 2: Technical and allocative efficiencies

Source: Adapted from Coelli et al. (2005)



The technical efficiency (TE) and the allocative efficiency (AE) of a firm can be expressed by the ratio shown in formula 1 and 2 respectively. Formula 3 shows the total economic efficiency (EE) which is the product of formula 1 and 2.

Total economic efficiency

TE = OQ / OP [1]

AE = OR / OQ [2]

EE (TE*AE) = OR / OP [3]

5. Data and Model Specifications

5.1 Choice of Variables

There is no consensus on the input and output variables used in DEA measurement for electricity distribution. Jamasb and Pollitt (2001) report number of employees, operating costs, transformer capacity and network length as the most widely used variables in electricity benchmarking studies. The most common outputs are units of energy delivered and number of customers. In our study, physical variables such as total number of customers (CUST), units of energy delivered (ENGY) and total network length (NETL) are considered as outputs given that the pricing of distribution varies according to both of these dimensions. There is a lesser consensus on using network length as input or output. However, the use of network length assumes that it measures the difficulty of topology by holding customer numbers and units of energy delivered constant.

In our analysis, we use customer minutes lost (CML) as quality attribute of the firm's output in which a reduction is regarded as desirable. Following Yaisawarng and Klein (1994), we include the undesirable output attribute as ordinary input. In an input-oriented DEA model, this can be interpreted as that a firm can reduce the undesirable output attribute and cost (as an ordinary) input while maintaining a given level of ordinary output. Energy Losses (ENGY LOSS) is either considered as input or output. In this study, it should be viewed as an input to be minimized as other inputs. Other than physical measures of inputs, monetary inputs such as Opex, and Totex are included in our model. Totex is the sum of Opex, network investments and non-operational capital expenditure.

5.2 Dataset

We compare the performance of 14 DNOs in the UK for the 1990/91 to 2003/04 period. Figures 3 to 8 show the overall trends of the variables used in the DEA models averaged across DNOs. The monetary and physical data for the input and output variables were obtained from Ofgem. Both Opex and Capex display a downward trend (Figure3). The physical output in terms of units of energy delivered (Figure 4), customer number (Figure 5) and total network length (Figure 6) are steadily increasing.[4] The data on quality is mainly based on the information from Ofgem's annual Electricity Distribution Quality of Service Report. The weighted duration (CML) of customer interruption

[4] Network length exhibits fluctuations over years, according to Ofgem it is due to the problem of reporting accuracy.

exhibit a mild downward trend (Figure 7). The weighted distribution loss figure continues to rise in the second price control period (Figure 8). A downward trend in the distribution losses is evident at the beginning of 2001.

5.3 Valuation of Cost of Quality

The available WTPs for 2003/04 cover both domestic and business customers in 14 DNO regions expressed in terms of the percentage of the annual bill. The data was obtained from Ofgem-Accent's WTP survey in 2004 (OFGEM, 2004a). In order to calculate the WTP (in GBP), it is necessary to estimate domestic and business bill amounts between 1990/91 and 2003/04. However, the relevant data for 14 regional bills is unavailable. The total annual national bill amounted to around 16 billion in 2003/04 (OFGEM, 2005c). By means of an alternative method, the annual bill amount for each DNO were computed by multiplying its units of energy delivered by its average electricity price. Appendix II summarizes the sources of data and the method used in estimating the bill and WTP.

In the UK, there had been no WTP surveys conducted for power interruption avoidance before 2004. As a result, we applied the same WTP as percentage of bill obtained in Ofgem-Accent's survey (2003/04) to the entire period of our study (1990/91-2002/03), with an assumption that the customer's degree of WTP for avoiding power interruption remains constant in relation to their bill during that period in 14 DNO areas.

5.3.1 Total WTP

The final aggregate WTP of the DNOs for a one minute reduction in average annual interruption is calculated by adding the total domestic and business WTPs (Equation 4).

Final Aggregate WTP

$$FWTP'^{D\&N}_{it} = TWTP'^{N}_{it} + TWTP'^{D}_{it} \qquad [4]$$

$FWTP'^{D\&N}_{it}$: Final aggregate WTP in £ by 14 DNOs 1990/1-2003/4

$TWTP'^{N}_{it}$: Total Business WTP in £ by 14 DNOs 1990/1-2003/4

$TWTP'^{D}_{it}$: Total Domestic WTP in £ by 14 DNOs 1990/1-2003/4

i = 1, 2, 3, … 14 (DNO); t = 1990/91 -2003/04; D: Domestic; N: Non-Domestic (Business)

Figure 3: Monetary variables (2003/04 £ mill.)

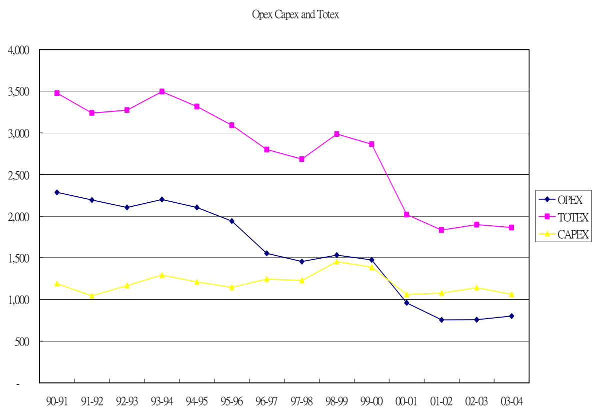


Figure 4: Total Energy Delivered (Gwh)

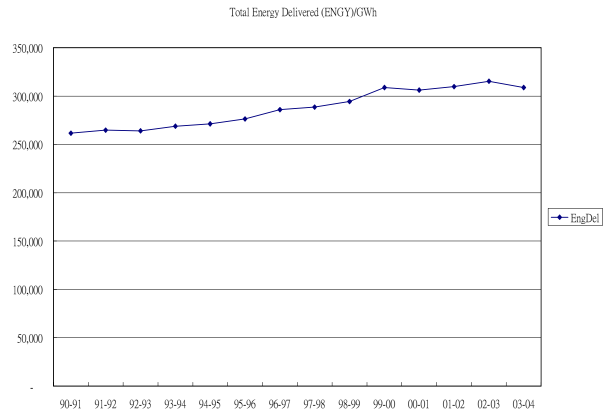


Figure 5: Number of Customer (Thousand)

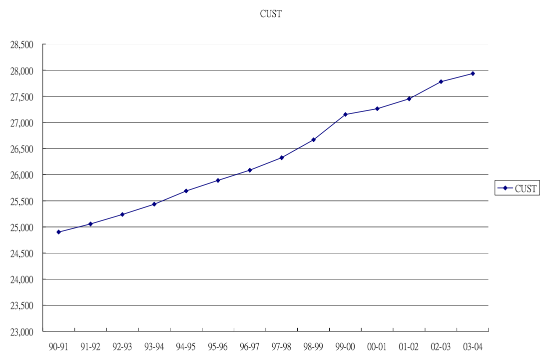


Figure 6: Network Length (Km)

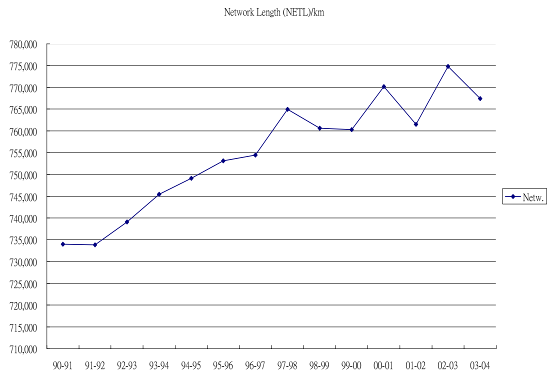


Figure 7: Avg. Customer Minutes Lost (weighted)

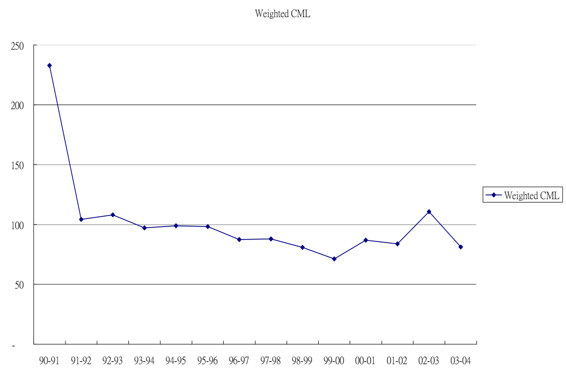
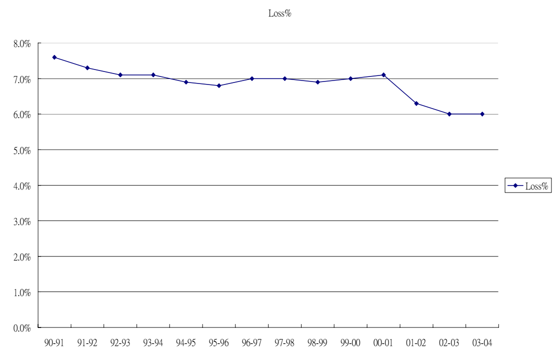


Figure 8: Avg. Distribution Losses (weighted) (%)



5.3.2 Domestic Electricity Price and Units of Energy Delivered

Average domestic electricity price and units of energy delivered (domestic) are used to estimate the domestic bill amounts for DNOs (Equation 6). The calculation of bill amount is detailed in Sub-section 5.3.4 below. Since no single source of data can provide complete years of average domestic unit prices, figures for 1990/91-1993/94 are based on the national unit price given in Electricity Association (2002). Prices between 1994/95 and 2003/04 are drawn based on the unit prices of electricity in selected cities (inclusive of value added tax) and as reported in the Department of Trade and Industry's quarterly price report which shows the regional price difference (DTI, 2002).

The national price figures for 1990/91-1993/94 have been adjusted to reflect regional variance among DNOs based on the weighting derived from the DTI's annual domestic electricity bills for selected cities (DTI, 2002). Two sets of domestic pricing have been harmonized in order to show a consistent trend. The units of energy delivered (domestic) are obtained from Ofgem's various documents.

5.3.3 Domestic WTP

As shown in Table 6, an aggregate domestic WTP (% of bill) for 2003/04 is derived from the weighted average between rural and urban WTP given in Ofgem-Accent's survey (OFGEM, 2004a). The domestic bill for 2003/04 is also based on the result of the survey. The estimated amount given by domestic customers during their interviews is somewhat higher than the actual bill. According to Ofgem, this could be attributed to the timing of the field work, immediately following the coldest quarter of the year.

Total domestic WTP is the product of the weighted average WTP and number of customers (domestic) by the DNO. Table 6 shows the total domestic WTP per minute by 14 DNOs. The total domestic WTP in 2003/04 is about £22.8 million based on Ofgem-Accent's survey. For the remaining years spanning from 1990/91-2002/03, the domestic WTP (Equation 5) can be computed from the annual domestic electricity bill (Equation 6) and weighted average WTP (% of bill) for the year 2003/04.

Domestic WTP

$$TWTP'^{D}_{it} = TB^{D}_{it} * WTP^{D}_{it'} \qquad [5]$$

1. $TWTP'^{D}_{it}$: *Total Domestic WTP in £ by 14 DNOs 1990/1-2003/4*

2. TB^{D}_{it} : *Total Annual Domestic Bill amount in £ by 14 DNOs 1990/91-2003/04*

3. $WTP^{D}_{it'}$: *Domestic WTP in terms of % of bill by 14 DNOs 2003/04*

i = 1, 2, 3,…14 (DNO); t = 1990/91 -2003/04; t' = 2003/04;

D: Domestic; N: Non-Domestic (Business)

Table 6: Domestic WTP values by DNO in 2003/4

DNO	**OFGEM-Accent Survey Est. annual Bill (£)**	**Rural Breakdown (%)**	**Urban Breakdown (%)**	**Weighted Avg WTP per minute (% of bill)**	**Weighted Avg WTP Per minute (£)**	**No of Customer (000)**	**Total Domestic WTP per minute (£)**
2003-2004	(1)	(2)	(3)	(4)	(1) * (4)=(5)	(6)	(5) * (6)=(7)
EDFE EPN	326.58	29%	71%	0.23%	0.75	3083	230,5678
CN East	336.81	48%	52%	0.25%	0.84	2253	1,881,906
EDFE LPN	506.18	0	100%	0.20%	1.01	1917	1,940,694
SP Manweb	383.73	31%	69%	0.23%	0.89	1334	1,182,479
CN West	408.39	52%	48%	0.25%	1.03	2165	2,228,094
CE NEDL	346.22	28%	72%	0.23%	0.79	1399	1,104,201
UU	313.08	32%	68%	0.23%	0.73	2132	1,548,569
EDFE SPN	363.3	24%	76%	0.22%	0.81	1916	1,559,225
SSE Southern	326.92	44%	56%	0.24%	0.80	2527	2,015,601
WPD S Wales	398.9	29%	71%	0.23%	0.91	1075	981,992
WPD S West	373.41	62%	38%	0.26%	0.98	1466	1,434,238
CE YEDL	394.1	31%	69%	0.23%	0.91	2060	1,875,713
SSE Hydro	569.55	65%	35%	0.27%	1.51	615	928,224
SP Distribution	396.82	48%	52%	0.25%	0.98	1818	1,789,119
Total:							**22,775,733**
Source: OFGEM report – Consumer Expectations of DNOs and WTP for Improvements in Service (Report June 2004) (prepared by Accent Marketing & Research, London)							

5.3.4. Domestic Bill Amount for 1990/91 to 2002/03

The annual domestic bill amount can be estimated by multiplying the units of energy delivered (domestic) by average domestic electricity price (Equation 6). However, the domestic bill amount and WTP for 2003/04 are derived following the same formula. These figures are then compared to the actual bill amounts and WTPs from Ofgem-Accent's Survey (2003/04) as shown in Table 6. By harmonizing two sets of data for 2003/04, we are able to devise a formula to adjust our billing estimations across the whole period.

Domestic Bill Amount

$$TB^{D}{}_{it} = E^{D}{}_{it} * P'^{D}{}_{it} \qquad \textbf{[6]}$$

1. $TB^{D}{}_{it}$: *Bill amount in £ by 14 DNOs 1990/91-2003/04*

2. $E^{D}{}_{it}$: *Energy Delivered (Gwh) by 14 DNOs 1990/91-2003/04*

3. $P'^{D}{}_{it}$: *Average Electricity Price in £ by 14 DNOs 1990/91-2003/04*

i = 1, 2, 3,…14 (DNO); t = 1990/91 -2003/04; D: Domestic; N: Non-Domestic (Business)

5.3.5 Non-domestic (Business) Electricity Price and Units of Energy Delivered

Average non-domestic electricity price and units of energy delivered (commercial and industrial) are used to estimate the total business bill amounts for DNOs (Equation 6). Non-domestic electricity prices are a combination of commercial and industrial prices. The average price (weighted) of electricity purchased by small, medium, moderately large and very large consumers, exclusive of VAT, represents the national industrial price (DTI, 2006).[5]

The national commercial price is recorded in April of the current year and is available for the period up to 2001/02 inclusive (Electricity Association, 2002). Prices for the remaining years are projected based on the price trend in line with the industrial price (DTI, 2006). Since national industrial and commercial prices are used, adjustment based on the regional weighting factor derived from the illustrative bill for medium size businesses has been made to reflect any pricing variance among

[5] To retain consistency with the fiscal period of price control reviews, the average national industrial price is computed by taking an average of the total sum of price in Quarter 2, 3, 4 of the previous year and Quarter 1 of the current year. The national industrial price is available from 1990/91 to 2003/04 from DTI documents.

DNOs (CRI, 1998). The illustrative bill for the CRI is recorded up to 1998/99 and serves as the basis for adjusting the above prices of subsequent years. The units of energy delivered by industrial and commercial sectors are derived from the share of the two user groups. The data is available for the period from 1990/91 to 2003/04. Appendix II summarizes the sources of data and formulas used in estimating the business bill and WTP.

5.3.5 Business (Non-Domestic) WTP

Business WTP percentage was collected in Ofgem-Accent's survey in 2004 by interviewing three bands of business customers large (over 1MW/£159K+), medium (over 100KW/£15K) and small (less than 100KW/£15K) (OFGEM, 2004a). The DNO areas were combined into four areas for regional analysis in the survey which are shown as follows.[6] EDF Energy Networks (LPN) was analysed separately as it had a different design.

- Region 1: WPD South West, WPD South Wales, SP Manweb
- Region 2: EDF Energy Networks (EPN), EDF Energy Networks (SPN), Southern
- Region 3: Central Networks (West), Central Networks (East), YEDL, NEDL, UU
- Region 4: Scottish Power, Scottish Hydro.

As shown in Table 7, total business WTP for 2003/04 as derived from the product of our estimated business bill amount and business WTP (% of bill) reported in Ofgem-Accent's survey (OFGEM, 2004a) (Equation 7). The table also shows that the combined result of WTP percentage and the total business WTP amounts to about £17.5 million.

Business (Non-domestic) WTP

$$TWTP'^{N}_{it} = TB^{N}_{it} * WTP^{N}_{it'} \qquad \textbf{[7]}$$

1. $TWTP'^{N}_{it}$: *Total Business WTP in £ by 14 DNOs 1990/1-2003/4*

2. TB^{N}_{it} : *Total annual business (non-domestic) bill in £ by 14 DNOs 1990/91-2003/04*

3. $WTP^{N}_{it'}$: *Business WTP in terms of % of bill by 14 DNOs 2003/04*

i = 1, 2, 3,…14 (DNO); t=1990/91-2003/04; t'=2003/04; D: Domestic; N: Non-Domestic (Business)

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[6] The figures for business WTP percentage by 14 DNOs are reported in the appendix of Ofgem-Accent's survey. DNOs indicating zero as WTP have been assigned with an average WTP (% of bill) of the regions they belong to.

Table 7: Business WTP values in 2003/04

DNO	Region No.	Est. Annual Business Bill (£)	2003/04 Business WTP per minute (%)	Total Business WTP amount Per minute (£)
2003/04		(1)	(2)	(1) * (2) = (3)
EDFE EPN	2	903,104,207	0.10%	903,104
CN East	3	805,797,396	0.18%	1,450,435
EDFE LPN	-	1,408,862,609	0.12%	1,690,635
SP Manweb	1	462,115,139	0.24%	1,109,076
CN West	3	806,925,027	0.13%	1,049,003
CE NEDL	3	532,619,662	0.18%	958,715
UU	3	745,614,656	0.22%	1,621,712
EDFE SPN	2	612,890,962	0.15%	888,692
SSE Southern	2	535,323,555	0.19%	1,017,115
WPD S Wales	1	396,435,884	0.27%	1,050,555
WPD S West	1	462,253,635	0.29%	1,340,536
CE YEDL	3	726,708,274	0.38%	2,761,491
SSE Hydro	4	252,070,979	0.16%	403,314
SP Distribution	4	778,055,636	0.16%	1,244,889
Total				**17,489,272**

5.3.6 Business (Non-Domestic) bill

The total business bill amount between 1990/91 and 2003/04 of each DNO is arrived at by multiplying units of energy delivered (industrial and commercial) by the average industrial and commercial electricity price respectively for that year (Equation 8).

Business (Non-domestic) Bill Amount

$$TB^{N}{}_{it} = E^{I}{}_{it} * P'^{I}{}_{it} + E^{C}{}_{it} * P'^{C}{}_{it} \qquad [8]$$

1. $TB^{N}{}_{it}$ *:Total Annual Business (non-domestic) Bill in £ by 14 DNOs 1990/91-2003/04*

2. $E^{I}{}_{it}$ *: Energy delivered (Industrial) (Gwh) by 14 DNOs 1990/91-2003/04*

3. $E^{C}{}_{it}$ *: Energy delivered (Commercial) (Gwh) by 14 DNOs 1990/91-2003/04*

4. $P'^{I}{}_{it}$ *: Average industrial electricity price in £ £by 14 DNOs 1990/91-2003/04*

5. $P'^{C}{}_{it}$ *: Average commercial electricity price in £by 14 DNOs 1990/91-2003/04*

i = 1, 2, 3,…14 (DNO); t=1990/91-2003/04; D: Domestic; N: Non-Domestic (Business); I: Industrial; C: Commercial

5.3.7 Energy Losses in Distribution

Distribution loss percentages by DNO area 1990/91 to 1997/98 are available from Ofgem documents (OFGEM, 1998). Information in distribution loss percentages between 1998/99 and 2003/04 can be found on Ofgem's website (OFGEM, 2006). Distribution output can be estimated from Equation 9. The energy loss (in GWh) for each DNO is the product of distribution output and losses in percentage (Equation 10).

Distribution Losses

$$DO_{it} = TED_{it} / (1 - Loss)_{it} \qquad [9]$$

$$DL_{it} = DO_{it} * Loss_{it} \qquad [10]$$

1. TED_{it} : *Total Energy Delivered after loss (GWh)*
2. DL_{it} : *Distribution Losses (GWh)*
3. DO_{it} : *Distribution Output before loss (Gwh)*
4. $Loss_{it}$: *Loss percentage (%)*

i = 1, 2, 3,…14 (DNO); t =1990/91-2003/04; D: Domestic; N: Non-Domestic (Business)

5.3.8 Input Prices

We also incorporate input prices to measure cost efficiency. The unit price of CML is the value of WTP (domestic and business) for avoidance of a one minute power interruption. Energy loss (ENGY LOSS) is measured in GWh and priced by the average industrial electricity price. The price of Opex, Capex and Totex is by convention set to 1.

5.4 Model Specifications

Extending a previous study carried out by Giannakis et al. (2005) which measured only the technical efficiency, two additional models (Model 4, 5) will be introduced in this research and the allocative efficiency between production cost and quality cost will be measured. Table 8 summarizes the cost inputs, price inputs, outputs, and quality attributes used in the models.

Table 8: Model specifications – input/output

Model	1	2	3	4	5
Inputs					
OPEX	√			√	
TOTEX		√	√		√
CML			√	√	√
ENGY LOSS				√	√
Input price					
1 (TOTEX)			√	√	√
WTP (CML)			√	√	√
ENGY PRICE(LOSS)				√	√
Output					
CUST	√	√	√	√	√
ENGY DELV	√	√	√	√	√
NETL	√	√	√	√	√
Efficiency					
	TE	TE	TE,AE	TE,AE	TE,AE

OPEX: Operating expenditure	*CAPEX: Capital expenditure*	*TOTEX: Total expenditure*
CML : Duration of interruptions	*ENGY LOSS: Energy physical loss*	*WTP: Willingness-to-pay*
ENGY PRICE: Energy Price	*CUST: Total number of customers*	*NETL: Total network length*
ENGY DELV: Energy delivered	*TE: Technical efficiency*	*AE: Allocative efficiency*

- Model 1 (Model Opex) resembles Ofgem's COLS model and is used as the base model. It treats Opex as an input while the output containing number of customers, energy delivered and network length is similar to the composite size variable of the Ofgem.

- Model 2 (Model Totex) aims at eliminating effects due to potential tradeoffs between Capex and Opex. Totex is defined as the sum of operational expenditures, network investments and non-operational capital expenditures.

- Model 3 (Model Totex-CML) incorporates the quality dimensions by including Customer Minutes Lost (CML). Based on the findings of Giannakis et al. (2005), this cost-quality model is preferable to a cost-only model. However, due to the lack of input price factor, this model does not measure whether technical efficiency is achieved at the expense of allocative efficiency.

- Model 4 (Opex-CML-Loss) is similar to that of Model 5, while Opex is used instead of Totex. The aim is to compare the difference between these two models if the regulator opted to benchmark Opex. Energy losses are treated separately with Capex and Opex as in the case of benchmarking measures.

- Model 5 (Totex-CML-Loss) represents a more holistic approach, embodying quality dimensions such as customer minutes lost and energy losses. This Cost-Quality-Loss model allows us to discern the firms' overall performance in quality, linking two losses as inputs based on the notion that DNOs should minimize the duration of interruptions and losses.

6. Results

This section reviews the main findings of this study. Table 9 summarizes the average DNO efficiency scores of five models using CRS technology structures.[7] CRS technology assumes that all decision-making units are operating at an optimal scale.

Table 9: Average DNO efficiency scores (1990/91 – 2003/04)

DNO	Model 1 TE	Model 2 TE	Model 3 TE	Model 4 TE	Model 5 TE	Model 3 AE	Model 4 AE	Model 5 AE	Model 3 OE	Model 4 OE	Model 5 OE
EDFE EPN	0.88	0.96	0.99	0.99	1	0.93	0.91	0.95	0.92	0.90	0.95
CN East	0.68	0.80	0.84	0.95	0.98	0.84	0.77	0.78	0.71	0.73	0.76
EDFE LPN	0.69	0.78	0.98	1	1	0.97	0.99	0.98	0.96	0.98	0.97
SP Manweb	0.74	0.80	0.92	0.93	0.93	0.90	0.9	0.90	0.83	0.84	0.84
CN West	0.72	0.83	0.82	0.99	1	0.69	0.6	0.64	0.56	0.60	0.64
CE NEDL	0.64	0.79	0.85	0.92	0.93	0.85	0.8	0.83	0.72	0.73	0.77
UU	0.72	0.75	0.89	0.99	0.99	0.95	0.91	0.90	0.85	0.91	0.89
EDFE SPN	0.74	0.86	0.89	0.91	0.93	0.89	0.85	0.90	0.80	0.78	0.84
SSE Southern	0.89	0.89	0.96	0.94	0.97	0.90	0.92	0.91	0.86	0.87	0.88
WPD S Wales	0.56	0.63	0.68	0.81	0.81	0.73	0.64	0.67	0.50	0.52	0.55
WPD S West	0.72	0.79	0.89	0.93	0.93	0.88	0.87	0.88	0.78	0.80	0.82
CE YEDL	0.78	0.91	0.99	1	1	0.95	0.94	0.95	0.94	0.94	0.95
SSE Hydro	0.91	0.97	0.95	1	1	0.89	0.91	0.92	0.85	0.91	0.92
SP Distribution	0.83	0.88	0.95	0.93	0.95	0.90	0.88	0.89	0.85	0.82	0.84
Sector Average	**0.75**	**0.83**	**0.90**	**0.95**	**0.96**	**0.88**	**0.85**	**0.86**	**0.79**	**0.81**	**0.83**

6.1 Model 1 – OPEX

We first consider the base Model Opex (Model 1). The results in Table 10 indicate that DNOs are, on average, technically inefficient by about 25%. They also imply that output level can be maintained while reducing operating expenditure by about 25% over the period. The Model Opex identifies Scottish Hydro, Southern and Eastern, as the most efficient DNOs consistent with the

[7] The DEA analysis was carried out using the software Onfront Version 2.0 (EMQ).

result reported in Giannakis et al. (2005) spanning a shorter period 1991/92–1998/99. Furthermore, Northern, Norweb, SWEB and London have improved their efficiency rankings significantly over the years.

Table 10: Model 1 - Average technical efficiency scores

Model 1 OPEX	1990/91-1994/95 TE	1995/96-1999/00 TE	2000/01-2003/04 TE	M1 1990/91-2003/04 TE
EDFE EPN	0.93	0.81	0.90	0.88
CN East	0.91	0.56	0.58	0.68
EDFE LPN	0.69	0.63	0.75	0.69
SP Manweb	0.89	0.74	0.60	0.74
CN West	0.85	0.71	0.60	0.72
CE NEDL	0.77	0.52	0.63	0.64
UU	0.78	0.54	0.86	0.72
EDFE SPN	0.79	0.82	0.62	0.74
SSE Southern	0.82	1.00	0.84	0.89
WPD S Wales	0.61	0.53	0.53	0.56
WPD S West	0.62	0.76	0.79	0.72
CE YEDL	0.88	0.75	0.70	0.78
SSE Hydro	1.00	0.98	0.76	0.91
SP Distribution	1.00	0.73	0.76	0.83
Sector Average	**0.82**	**0.72**	**0.71**	**0.75**

Table 10 compares the technical scores of Model 1 separately over three price control reviews. The degree of divergence between firms seems to be widening over time as indicated by the decrease in sector-wide scores. A consistent improvement in technical efficiency is expected following the painstaking effort made to reduce Opex year by year. However, half of the firms show declining efficiency scores across three price control periods. This may be explained by the influence of different incidents in relation to the allocation of operational cost with different firms; the first review period is marked by storms; the second period facing loss of vertical economies due to separation of supply business from distribution; and in the third price control the performance of DNOs stabilizes as mergers and acquisitions continue.

6.2 Model 2 – Totex

Model Totex in Table 11 shows a more consistent trend in efficiency scores over the three review periods than Model Opex. There is an overall improvement in the DNOs' efficiency score and three firms score greater than 0.90. The performance gap in this model is found to be smaller than that of the Opex-based benchmarking. The implication, therefore, is that the base Model Opex can penalize firms that are efficient in Capex. Moreover, in comparison, some frontier firms in Opex model are relatively distant from other firms, bringing down the overall score.

Table 11: Model 2 - Average technical efficiency scores

Model 2 TOTEX	**1990/91-1994/95 TE**	**1995/96-1999/00 TE**	**2000/01-2003/04 TE**	**M2 1990/91-2003/04 TE**
EDFE EPN	0.99	0.91	0.99	0.96
CN East	0.83	0.75	0.83	0.80
EDFE LPN	0.70	0.71	0.93	0.78
SP Manweb	0.85	0.87	0.69	0.80
CN West	0.84	0.88	0.77	0.83
CE NEDL	0.78	0.80	0.79	0.79
UU	0.79	0.65	0.80	0.75
EDFE SPN	0.80	1.00	0.79	0.86
SSE Southern	0.78	0.89	0.99	0.89
WPD S Wales	0.59	0.60	0.69	0.63
WPD S West	0.65	0.90	0.83	0.79
CE YEDL	0.96	0.82	0.95	0.91
SSE Hydro	1.00	0.92	0.99	0.97
SP Distribution	0.94	0.90	0.81	0.88
Sector Average	**0.82**	**0.83**	**0.84**	**0.83**

6.3. Model 3 – Totex-CML

The mean efficiency in the Models 3, 4 and 5 increases with the number of input variables and thus dimensions to the model. Adding or deleting variables as well as an increase or decrease in sample size can change the shape of the production frontier, and thus all efficiency scores computed, relative to the frontier. Model Totex-CML allows the measurement of the allocative efficiency. Table 12 shows that, over the whole period, the allocative inefficiency accounts for about 3% to 31% of the total economic loss while technical inefficiency varies between 1% and 32%, which indicates a significant gap in performance among DNOs.

Both efficiency scores of the firms have increased during the first and second price controls and exhibited a slight decline during the third review period. Steady decline of both Opex and Capex is a possible reason for this improvement. For technical efficiency, a number of DNOs ranked high in the cost-only model but low in the quality-model, similar to the findings of Giannakis et al. (2005). This implies a possible trade-off between expenditures and quality. The reverse scenario is evident for other firms. London, for example, ranks relatively low (No. 10) in Model Totex but high (No. 3) in

Model Totex-CML. Some DNOs display similar ranking patterns in both cost-oriented and quality-oriented model. Some well-performing firms in allocative efficiency ranked low in technical efficiency. The overall average economic efficiency score is 0.79, which implies that current output level can be maintained while reducing the overall cost by about 21%.

Table 12: Model 3 -Average economic efficiency scores

Model 3 TOTEX- CML	**1990/91-1994/95 TE**	**1995/96-1999/00 TE**	**2000/01-2003/04 TE**	**1990/91-2003/04 TE**	**1990/91-94/95 AE**	**1995/96-99/00 AE**	**2000/01-03/04 AE**	**1990/91-2003/04 AE**	**M3 1990/91-2003/04 OE**
EDFE EPN	0.99	1.00	0.99	0.99	0.98	0.96	0.85	0.93	0.92
CN East	0.86	0.83	0.84	0.84	0.74	0.96	0.82	0.84	0.71
EDFE LPN	0.95	1.00	1.00	0.98	0.95	0.97	1.00	0.97	0.96
SP Manweb	0.92	0.97	0.88	0.92	0.78	0.97	0.96	0.90	0.83
CN West	0.79	0.89	0.77	0.82	0.66	0.74	0.67	0.69	0.56
CE NEDL	0.87	0.85	0.83	0.85	0.75	0.92	0.89	0.85	0.72
UU	0.91	0.84	0.93	0.89	0.95	0.92	0.98	0.95	0.85
EDFE SPN	0.87	1.00	0.81	0.89	0.85	0.92	0.91	0.89	0.80
SSE Southern	0.89	0.99	0.99	0.96	0.89	0.99	0.83	0.90	0.86
WPDS Wales	0.67	0.61	0.76	0.68	0.52	0.77	0.91	0.73	0.50
WPD S West	0.76	0.94	0.96	0.89	0.70	0.96	0.96	0.88	0.78
CE YEDL	1.00	0.98	1.00	0.99	0.91	0.99	0.94	0.95	0.94
SSE Hydro	0.92	0.94	1.00	0.95	0.81	0.85	1.00	0.89	0.85
SP Distribution	0.98	0.98	0.88	0.95	0.94	0.88	0.88	0.90	0.85
Sector Average	**0.88**	**0.92**	**0.90**	**0.90**	**0.82**	**0.91**	**0.90**	**0.88**	**0.79**

6.4 Model 4 - Opex-CML-Loss

The results for Model 4 shown in Table 13 show that there are overall efficiency savings in CML and loss reduction. Taking an example in the measurement of allocative efficiency, we find that CN West should be able to reduce its input by 44% while maintaining the same output based on its AE score in 2003/04.

This cost-quality-loss model implies that reduction should not be limited to Opex but also to CML and losses at the same time by the same percentage. This 44% of economic loss can be translated into social cost of interruption as £144,624,845 based on 2003/04 figures – i.e. 44%*CML (100.3 minutes)*WTP of CN West (£3,277,097).

Table 13: Model 4 - Average economic efficiency scores

Model 4 OPEX, CML, LOSSES	1990/91-1994/95 TE	1995/96-1999/00 TE	2000/01-2003/04 TE	1990/91-2003/04 TE	1990/91-94/95 AE	1995/96-99/00 AE	2000/01-03/04 AE	1990/91-2003/04 AE	1990/91-2003/04 OE
EDFE EPN	1.00	0.99	0.99	0.99	0.97	0.95	0.80	0.91	0.90
CN East	1.00	0.99	0.88	0.95	0.73	0.79	0.78	0.77	0.73
EDFE LPN	0.99	1.00	1.00	1.00	0.97	0.98	1.00	0.99	0.98
SP Manweb	0.93	0.92	0.95	0.93	0.78	0.96	0.95	0.90	0.84
CN West	1.00	1.00	0.98	0.99	0.63	0.64	0.52	0.60	0.60
CE NEDL	0.91	0.93	0.92	0.92	0.77	0.78	0.84	0.80	0.73
UU	0.98	1.00	1.00	0.99	0.93	0.80	1.00	0.91	0.91
EDFE SPN	0.93	0.99	0.81	0.91	0.83	0.83	0.90	0.85	0.78
SSE Southern	0.94	1.00	0.90	0.94	0.89	0.99	0.88	0.92	0.87
WPD S Wales	0.74	0.80	0.89	0.81	0.54	0.59	0.80	0.64	0.52
WPD S West	0.82	0.97	1.00	0.93	0.70	0.93	0.97	0.87	0.80
CE YEDL	1.00	1.00	0.99	1.00	0.90	0.97	0.95	0.94	0.94
SSE Hydro	1.00	1.00	1.00	1.00	0.89	0.86	1.00	0.91	0.91
SP Distribution	1.00	0.88	0.91	0.93	0.91	0.90	0.83	0.88	0.82
Sector Average	**0.95**	**0.96**	**0.94**	**0.95**	**0.82**	**0.86**	**0.87**	**0.85**	**0.81**

6.5 Model 5- Totex-CML-Loss

Two interesting results present themselves in Model Totex-CML-Loss (Model 5). Firstly, the sector-wide technical score improves and the allocative score worsens when energy losses is added to the model. Secondly, the technical efficiency of DNOs is consistently higher than allocative efficiency over the three review periods. The overall economic efficiency tends to be lower as a result of the multiplication of high technical score and low allocative score. Similar to model Totex-CML, both technical and allocative scores improve over the first two review periods and decline in the third one (Table 14).

At industry level, the allocative efficiency score is relatively low at the beginning of price control review but as the price controls progress, it improves significantly, from 0.83 to 0.89 in the second review period. As the quality incentive plan was introduced by the end of the second price controls in 1999 and came into operation in the third control in 2002, the effect of the program will be seen during the third period. The results indicate that allocative efficiency of DNOs averages about 86% indicating that the incentives set by the regulator for CML and energy loss reduction may not be optimal.

At firm-level, London ranks No. 1 in both allocative and technical efficiency, which implies a balance between number of interruption, expenditure and energy losses. CN West (MEB, Aquila) declines from the No. 1 ranking in technical efficiency to the lowest ranking in allocative efficiency. The dramatic variance in performance of this firm between two scores can be fully explained by its interruption time record, which is the highest of all DNOs. The gap in energy losses (%) between CN West (MEB, Aquila) and DNOs narrows in the third period of review. It is not surprising that from MEB to Aquila and now CN West, the CML keeps exceeding the sector's average (100 minutes) and consistently occupies the upper rank over time.

Table 14: Model 5 - Average economic efficiency scores

Model 5 TOTEX, CML, LOSSES	1990/91-1994/95 TE	1995/96-1999/00 TE	2000/01-2003/04 TE	1990/91-2003/04 TE	1990/91-94/95 AE	1995/96-99/00 AE	2000/01-03/04 AE	1990/91-2003/04 AE	1990/91-2003/04 OE
EDFE EPN	1.00	1.00	1.00	1.00	0.99	0.98	0.87	0.95	0.95
CN East	0.97	0.99	0.98	0.98	0.73	0.86	0.74	0.78	0.76
EDFE LPN	0.99	1.00	1.00	1.00	0.95	0.98	1.00	0.98	0.97
SP Manweb	0.87	0.97	0.95	0.93	0.85	0.94	0.92	0.90	0.84
CN West	1.00	1.00	1.00	1.00	0.64	0.72	0.57	0.64	0.64
CE NEDL	0.90	0.95	0.94	0.93	0.79	0.88	0.83	0.83	0.77
UU	0.98	1.00	1.00	0.99	0.92	0.83	0.94	0.90	0.89
EDFE SPN	0.93	1.00	0.87	0.93	0.84	0.95	0.89	0.90	0.84
SSE Southern	0.92	0.99	0.99	0.97	0.89	0.99	0.84	0.91	0.88
WPD S Wales	0.74	0.80	0.89	0.81	0.57	0.63	0.82	0.67	0.55
WPD S West	0.82	0.99	0.98	0.93	0.73	0.95	0.96	0.88	0.82
CE YEDL	1.00	1.00	1.00	1.00	0.92	0.98	0.95	0.95	0.95
SSE Hydro	1.00	1.00	1.00	1.00	0.90	0.87	1.00	0.92	0.92
SP Distribution	0.98	0.98	0.88	0.95	0.92	0.87	0.86	0.89	0.84
Sector Average	**0.94**	**0.98**	**0.96**	**0.96**	**0.83**	**0.89**	**0.87**	**0.86**	**0.83**

6.6 Efficiency Score Correlation

Table 15 shows the correlation coefficients of the scores between different models with respect to TE, AE and OE. Although Model Opex highly is correlated to Model Totex (Corr. coefficient 0.91), there is a sharp decline in the coefficient when going from the cost-only Model to the quality incorporated model. The correlation with Model Opex (TE) is weaker when the quality dimension is introduced in Model Totex-CML (AE), indicating that one model can explain only 21% features of the other (Corr. Coefficient 0.46). The correlation between the efficiency scores of the total cost-quality models and those of the partial cost or quality models can be interpreted as an indication that such trade-off exists.

At firm-level, London ranks No. 1 in both allocative and technical efficiency, which implies a balance between number of interruption, expenditure and energy losses. CN West (MEB, Aquila) declines from the No. 1 ranking in technical efficiency to the lowest ranking in allocative efficiency. The dramatic variance in performance of this firm between two scores can be fully explained by its interruption time record, which is the highest of all DNOs. The gap in energy losses (%) between CN West (MEB, Aquila) and DNOs narrows in the third period of review. It is not surprising that from MEB to Aquila and now CN West, the CML keeps exceeding the sector's average (100 minutes) and consistently occupies the upper rank over time.

Table 15: Correlation of efficiency scores

	Model 1 Opex TE	Model 2 Totex TE	Model 3 Totex CML TE	Model 4 Opex CML-Loss TE	Model 5 Totex CML-Loss TE	Model 3 Totex CML AE	Model 4 Opex CML-Loss AE	Model 5 Totex CML-Loss AE	Model 3 Totex CML OE	Model 4 Opex CML-Loss OE	Model 5 Totex CML-Loss OE
Model 1 TE	1.0000	-	-	-	-	-	-	-	-	-	-
Model 2 TE	0.9092	1.0000	-	-	-	-	-	-	-	-	-
Model 3 TE	0.7714	0.7755	1.0000	-	-	-	-	-	-	-	-
Model 4 TE	0.5512	0.6295	0.7280	1.0000	-	-	-	-	-	-	-
Model 5 TE	0.6023	0.6835	0.7362	0.9762	1.0000	-	-	-	-	-	-
Model 3 AE	0.4559	0.4076	0.8263	0.4815	0.4596	1.0000	-	-	-	-	-
Model 4 AE	0.5488	0.4726	0.8716	0.4920	0.4665	0.9771	1.0000	-	-	-	-
Model 5 AE	0.5712	0.5362	0.8848	0.4843	0.4611	0.9712	0.9871	1.0000	-	-	-
Model 3 OE	0.6259	0.6023	0.9485	0.6267	0.6140	0.9587	0.9699	0.9740	1.0000	-	-
Model 4 OE	0.6149	0.5680	0.9221	0.7011	0.6694	0.9445	0.9635	0.9496	0.9793	1.0000	-
Model 5 OE	0.6566	0.6507	0.9469	0.6996	0.6823	0.9375	0.9520	0.9615	0.9869	0.9871	1.0000

When energy losses are added to form Model Totex-CML-Loss, the correlation of the results remains low. The correlation coefficients between Model Totex-CML-Loss and other models are an indication of the extent to which the latter models capture the results of the former, thus representing a comprehensive benchmarking which incorporates total costs and quality of service. The integrated Quality-Loss Model is therefore not redundant and is reasonably representative of the measurement. Furthermore, there is a strong correlation between Totex-CML-Loss and Opex-CML-Loss which implies the use of Opex in such a model by the regulator would be acceptable (for this sample).

7. Conclusions

In this paper, we have extended the previous quality-incorporated benchmarking model of Giannakis et al. (2005) and derived a factor price for quality in order to measure allocative efficiency. A longer dataset was used in order to demonstrate the performance trends of DNOs across three price control reviews in line with policy changes that took place. We found that the performance gap in terms of operational cost reduction, under standard benchmarking model, widens over time. More efficient firms improve performance while the remaining firms show a slower rate of improvement. We showed that, some firms performed well in the cost-only models but ranked very low in our cost-quality-loss model. We also found that the correlation coefficients between the cost-only and quality-only scores were somewhat low, consistent with the view that there is potential trade-offs between costs and quality of service.

We found that both the technical and allocative efficiency scores of the firms increased during the first and second price control reviews. However, the scores exhibited a slight decline during the third review period when performance standards for CML and energy losses were tightened. The overall economic efficiency scores classified the performance of utilities into three main groups: – those that scored higher in both technical and allocative efficiency; those that scored higher in technical but low in allocative efficiency scores, and vice versa. Utilities that performed well in both efficiencies were in the minority. In other words, distribution firms that are efficient at utilizing inputs are not necessarily good at choosing the optimal input mix or vice versa.

The relatively lower score in allocative efficiency reflects that the input factor mix is suboptimal with respect to prevailing input prices. While allocative efficiency measures the firm's success in choosing an optimal set of inputs with a given set of input prices, the result implies that there is a mismatch in allocating resources among expenditure, energy losses, and customer minutes lost reductions. This also suggests that DNOs are not incentivized to achieve the correct cost-minimizing bundle of inputs. While the incentives may not be correctly balanced, targeted incentive schemes for costs, quality, and losses are designed to lead the firm towards specific priority areas. However, in this case, DNOs would consistently over or under utilize inputs.

Although the regulator has tightened the quality standard over the years, the DNOs are not directly subject to the real price of quality inputs. Based on our analysis, the social cost of outages is considerably higher than the utilities' current incentive/penalty. True economic efficiency needs to consider optimal responses to price signals rather than engineering proficiency or technical efficiency. Utilities have improved their technical efficiency over the past 15 years. Opex has been significantly declining year by year and DNOs must seek alternative ways to make improvement in economic efficiency. An important step next is to learn to allocate the inputs such as costs, quality, and losses in a holistic approach – i.e. a Totex-CML-loss model is preferable to the Opex-only model. Periodic customer surveys of WTP for quality of service can assist in achieving this aim.

The approach used in this study is a first step in the inclusion of quality in regulatory benchmarking. The next step is to take the effect of environmental factors such as weather on the utilities' costs and service quality. For example, in Norway, weather conditions are included as structural variables in the regression model in order to estimate the expected level of energy not supplied (Langset, 2001). The reason for including weather conditions in specific regions is that they can be correlated with the faults and hence CML and may also be associated with energy losses.

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Appendix I: Ofgem's calculation of Incentive Rate

Incentive rate	: Amount of revenue exposed / Output measure (2004/05)
Output measures	: Final target – Implied worst performance
Implied worst performance	: Final target (2004/05) * Common performance band (%)
Performance band (absolute)	: Final target (2004/05) - average performance for 1995/6 to 1999/00 in CML and CI.

Appendix II: Summary of variables processing (WTP, Bill, Price, Losses, Energy delivered)

Value (££)	**Period**	**Source**	**Formula**
Aggregate WTP	1990/91-2003/04	Calculation	- Sum of Business WTP & Domestic WTP in pounds - Formula 4
Domestic Bill	2003/04	Ofgem-Accent Survey 2003/04	- To calculate the WTP (£) for 2003/04 - Figures for 2003/04 is used to adjust the bill for 1990/91 – 2002/03
Domestic Bill	1990/91-2002/03 2003/04	Calculation	- Electricity Domestic Price * Unit of Energy Delivered (Domestic) - Formula 6 - Figures for 2003/04 is used to compare the actual figure taken from Ofgem's survey
Domestic WTP	2003/04	Ofgem-Accent Survey 2003/04	- Calculation based on the WTP (% of bill) derived from the Ofgem-Accent's WTP survey - Weighted between urban & rural % - Table 6
Domestic WTP	1990/91-2003/04	Calculation	- Weighted Domestic WTP% (2003/04) * Electricity Domestic Price * Unit of Energy Delivered (Domestic) - Formula 5 - adjusted by Domestic WTP (2003/04)
Domestic Electricity Price	1990/91-1993/94	Industry Review Report, Electricity Association, 2002;	- National Domestic electricity price - Adjusted by bill of selected cities to reflect regional variance
Domestic Electricity Price	1993/94 1994/95-2003/04	Energy Price Quarterly Report, DTI, 2006	- Unit price of selected cities - Figures for 1993/94 is used to compare the price from Electricity Association documents of the same year - Formula devised to harmonize the domestic electricity price (1990/91-1993/94)
Business Bill	1990/91-2003/04	Electricity Association, 2002 DTI, 2006 CRI (Centre for the study of Regulated	- Sum of Unit of energy delivered (industrial) * industrial price & Unit of energy delivered (commercial) * commercial price with Levy - National industrial & commercial price is adjusted to reflect pricing variance among DNOs based on the regional weighting factor of the illustrative bill for Medium Size Business.

		Industries), 1998	- Illustrative bill for 1998 serve as basis for adjusting the subsequent years. - Formula 8
Business WTP	2003/04	Ofgem-Accent survey, 2004	- WTP% by DNO reported in Appendix, Ofgem-Accent WTP report - Table 7
Business WTP	1990/91-2003/04	Calculation	- Business WTP% (2003/04) * Unit of Energy delivered (Non-domestic) * industrial & commercial price - Formula 7
Industrial Price	1990/91-2002/03	Energy Price Quarterly Report, DTI, 2002	- National Industrial Price: average price of fuels (electricity) purchased by small, medium, moderately large & very large electricity consumers (exclusive of VAT) - An average of the total sum of price in Quarter 2,3,4 of the previous year & Quarter 1 of the current year - Pricing variance among DNOs is adjusted based on the regional weighting factor of the illustrative bill for Medium Size Business
Commercial Price	1990/91-2001/02	Industry Review Report, Electricity Association, 2002 CRI, 1998	- National Commercial Price (April price of the current year) - Pricing variance among DNOs is adjusted based on the regional weighting factor of the illustrative bill for Medium Size Business
Commercial Price	2002/03	Industry Review Report, Electricity Association, 2002; DTI, 2006; CRI, 1998	- Projected based on the price trend in line with the industrial price - Pricing variance among DNOs is adjusted based on the regional weighting factor of the illustrative bill for Medium Size Business.
Illustrative Bill	1990/91-1998/99	CRI, 1998	- Regional weighting factor is weighted by Unit of Energy Delivered (Non-domestic) by DNO
Illustrative Bill	1999/00-2003/04	CRI, 1998	- Projected based on the weighting factor of 1998/99 bill amount
Loss (￡) in Distribution	1990/91-2003/04	Quarterly Energy Price,DTI, 2006 Ofgem, 1998, 2006	- Average industrial Electricity price without levy (￡) * energy losses (KWh) - Formula 9 and 10
Units of Energy Delivered	1990/91-2003/04	Ofgem and Accent survey, 2004	- Units of Energy Delivered (Domestic) and (Non-Domestic)
** Levy charge begins in 2001 and it represents an average 8% increase on average the price of electricity to industrial customers (Report of Electricity Association, 2003/04)*			