Incentive regulation, productivity growth and environmental effects: the case of electricity networks in Great Britain

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Date:
November 2021

The Productivity Institute
Working Paper No.012

[x] Energy Policy Research Group, Judge Business School

Key words
Total factor productivity, incentive regulation, electricity networks, emissions.

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JEL codes:
D24, H23, L43, L94

Acknowledgements
The authors wish to thank the Office of Gas and Electricity Markets (Ofgem) for their initial encouragement to work on the productivity issue. This paper arises from the work of Ajayi et al. (2018). We particular wish to thank Mark Hogan at Ofgem for his help with data collection. All errors are our own. We acknowledge the financial support of The Productivity Institute, funded by the UK Economic and Social Research Council (grant number ES/V002740/1).

Suggested citation

V. Ajayi, K. Anaya, M. Pollitt (2021) *Incentive regulation, productivity growth and environmental effects: the case of electricity networks in Great Britain*. Working Paper No. 012, The Productivity Institute.

The Productivity Institute is an organisation that works across academia, business and policy to better understand, measure and enable productivity across the UK. It is funded by the Economic and Social Research Council (grant number ES/V002740/1).

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Publisher

The Productivity Institute, headquartered at Alliance Manchester Business School, The University of Manchester, Booth Street West, Manchester, M15 6PB.

Abstract

We analyse the productivity growth of electricity transmission and distribution networks in Great Britain and how changes in incentive mechanism have influenced the measured total factor productivity (TFP). In doing so we are also concerned to examine the effects of quality of service and environmental targets on measured productivity growth. It is increasingly important that productivity measures adjust for the increasing regulatory pressure to reduce the wider societal impacts of the electricity sector and improve quality of service. Failure to do so, may mean that productivity growth may look slower than it actually is.

We employ a DEA technique which considers the underlying data without a stochastic element. Our findings show that productivity growth is consistently low for the period we examine, in the region of 1% p.a. over the 29 years from 1990/1991-2018/2019. For both electricity transmission and electricity distribution we try to monetise a wider range of quality and emissions variables in order to show the difference their inclusion makes to measured productivity growth. We show that it can make a difference both positively and negatively, though often this difference is small (e.g. 0.1% p.a.). However, the impact can be much larger (c. 1% p.a.), especially with respect to improvements in quality of service in the distribution network. In the context of generally slow productivity growth, we therefore show the importance of appropriate measurement.

Incentive regulation, productivity growth and environmental effects: the case of electricity networks in Great Britain[1]

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1. Introduction

In Great Britain, the Office of Gas and Electricity (Ofgem) adopts the price cap incentive regulation approach to regulate the expenditure of the distribution network companies and transmission network companies following the electricity supply restructuring and privatization in 1990. The price cap regulation which is based on RPI-X formula provides the regulated network companies with an incentive to reduce its costs over time. This approach allows for the flexibility of periodic reviews of regulatory regime as cost measurement is separated from price setting[2]. Total factor productivity (TFP) is widely considered a primary concern in the regulation of these industries (Cherchye et al; 2018), with projected TFP growth regarded as one of the most important factors in setting the price cap used for regulating network industries (Lowry and Getachew, 2009). More importantly, changes in incentives set by the regulators in different price control periods influence productivity growth as regulators adjust between an immediate price cut (P_0) in the first year of the price control and the path of prices in the other years of the price control (X). This situation can prompt network companies to alter their expenditures by taking advantage of the initial price reduction to frontload their cost in order to make additional profit.

Efficiency incentives and specific incentives mechanisms are two ways in which incentives are provided in the price control framework (Ofgem, 2009b). Firms are incentivised to attain a higher efficiency in order to lower costs below the target and are allowed to retain the extra profit arising for exceeding the target during the price control period. This may provide an incentive for a firm to distort factor choice by reallocating its input use away from non-capital to capital under the RPI-X regime. However, incentives could be aimed at specific activities in line with the regulators' stated objectives including environmental sustainability or delivery of quality of service provided. Table 1 reports the price control review periods, implemented after privatisation up until the current regulatory regime, for both transmission and distribution network. For instance, the current price control regime, RIIO[3], explicitly set out certain outputs that are expected to be delivered efficiently and that are connected to the allowed revenue set. In addition to the incentives on total expenditure, the current price control places a strong premium on incentives for stakeholder engagement and satisfaction, innovation schemes, as well as delivering a low carbon economy and a sustainable

[2] Price controls usually follow a consultative format by the regulator and setting RPI-X price controls requires an estimate of the revenue that would be enough to fund an efficient business. See Pollitt (2005) on the Ofgem's approach to distribution price control.

[3] RIIO is short for Revenue = Incentives + Innovation + Outputs.

energy sector at a lower cost. We would expect that an energy network sector faced with the need to invest heavily to respond to rising government objectives for the addition of renewables and the promotion of energy efficiency would face rising costs without seeing increased measured outputs. To give a couple of examples of how significant this might be, consider the following. If companies had increased their spending from zero to 2.5% of their totex on such measures (it could be higher than 2.5% under RIIO) this could slow productivity growth by nearly 0.1% per annum (or perhaps 10% of the measured productivity growth). Furthermore, environmental targets which seek to reduce carbon emissions and sulphur hexafluoride (SF6) are impacting on measured TFP. In particular, the regulators are placing much priority on full decarbonisation of the energy sector through the Net Zero target, which has profound effects on the valuation of carbon emissions for network operators in that investment decisions of network companies are subject to the carbon value of projects. Therefore, while it is important to balance incentives for cost reduction with those for environmental sustainability or delivery of quality of service. The need to raise stakeholder satisfaction and increase beneficial environmental outcomes could have implications for measured TFP in regulated network industries. Thus, conventional measures of TFP need to be calibrated to reflect the broader improvements arising from new regulatory incentives and improvements in quality.

One of the most important techniques of measuring TFP in network industries is the Malmquist index which disentangles the sources of productivity growth into different components such as technical change, efficiency change and scale change. The index approach also allows for the comparison of productivity between two time periods and among firms. The most widely used techniques for estimating TFP in regulated industries are parametric method of Stochastic Frontier Analysis (SFA) (Lovell et al., 1994) and nonparametric method of Data Envelopment Analysis (DEA) (Fare et al., 1994). We develop measures of TFP of the network sector based on DEA method on grounds of the methodological simplicity of the technique to the network regulators. DEA has been widely applied in frontier literature to measure the technical efficiency and productivity of decision-making units (DMUs) (see Giannakis et al., 2005; Edvardsen et al., 2006; Ramos-Real et al., 2009; Miguéis et al.,2012; Çelen, 2013).

Table 1: Transmission and distribution price control periods[4]

Transmission

Period	Price control	X-factor	Incentive
1990-1993	TPRC0	RPI-0	The RPI-X regime was based on average revenue cap. Incentives was centred around innovative management skill and losses arrangements.
1993-1997	TPCR1	RPI-3	The RPI-X regime was changed to a total revenue cap. Incentive to increase efficiency and reduce costs. Consideration for capex allowances to allow undergrounding of transmission wires The cost of capital was set at 7%.
1997-2001	TPCR2	P_0 cut: RPI-20 X(1998-2001): RPI-4	Introduction of weighted revenue driver. The cost of capital at 7% retained. The transmission uplift costs incurred by NGC were charged into its price control costs.
2001-2007	TPCR3	X(2001): RPI-0 X(2002-2006): RPI-3	Research and Development (R&D) costs were included in opex allowances for NGET. Introduction of transmission network reliability incentive scheme on 1 January 2005. Separation of System operators (SO) internal cost from the main transmission control.
2007-2013	TPCR4	RPI+2	The RPI+X index was first allowed at a level 2% above inflation. Capex efficiency incentive for TOs with either 25% of the cost borne or the saving benefit received. Target level of performance for each of the Transmission Operators (TOs) with penalties/rewards. Innovation Funding Incentive (IFI) for all the TOs for technological improvements on environmental projects. TOs were allowed to retain any savings achieved under the EU Emissions Trading Scheme (EU ETS). Introduction of an incentive to reduce emissions of this Sulphur Hexafluoride (SF6). Uncertain costs, pension allowance and post-tax capital cost were permitted to be logged up.
2013-21	RIIO-T1		Based on outputs, incentives and innovation as well as total expenditure (totex). Strong incentives for delivering a low carbon economy and a sustainable energy sector at a lower cost. Incentive for TOs to outperform their totex allowance as part of the totex Incentive Mechanism (TIM) Safety obligations with a penalty/reward of 2.5% of the value of any over/under delivery of replacement outputs. Customer satisfaction survey with incentive of up to +/-1% of the sum of base revenue. Attaining existing legal requirements with respect to connections. Environmental target and Environmental Discretionary reward (EDR).

[4] The transmission price control periods are based on National Grid Company (NGC).

			Implementation of the Network Access Policy (NAP) for better planning of outages over RIIO T1 period.
			Distribution
Period	**Price control**	**X-factor**	**Incentive**
1990-1995	DPCR0	RPI+0 to RPI+2.5	Average revenue control implemented. Incentives was centred around innovative management skill and losses arrangements.
1995-2000[5]	DPCR1/2	P_0 cut (1995): RPI-11 to RPI-17 X (1996-2000): RPI-2 P_0 cut (1996): RPI-10 to RPI-13 X (1997-2000): RPI-3	Price control applicable to metering and distribution element. Allowed revenue is based on numbers of customer supplied and volume of units distributed. Incentive to increase efficiency and reduce costs. Provision to double incentive payment introduced for a reduction in losses
2001-2005	DPCR3	P_0 cut:(2000): RPI-23.4 X (2001-2005): RPI-3	Operating expenditures (Opex) are incentivised by benchmarking against the best practice DNOs. Opex efficiency target increased to 4.4% per annum. Incentive mechanisms designed to reduce electrical losses and promote energy efficiency, and improve the quality of service. The quality of service incentives through revenue exposure which are interruption incentive scheme, storm compensation arrangements, other standards of performance, and discretionary reward scheme. 1.2% of revenues exposed is associated with customer interruption and 1.8% tied to customer minute lost.
2005-2010	DPCR4	RPI+0	Strong incentives to undertake efficient cost savings, with a reduction in underlying efficient costs to 1.5%. Information Quality Incentive (IQI) introduced, as well as capex and opex rolling incentives. Special pass through arrangements for Distribute Generation (DG) network access. Incentive in the form of a £/kw revenue driver effected to encourage GD connection. Provision made for pension costs. Significantly increased targets and stronger incentive to achieve quality of service incentive mechanisms. Introduction of Iinterruptions Incentive Scheme (IIS) and Innovation Funding Incentive (IFI).
2010-2015	DPCR5		Incentive mechanisms are tailored to address three themes; environment, customers and networks. Low Carbon Networks fund in the region £500m for new technologies needed for the low carbon economy. losses incentive rewards or penalises DNOs if losses are lower or higher than a target based on historic losses. Mandatory information provision DG Incentive, allowance for undergrounding.

[5] The Office of Electricity Regulation (OFFER) introduced price cuts in real terms of 11–17 percent in distribution charges in 1995/96 and was revised in 1996/97 between 10 and 13 percent.

		Customer satisfaction, complaint handling and stakeholder engagement, Telephony incentive. Customer service reward worst served customer mechanism, interruptions incentive scheme. Equalisation of incentives for operating and capital costs, output measures addressing asset condition and substation utilisation.
2015-2023	RIIO-ED1	RIIO-ED is based on outputs, incentives and innovation. Total expenditure (totex) plays a key role in allowed revenue vis-a-vis DNOs financial performance. Base revenue and incentives are linked to the delivery of outputs. Firms are ranked and those with performance above/below the average will get penalized/rewarded. Reliability and availability output is closely connected with interruptions incentive scheme (IIS). Connections are linked with Time to Connect Incentive (TTC) and incentive on connections engagement (ICE). Customer Service and Social Obligations are associated with broad measure of customer service (BMCS) incentives. Environment output is linked Losses Discretionary reward scheme (LDR) incentive aimed at reducing sulfur hexafluoride (SF6) emission. Network innovation is an important part of RIIO model which comprises of innovation, Network innovation allowance (NIA) and network innovation competition (NIC)

Source: compiled from various Ofgem publications

DEA has many advantages from the perspective of regulators. First, DEA is more attractive to the regulators as it shows the underlying data without a stochastic element. It assumes that the performance of DMUs depends entirely on technical efficiency in productive processes of observed units, which means that any variation between actual and potential output is ascribed to inefficiency and not idiosyncratic error in the data. Second, DEA only considers the efficient observations and creates an enveloped frontier from them by assuming that the observations belong to the same production possibility set, thereby allowing for comparisons between companies. This is quite appealing given the heterogeneities among firms in the network industries in term of output and cost structures. Another important feature of DEA to the regulator is that it does not require the imposition of any functional form for the technology set. Since no priori assumptions on the production possibility set are made, DEA is less susceptible to misspecification regarding the production technology. Thus, DEA is relevant in this case where the regulator faces substantial uncertainty about the technology (Agrell and Bogetoft, 2018). In addition, given the regulatory mandates on quality targets for network companies, the inclusion of exogenous variables such as quality variables in a DEA model provides some useful insights to regulators on how productivity changes between firms and across time periods with changes in quality indicators.

The remainder of the paper is structured as follows. Section 2 presents the literature review and Section 3 sets out the methodologies used in the paper. Section 4 describes the electricity transmission data and results. Section 5 discusses electricity distribution data and our results. Section 6 provides some conclusions.

2. Literature Review

Our review of the existing literature centres on both electricity distribution and transmission networks. Although there is dearth of empirical studies that analyse firms' performance in the electricity transmission sector except Llorca et al. (2016) who examined the US electricity transmission companies for the period 2001–2009 using alternative stochastic frontier models. They identify the determinants of firms' inefficiency and conclude that unit costs fall at a rate of 2.5% per annum over the whole sample period.

However, focusing on electricity distribution, a strand of literature that examines the impact of service quality on electricity distribution productivity rate includes Giannakis et al. (2005), which incorporates quality of service into a DEA model using number of interruptions and customer minutes lost. Giannakis et al. (2005) compute the productivity change indices for 4-year intervals for a panel of 14 electricity distribution utilities in the UK from 1991/92 and 1998/99. The results from the Malmquist indices show that the sector achieved average overall productivity gains of between 12% and 38% for the above 4-year periods between 1991/92 and 1998/99, corresponding to annual TFP growth rates of between 1.5% and 4.75% over the whole sample period. The productivity gains were attributed to reduced efficiency gap among the firms, frontier shift, and improved quality of service.

Productivity growth in the electricity distribution industry has been observed in the context of regulated rate setting. For international comparison, Hattori et al (2005) compare the relative performance of electricity distribution systems in 12 UK regional electricity companies (RECs) and 9 electric utilities in Japan between 1985 and 1998 using both a stochastic frontier and a DEA approach. They find a productivity improvement in the UK sector of 1% p.a. under a price-cap regulation versus 0.3% p.a. in Japan which was using rate of return regulation. Country-specific studies of the impact of regulatory policies on productivity, include Edvardsen et al., (2006), Goto & Sueyoshi (2009), Miguéis et al., (2012), and Senyonga and Bergland, (2018). The impact of incentive regulation on Norwegian electricity distribution productivity growth has been mixed. Controlling for customer density and load factor, Edvardsen et al. (2006) find that average annual productivity growth rates for the Norwegian electricity distribution companies are 1.1% and 2.1% for the two models estimated from 1996 to 2003. Goto and Sueyoshi (2009) estimate a multi-product translog cost function of Japanese electricity distribution from 1983 to 2003 and measure the growth rate of TFP as the sum of technical change and changes in scale economies. Their results show the TFP growth was negative during the entire period, improved by approximately 0.55% p.a between pre-and-post deregulation period. Senyonga and Bergland (2018) find a significant productivity growth improvement with the average annual total factor productivity rate of 1.54% for 121 Norwegian utilities from 2004 to 2012. They conclude that the industry experienced significant improvements in productivity growth in under yardstick competition (2007–2012) when compared to RPI-X incentive regulation (2004–2006). By contrast, Miguéis et al. (2012) find no evidence of a substantial productivity change over time as TFP grows at 0.3% per year model for a sample of 127 Norwegian distribution companies from 2004 to 2007 under RPI-X incentive regulation using forest, snow and coast as environmental variables. Another recent study on Canada such as Dimitropoulos and Yatchew (2017) find a negative productivity growth rate of -1% p.a. for 73 Ontario electricity distribution companies for the period 2002 to 2012 in a price-cap framework.

Other studies have analysed the impact of privatisation on electricity distribution productivity rate and found positive impacts of privatization on TFP using DEA include Pérez-Reyes and Tovar (2009). They examine the trends of productivity of 14 Peruvian distribution electricity distribution companies from 1996 to 2006. The study reveals a positive impact of privatisation on productivity with the average annual TFP growth rate of 4.3%. Çelen (2013) analyse the productivity change of 21 Turkish electricity distribution companies during the period of 2002–2009 using DEA. The author incorporates customer density, customer structure, loss and theft ratio as environmental variables and finds a TFP growth rate of 3.3% p.a. over the sample period. Studies on Brazil include Ramos-Real, et al. (2009) which uses a DEA approach in their study of the Brazilian electricity utilities and distributors during the period 1998 to 2005 while controlling for service area. Assessing the impact of privatisation, the study finds the TFP index witnessed a yearly positive growth rate of 1.3% p.a. over the whole period under analysis for all firms. Meanwhile, Tovar and De Almeida (2011) test the null hypothesis that firm size affects the performance of the electricity distribution industry by calculating productivity development in the Brazilian electricity distribution firms from 1998 to 2005. The results indicate the TFP exhibited a positive annual growth of only 0.9% during the period. They conclude that firm size contributes positively to the change in TFP.

In summary, the literature review shows that empirical literature on productivity growth in energy network industries is mostly concentrated on distribution networks. One important insight from the past studies is that total factor productivity growth for the network industries are examined vis-à-vis different testable hypotheses such as the impact of quality of service, changes in regulation, the effect of privatisation and firm size. Most of the past studies on productivity of energy network industries conducted have tested one or a combination of hypotheses. For instance, studies on the UK test quality of service, privatisation and regulation setting hypotheses; Norway, Canada, Japan and the United States mainly examine the incentive regulation hypothesis, namely that there is a positive impact from introducing incentive regulation on productivity. The studies on emerging economies such as Brazil emphasize privatisation and firm size hypotheses (whether larger firms are more efficient / have faster productivity growth) while studies on Peru and Turkey test primarily an impact of privatisation on network industries' productivity.

In terms of methodology, DEA has typically been the most applied technique, followed by SFA. The overview of the literature indicates, in most cases, overwhelming evidence of positive but low TFP growth, of the order of 1% p.a. Interestingly the studies show some short periods of significantly more rapid growth following privatization, the introduction of incentive regulation or rapid demand growth. However, this is not sustained over long periods, indeed most studies are for short runs of years. There is no evidence that recent growth (since 2005) is likely to be higher than the longer run trend. There are differences among the authors in the choice of variables used in the studies on electricity networks, however there is also a degree of consensus. For electricity distribution, the most frequently used output variables are units of energy delivered and the number of customers, while the most widely used input variables are number of employees, network length, total expenditure and operating expenditure in the electricity distribution network. Customer density, load factors, number of interruptions, customer minutes lost and service areas have been the common quality variables. To our knowledge, no study on electricity network industries has incorporated emission variables to address the extent to which achievement of higher environmental targets and more extensive customer engagement, especially in monetary terms, comes at the expense of measured TFP. Table 2 summarises the literature review.

Table 2: Summary of the literature for electricity network industries

Authors	Method(s)[a]	Data	Variable used[b]	Main findings
		Electricity	**Transmission Network**	
Llorca et al; (2016)	SFA	59 US electricity transmission companies for the period 2001–2009.	O: Peak Load, energy delivered, Network length and total Capacity of Substations C: Total cost IP: Capital price, OM&A input price EX: Distribution line length, service territory area, undergrounding.	The TFP grew at 2.5% per year over the sample periods.
		Electricity	**Distribution Network**	
Giannakis et al. (2005)	DEA	14 UK companies' electricity distribution, 1991/92 and 1998/99	O: Energy sales (kWh), number of consumers, distribution network length (km) I: Operational costs, total operational costs (includes capital costs) EX: number of interruptions (NINT) and customer time lost due to interruptions (TINT)	The average productivity gains of between 12% and 38% for 4-year intervals between 1991/2 and 1998/99, corresponding to annual TFP growth rates of between 1.5% and 4.75% over the whole sample period. The actual contribution of quality of service to TFP was not identified.
Hattori et al. (2005)	SFA and DEA	21 utilities (12 UK RECs and 9 Japanese electric utilities), 1985-1998.	O: Number of customers, electricity delivered I: Total expenditure, operating expenditure EX: Customer density, load factor	The average annual productivity improvement in the UK sector is 1% while the corresponding estimate for the Japanese sector is 0.3%. Increased productivity in the UK is attributed to price-cap regulation as positively

Edvardsen et al. (2006)	DEA Malmquist cost productivity index	Norwegian electricity distributors from 1996 to 2003	O: Number of customers, total energy delivered, Low voltage transmission grid, high voltage transmission grid, expected costs of energy not supplied I: Capital, loss, goods and services, labour, materials, actual costs of energy not supplied C: Total costs IP: interest and depreciation capital rates	The average productivity rate for the panel model and the sample average unit (SAU) are was 1.1% and 2.1% per annum respectively. Change in regulatory regimes affects productivity growth.
Goto and Sueyoshi (2009)	Cost function	9 Japanese electricity distribution companies from 1983 to 2003	O: Number of commercial and industrial customers, and number of household customers C: Total cost IP: Capital price, Labour Price EX: Load factor, customer density Underground ratio of distribution lines	TFP growth was negative during the entire period. TFP improved by approximately 0.55% after deregulation, from -1.810% (the TFP growth in the first period) to -1.255% (the TFP growth in the third period).
Miguéis et al. (2012)	DEA	127 Norwegian distribution companies from 2004 to 2007	O: Energy delivered, customers, Cottage customers I: High voltage lines, Network stations, Interface, EX: Forest, snow, coast	The TFP grew at 0.3% per year over the sample periods. RPI-X incentive regulation has not contributed significantly to productivity growth.
Senyonga and Bergland (2018)	SFA Malmquist	121 Norwegian utilities over for a period of 9-years 2004–2012	O: Number of customers, energy delivered, voltage line and area served. I: Capital, OPEX EX: Underground cable, Customers growth and distance to road.	The average annual productivity growth rate of 1.54% p.a. Significant improvements in productivity growth under yardstick competition (2007–2012) when compared to RPI-X incentive regulation (2004–2006).
Ramos-Real et al. (2009)	DEA Malmquist	18 Brazilian electricity distribution firms from 1998-2005	O: Number of customers, electricity delivered I: Length of electricity grids, number of employee, losses EX: Service areas	TFP index records a yearly positive growth rate of 1.3% in the whole period under analysis for all firms. Privatisation does not seem to have led the firms to be significantly impact of the Brazilian productivity.

Tovar and De Almeida (2011)	SFA	17 Brazilian firms from 1998 to 2005	O: Number of customers, total sales I: Network length, number of employee, losses.	The TFP exhibited a positive annual growth of only 0.9% during the 1998–2005 period. Firm size contributes positively to the change in TFP.
Pérez-Reyes and Tovar (2009)	DEA Malmquist	14 distribution Peruvian companies, for the period 1996–2006.	O: Number of customers, annual sales I: Network length, number of employee, the numbers of MV to LV conversion substations losses	The annual average of the total factor productivity is 4.3%, Significant relationship between the restructuring of distribution sector through the privatization and the enhancement of productivity.
Çelen (2013)	DEA	21 Turkish electricity distribution companies, 2002–2009.	O: Electricity delivered, Number of customer I: Length of distribution line, number of employee, Transformer capacity, Outage hours per customer, Loss&theft ratio, EX: Customer density, Customer structure, Loss&theft ratio, dummies for restructuring and ownership.	The TFP increase by 3.3% per year over the period of 2002–2009. Privatisation contributes significantly to positively to productivity gain.
Dimitropoulos and Yatchew, (2017)	Törnqvist Index, SFA cost function	73 Ontario distributors for the period 2002 to 2012.	O: Number of customers served, energy delivered, and system capacity C: Total cost IP: Capital price, Labour Price EX: regional dummies, Wind speed, Precipitation, Capex/Opex ratio, growth in demand	The productivity growth estimates are approximately -1% per year. Price-cap regulation framework does not significantly impact productivity growth.

[a] DEA: data envelopment analysis, SFA: stochastic frontier analysis
[b]O:Output(s), I:Input(s), EX: environmental variables, C: cost, IP: input price

3. Methodology

3.1 *Data Envelopment Analysis*

DEA is one of the methods commonly used for estimating the Malmquist Index Total Factor Productivity (TFP) change. The construction of a frontier using linear programming (DEA basis), was initially proposed by Farrell (1957). The performance of a decision making unit (DMU) (e.g. a business unit, firm, industry, country) is estimated based on the distance to the frontier technology, which is constructed from the available data. The closer to the frontier, the higher technical efficiency[6]. Charnes, Cooper and Rhodes (1978) were the first to identify the method with the name we currently known as DEA. They proposed a constant return to scale (CRS) model using an input-oriented approach, explained later in this section. Many studies have extended and added more sophistication to the DEA method after that. Banker et al. (1984) propose a variable return scale (VRS) model for DEA[7]. The selection of one or another model (CRS or VRS) depends on different factors. For instance, CRS is appropriate if the firms operate at an optimal scale, however factors such as imperfect competition, regulation, others, may not make this possible (Coelli et al., 2005, p. 172). VRS deals with this issue by separating the scale effect which means that an inefficient firm is benchmarked with firms that have a similar size. CRS and VRS models can also be estimated using two different approaches: input or output oriented. In the input-oriented model inputs are reducing while keeping the same amount of outputs, in the output-oriented model outputs increase while keeping the same amount of inputs[8]. In this study we use the VRS input-oriented model.

3.2 Malmquist TFP index

The Malmquist productivity index was introduced by Caves et al. (1982). The index is estimated using distance function technology. Distance functions, introduced by Shephard (1953), allow the treatment of multiple inputs and multiple outputs combined in a production function. One of the main advantages of distance functions are that they do not require price data or other behavioural

[6] The performance of each DMU (which can be expressed by the ratio of all outputs over all inputs and their specific weights, u and v respectively) needs to be estimated. For instance, if there are N inputs, M outputs, and I firms (DMUs), each DMU can be represented by the column vector x_i and y_i where X represents the N*1 input matrix and Y the M*1 output matrix. Based on the duality of linear programming, this can be solved as follows: $min_{\theta,\lambda,}\theta,\ st\colon -y_i + Y\lambda \geq 0,\ \theta x_i - X\lambda \geq 0, \lambda \geq 0$; where θ is a scalar that represents the efficiency score of the i-th firm and satisfies $\Theta \leq 1$; and λ is a I*1 vector of constants (see Coelli et al., 2005, pp. 162-163 for further details).

[7] This is possible by adding an additional constraint to the original CRS proposal (I1'λ=1, where I1 represents an I*1 vector of ones), explained in the previous footnote. Under VRS technical efficiency scores are equal or higher than those estimated using a CRS.

[8] There is an alternative type of direction, known as the Additive Model (See Cooper et al., 2007, p. 94), which is a combination of both the input oriented and output-oriented models.

assumptions related to cost minimisation and allocative inefficiency[9] (Kumbhakar et al. 2015, p. 27) but only information about inputs and output quantities. The index is built by measuring the radial distance of the observed inputs and outputs in two different periods (t and s for instance[10]) relative to a reference technology. Different indices can be computed depending on the distance technology selected (input or output oriented). Following Caves et al. (1982), the index can be expressed as the geometric average of two indices associated to the period s (Mi^s) and period t (Mi^t) technologies, see Eq. 1:

$$Mi(y^t, x^t, y^s, x^s) = [Mi^s(y^t, x^t, y^s, x^s) * Mi^t(y^t, x^t, y^s, x^s)]^{1/2} \tag{1}$$

Eq. 1 represents the Malmquist productivity index under the input-oriented method (i). The estimation of the index (Mi) requires to compute four different distance functions,

$$Mi(y^t, x^t, y^s, x^s) = \left[\frac{Di^s(y^t,x^t)}{Di^s(y^s, x^s)} * \frac{Di^t(y^t,x^t)}{Di^t(y^s, x^s)}\right]^{1/2} \tag{2}$$

Following Fare (1992), the Malmquist productivity index from Eq. 2 can be represented as follows:

$$Mi(y^t, x^t, y^s, x^s) = \frac{Di^t(y^t,x^t)}{Di^s(y^s, x^s)}\left[\frac{Di^s(y^t,x^t)}{Di^t(y^t,x^t)} * \frac{Di^s(y^s, x^s)}{Di^t(y^s, x^s)}\right]^{1/2} \tag{3}$$

The first component of Eq.3 measures efficiency change (EC) while the second one technical change (TC) based on the input-oriented method. From this we note that $TFP\ growth = EC * TC$. EC captures the change in relative efficiency between period s and t, also known as the catching up term. TC captures the shift in technology between the two periods. The index varies from 0 to infinity between period s and t. A positive growth happens for values greater than 1. The components of the Malmquist productivity index can be estimated using DEA[11]. An enhanced decomposition proposed

[9] In this case the production technology is characterised not only by input and output quantities but by input prices.
[10] Different nomenclatures are used for defining periods: *(s, t), (t, t+1), (0,1).*
[11] The first component can be estimated via DEA, based on the methodology explained in footnote 1. For the second one, which involves cross-time efficiency (period s and t), a modification of the methodology is required as follows: $min_{\theta,\lambda,}\theta,\ st: -y_i(t) + Y(s)\lambda \geq 0,\ \theta x_i(t) - X(s)\lambda \geq 0, \lambda \geq 0$; (Giannakis et. 2005, p. 2262).

by Färe et al. (1994) suggests that EC can be represented by two components, pure efficiency change (PEC) and scale efficiency change (SEC)[12]. The VRS distance function is introduced under this approach. Then Eq. 3 for and input-oriented would be as follows:

$$Mi(y^t,x^t,y^s,x^s) = \frac{Div^t(y^t,x^t)}{Div^s(y^s,x^s)}\left[\frac{SE^t(y^t,x^t)}{SE^s(y^s,x^s)}\right]\left[\frac{Dic^s(y^t,x^t)}{Dic^t(y^t,x^t)} * \frac{Dic^s(y^s,x^s)}{Dic^t(y^s,x^s)}\right]^{1/2} \quad (4)$$

With *v*: VRS, *c*: CRS.

The first component of Equation 4 represents PEC, the second SEC and the last remains the same than Equation 3. Then $TFPgrowth = PEC * SEC * TC$. The last two are decompositions of EC which is computed relative to CRS while PEC is calculated under VRS. SEC represents a residual scale component that represents changes in the deviation between CRS and VRS technologies, see Färe et al. (1994, pp. 74-75). One of the main observations made to the decomposition proposed by Färe et al. (1994) was the assumption of using CRS and VRS within the same decomposition of the Malmquist index creating issues of internal consistency (Ray and Desli, 1997). The authors propose a different decomposition where only the PEC component remains the same. In their proposal, TC is computed using the geometric mean of the ratios of VRS distance functions while in Färe et al. (1994) this refers to the ratios of CRS distance functions. In the estimation of SEC, the geometric mean of scale efficiencies was used (instead of the simple ratio of the two bundles) but with both referring to VRS technologies as the benchmark, see Ray and Desli (1997, p. 1036).

4. Electricity Transmission Network

4.1. Transmission data

Selecting the input–output variables is an important step in DEA. To model the technology of electricity transmission, we have to specify the relevant measures of inputs, outputs, and other quality factors. The selection of the variables for our study of electricity transmission is based on the availability of data and the current literature. The summary statistics of the variables used in this section are reported in the Appendix, Table A1. We obtain data from Ofgem for the 1990/91–2018/19 period for the 3 electricity transmission network companies in Great Britain: National Grid (NGET), Scottish Power (SPET) and Scottish Hydro-Electric (SHETL). Due to the small number of electricity transmission companies involved in the analysis and the fact that the companies are not comparable

[12] SEC captures the contribution of scale economies to productivity growth.

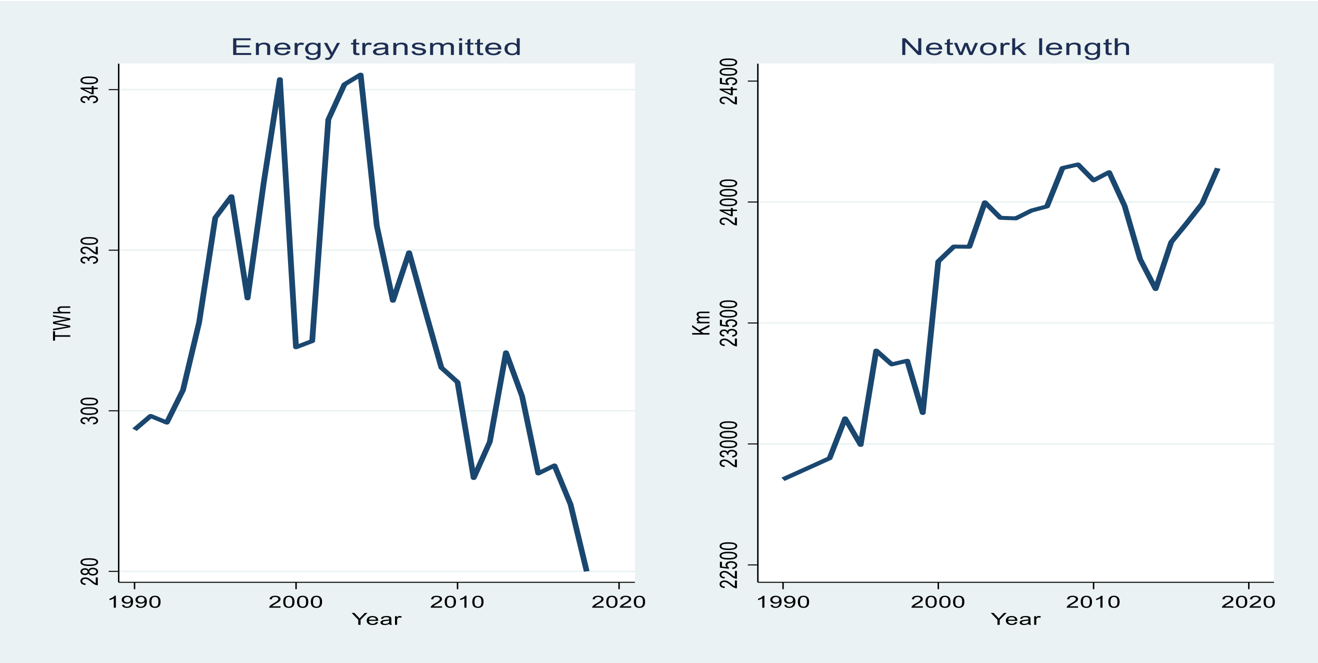
in size, the data was aggregated together to analyse overall industry performance (i.e. a single aggregate firm evolving through time). This data covers the price control periods TPCR0 (1991-93), TPCR1 (1993-1997), TPCR2 (1997-2001), TPCR3 (2001-07), TPCR4 (2007-13) and RIIO-ET1 (2013-21)[13].

The output variables used for the electricity transmission network performance analysis are units transmitted and network total length. Energy transmitted is measured in Terawatt hours (TWh) and network length in kilometre (Km). We include peak demand measured in Gigawatt (GW) in the alternative models, as it is one variable which drives the size and cost of the network. Fig.1 shows the trends in the main output variables: energy transmitted and network length. Contrary to most of the existing literature which have used physical measures of inputs, we rely on monetary values of inputs to evaluate the performance of regulated firms using either operating expenditure (Opex) and capital expenditure (Capex) as our main inputs. We adjusted expenditure data (for electricity and gas) using capital goods index to deflate capital expenditure and wage index to deflate operating expenditure. Data on these indices are obtained from the ONS database. These variables are modelled separately as inputs as opposed to single input total expenditure. We consider quality variables in the analysis of electricity transmission network performance, value of lost load (VoLL), transmission system non-availability and emission variables - business carbon footprint and SF6 emissions. Considering that most quality variables often reflect the impact of the operating environment, we monetised these variables and adjust operating expenditure with the cost equivalents of the quality variables. Both business carbon footprint and SF6 emissions data are recently being reported by Ofgem in the current price control period, RIIO-1, starting from 2013/2014, and their valuation only covers this period. To calculate the cost of business carbon footprint, we multiple quantity of business carbon footprint expressed in tCO2e by annual social price of carbon measured in £/CO2 expressed in 2012/13 prices and obtained from by the Department of Energy and Climate Change and Department of Business, Energy & Industrial Strategy [14].

[13] NGET is very much bigger than both SPET and SHETL as it accounted for over 92% of average electricity transmitted during the sample period of 1990/91-2018/19. We take the price control periods for NGET as defining our price control periods as shown in Table 1 because it covers most of the sector.

[14] The social price of carbon is the short-term traded carbon value used by Ofgem and for other UK public policy appraisal prepared by the Department of Energy and Climate Change and Department of Business, Energy & Industrial Strategy. This measures the value of additional carbon savings not directly priced in emissions allowance prices and carbon taxes. We use the values of central scenarios as reported in the document titled "Updated short term traded carbon values for UK public policy appraisal" in the link below: https://www.gov.uk/government/publications/2012-update-to-carbon-valuation-methodology-for-uk-policy-appraisal. See Appendix II for the calculation of the emission costs.

Fig. 1: Annual evolution of outputs for electricity transmission sector



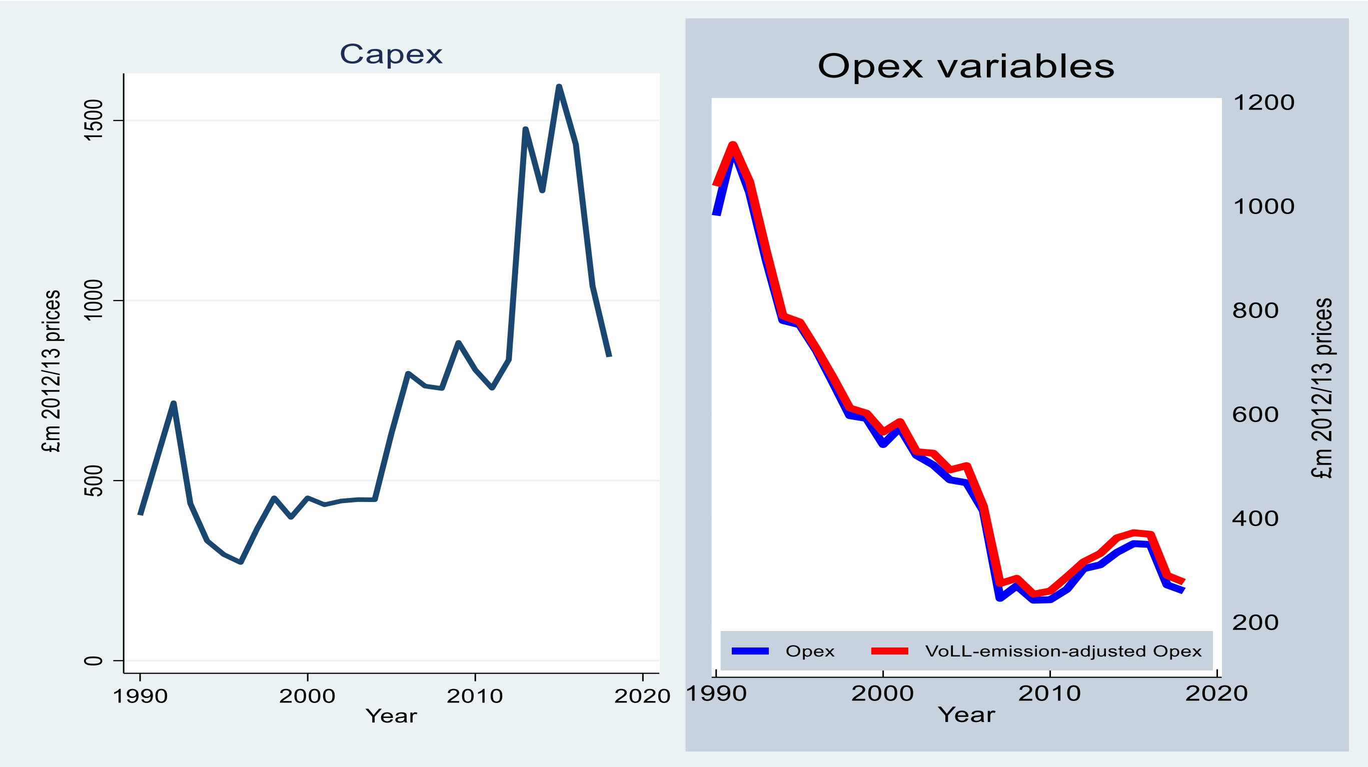
Following the approach for calculating the carbon dioxide equivalent quantity of a fluorinated greenhouse gas as outlined by the UK Department for Environment, Food & Rural Affairs and Environment Agency, we convert SF6 emission measured in kilogram (kg) to tCO2e using SF6 global warming content[15]. Afterwards, we compute the cost of SF6 emission as a product of the quantity of SF6 emission (tCO2e) and social price of carbon. For the monetisation of VoLL, we use £17,000/MWh in 2012/13 base year, being consumers' willingness to accept (WTA) payment for loss of load[16]. We calculate VoLL cost by multiplying WTA value by energy not supplied. Since the emission and VoLL costs are ancillary costs which tend to affect the operating performance of the network firms, we add the costs to Opex and they are treated as input in the alternative models accordingly as shown in Table 3. However, transmission system non-availability is not monetised but measured in kilometre (km) which is calculated as system non-availability expressed in

[15] The formula for calculating CO2 equivalent and global warming potential value for SF6 and other fluorinated greenhouse gases are reported in this link: https://www.gov.uk/guidance/calculate-the-carbon-dioxide-equivalent-quantity-of-an-f-gas.

[16] The value of £17,000/MWh was obtained from National Grid Transmission as the figure was used for Electricity Market Reform (EMR) in the Capacity Market on based on a study conducted by London Economics (2013). It is a weighted average based on consumers' willingness to accept (WTA) payment for loss of load on weekday, winter evening peak.

percentage multiplied by network length expressed in km i.e., the fraction of the transmission network that is unavailable.

Fig. 2: Annual evolution of inputs for electricity transmission sector



System non-availability is treated as an input because it has the property that reductions in this variable, ceteris paribus, improves productivity. Fig. 2 shows the trends in some input variables. We specify six different types of DEA models, which employ different combinations of the variables. The objective is to assess policy issues related to the DNOs' productivity from the perspective of inputs-outputs variables as well as quality and emission variables. Model 1 is the basic model which comprises of two outputs: energy transmitted and network total length; and two inputs: Opex and Capex. Model 2 is a variant of the basic model but adjusts for Opex with VoLL cost, thereby specifying two outputs and two inputs. The emission variables by network firms are valued using social price of carbon and are included with VoLL cost in the Opex input in Model 3. Models 4-6 are extended versions of Models 1-3 where we include peak demand and system non-availability directly as output and input accordingly into the production technology. Table 3 summarises the six models used in our transmission network TFP analysis.

Table 3: *Overview of Models for Electricity Transmission*

Model	**Model1**	**Model2**	**Model3**	**Model4**	**Model5**	**Model6**
Output:						
Energy transmitted	✓	✓	✓	✓	✓	✓
Network length	✓	✓	✓	✓	✓	✓
Peak demand				✓	✓	✓
Input:						
Capex	✓	✓	✓	✓	✓	✓
Opex	✓			✓		
VoLL cost adjusted Opex		✓			✓	
VoLL and emission costs adjusted Opex			✓			✓
Quality variable:						
System non-availability				✓	✓	✓

VoLL: value of lost load.

Given that the quantities of physical outputs delivered by distribution utilities are due to the derived nature of electricity demand, beyond the control of the management, we use input-oriented DEA models[17] to calculate the DNOs' relative efficiency in terms of the extent by which they can reduce their inputs while maintaining a given level of output as the main goals of these companies should be to minimize inputs without changing outputs. For the electricity transmission network, we analyse the overall industry performance (one firm evolving through time) as the three constituent transmission companies are not comparable.

4.2 *Transmission results and discussion*

The Malmquist productivity index is based on the DEA model and its decomposition is calculated for each year relative to the previous year as specified in equation (4). The results for the total factor productivity change and its components from the DEA models using (variable returns to scale) VRS technology structures are presented in line with Ofgem's distribution price control review regime. Given that the electricity transmission network is treated as single firm, the company cannot be assessed against another unit. In effect, its own efficiency against itself will be unity, although the productivity against itself overtime can be computed. Hence, it cannot be decomposed as there is no

[17] Input-oriented models are often used in a DEA model if a DMU can reduce its inputs while keeping the outputs at their current levels. Output-oriented models are used if a DMU can increase its outputs while keeping the inputs at their current levels. The choice of input- or output-oriented models depends upon the production process characterizing the firm (i.e. minimize the use of inputs to produce a given level of output or maximize the level of output given levels of the inputs). For the purpose of estimating network industries' performance, the input-oriented DEA measures are more applicable.

efficiency boundary being the sole DMU in the DEA model. Therefore, we compute the TFP from the estimated DEA model by employing a Malmquist productivity index over the period 1990/991–2018/2019 for six alternative models. This computation is equivalent to the geometric mean of output and input ratios. Index values higher than 1 indicate productivity improvement while values lower than 1 represent productivity regress.

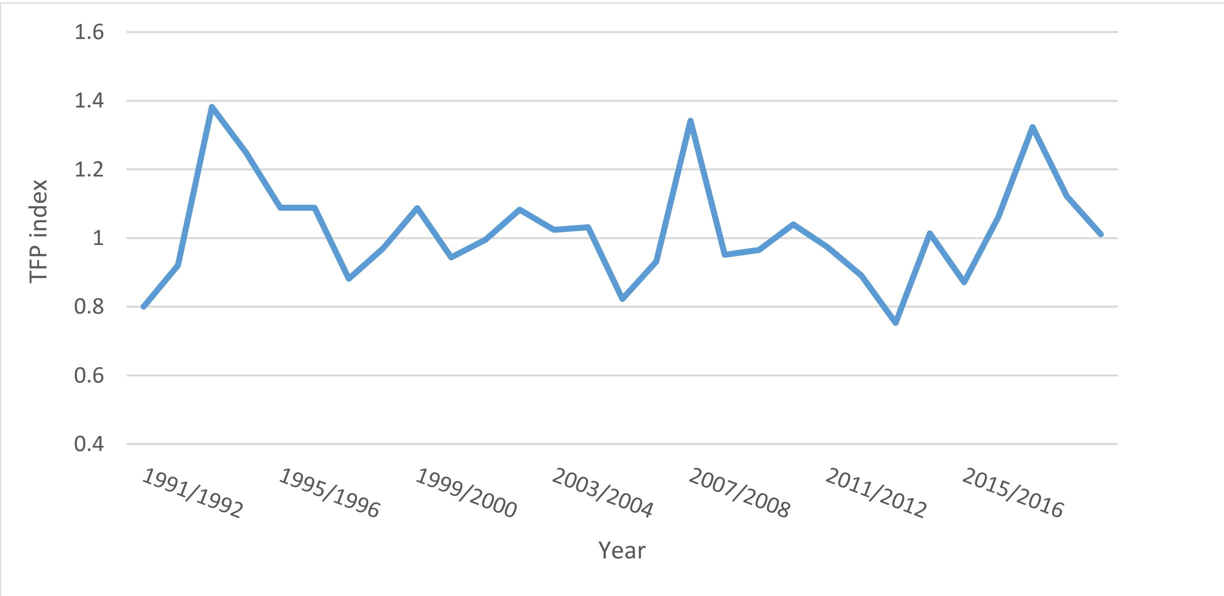
Table 4: Transmission Total Factor Productivity Change Models 1-6

Year	Model 1	Model 2	Model 3	Model 4	Model 5	Model 6
1991/1992	0.800	0.821	0.821	0.847	0.847	0.847
1992/1993	0.921	0.914	0.914	0.896	0.889	0.889
1993/1994	1.382	1.382	1.382	1.413	1.413	1.413
1994/1995	1.249	1.254	1.254	1.220	1.225	1.225
1995/1996	1.088	1.090	1.090	1.016	1.016	1.016
1996/1997	1.088	1.089	1.089	1.096	1.097	1.097
1997/1998	0.881	0.877	0.877	0.882	0.878	0.878
1998/1999	0.970	0.966	0.966	0.970	0.966	0.966
1999/2000	1.087	1.091	1.091	1.087	1.091	1.091
2000/2001	0.944	0.932	0.932	0.944	0.932	0.932
2001/2002	0.995	1.007	1.007	1.045	1.057	1.057
2002/2003	1.083	1.087	1.087	1.083	1.087	1.087
2003/2004	1.024	1.009	1.009	0.955	0.940	0.940
2004/2005	1.031	1.033	1.033	1.032	1.033	1.033
2005/2006	0.823	0.811	0.811	0.823	0.811	0.811
2006/2007	0.932	0.954	0.954	0.932	0.954	0.954
2007/2008	1.342	1.284	1.284	1.279	1.223	1.223
2008/2009	0.951	0.978	0.978	0.950	0.959	0.959
2009/2010	0.965	0.968	0.968	0.999	0.999	0.999
2010/2011	1.040	1.029	1.029	0.954	0.954	0.954
2011/2012	0.974	0.964	0.964	0.942	0.942	0.942
2012/2013	0.891	0.911	0.911	1.022	1.044	1.044
2013/2014	0.753	0.764	0.744	0.728	0.739	0.724
2014/2015	1.014	1.011	1.007	1.022	1.020	1.016
2015/2016	0.871	0.879	0.881	0.911	0.911	0.911
2016/2017	1.061	1.059	1.063	1.047	1.047	1.047
2017/2018	1.323	1.323	1.316	1.313	1.313	1.313
2018/2019	1.122	1.123	1.123	1.043	1.043	1.043
Mean	**1.011**	**1.012**	**1.010**	**1.006**	**1.006**	**1.005**

Model 1= unit transmitted, network length, Capex and Opex
Model 2= unit transmitted, network length, Capex and VoLL-adjusted Opex
Model 3= unit transmitted, network length, Capex, VoLL-emissions-adjusted Opex
Model 4= unit transmitted, network length, peak demand, Capex, Opex and system non-availability
Model 5= unit transmitted, network length, peak demand, Capex, VoLL-adjusted Opex and system non-availability
Model 6= unit transmitted, network length, Capex, peak demand, VoLL-emissions-adjusted Opex and system non-availability

The average annual total factor productivity for Models 1-6 is reported in Table 4 The Malmquist index summary of annual geometric means when the year 1990/1991 is set as the base period to be the reference point for observing the annual changes. We discuss the total factor productivity change (TFPC) for the models as no decomposition can be achieved in the case as all change in TFPC is attributable to technical change. We begin our discussion with Model 1 which is the baseline model that considers only the conventional measures of TFP without adjusting for improvements in quality and reduction in environmental emission variables using the standard inputs and output, the results indicate that the sector experienced an average annual TFP growth rate of 1.1% per annum over the whole sample period.

Fig. 3**:** Average Annual Total Factor Productivity Change in Models 1



The trend of average annual productivity growth for Model 1 is displayed in Fig. 3. The TFP growth reached the peak between 1992/93 and 1993/94, growing at 38.2%. Incidentally, these periods mark the interface between the end of the RPI-X regime originally implemented after privatisation and the beginning of the first price control review (TPCR1). The second highest TFP growth of 34.2% was recorded between 2006/07 and 2007/08, which coincided with the beginning of the third (TPCR3) and fourth (TPCR4) price control periods. Obviously, these excessive high TFP growth rates between the end of one price control period and the beginning of another price control period underscore the fundamental effect of the changes in incentives set by the regulators as they influence productivity growth, particularly as they are usually notified prior to the period of implementation, which enables the companies to alter the input use.

In Model 2, VoLL is valued and Opex is adjusted with the estimated cost. The adjustment of Opex by adding VoLL cost to Opex input in Model 2 marginally increased the overall average annual TFP growth from 1.1% to 1.2%. This result suggests that the ability of transmission firms to sufficiently reduce the cost associated with energy not supplied by optimally transmitting energy to the distribution chain could enhance their productivity. The emission variables by network firms are valued using social price of carbon. However, the average annual TFP growth decreased by 0.2% when both VoLL and emission costs are included in the Opex input in Model 3. This implies that the inclusion of carbon emissions and SF6 leakages does impact the measured TFP in transmission network sector, but not positively.

In Models 4-6, we include peak demand and system non-availability directly as output and input respectively into the production technology of Models 1-3. Comparing Model 1 to Model 4, which serves as a benchmark model, TFP growth reduced from 1.1% p.a.in Model 1 to 0.6% p.a. in Model 4 when controlling for peak demand and system non-availability. In the same vein, the inclusion of these two variables decreased the TFP growth from 1.2% p.a. in Model 2 to 0.6% p.a. in Model 5 as well as a further decline in TFP growth from 1.0% p.a. in Model 3 to 0.5% p.a. in Model 6. Thus, including peak demand as an output reduces measured productivity growth.

To gain more insights into the impact of incentives on productivity, we present the TFP results in accordance with transmission price control reviews in Table 5. It is interesting to note that the highest TFP growth occurred in the first price control period, TPCR1, averaging between 17.7% - 19.8% p.a. across the six models. The period lies between when RPI-X regime was applied to customer charges per MW, in the form of an average revenue cap following privatisation, and when it was amended to a total revenue cap as part under first price control review period beginning in 1993/1994. This period of peak TFP growth across the models can also be explained by the incentive to increase efficiency and reduce costs arising from the reduction target of X-factor value from 0% in 1992/1993 to 2% in 1993/1994 for National Grid Company, as well as the inclusion of capex allowances to permit undergrounding of transmission wires (Ofgem, 2009).

Table 5: Annual Total Factor Productivity Change by Price Control Models 1-6

TPCR	Model 1	Model 2	Model 3	Mode l4	Model 5	Model 6
TPCR0	0.858	0.866	0.866	0.871	0.868	0.868
TPCR1	1.196	1.198	1.198	1.177	1.179	1.179
TPCR2	0.968	0.963	0.963	0.968	0.964	0.964
TPCR3	0.978	0.979	0.979	0.974	0.976	0.976
TPCR4	1.018	1.016	1.016	1.018	1.016	1.016
RIIO-ET1	1.008	1.011	1.006	0.995	0.997	0.993
Whole Period	**1.011**	**1.012**	**1.010**	**1.006**	**1.006**	**1.005**

In addition to the positive TFP growth of TPCR1, Table 5 shows that the last price control review period (TPCR4) also experienced positive TFP growth across the models. The TFP growth of the current price control review period (RIIO ET-1) is was positive in the first models but much lower than the TFP growth of the corresponding models in TPCR4. It is instructive, however, that the productivity growth of the RIIO ET-1 is negative in the last three models when peak demand and system non-availability are controlled for. This might be connected to, among other things, the special attention being paid to mandatory polices such as the implementation of the Network Access Policy (NAP) under this regulatory regime to improve stakeholder satisfaction as well as emission targets that are fully operational in this period as regulators are placing much priority on full decarbonisation of the energy sector through the Net Zero target. This is having profound effect on the valuation of carbon emissions for network operators in that investment decisions of network companies are subject to the carbon value of projects. Meanwhile, negative productivity growth was recorded in the period following privatization, the second and third review periods, which strongly offset the TFP gains recorded in the other periods. Nevertheless, the overall TFP growth of the transmission network was still positive for the whole sample period.

5. Electricity distribution network

5.1 Distribution data

The basic design features of electricity distribution systems and the technologies used in them are similar the world over, but comparative productivity analysis studies have adopted different input and output variables. Thus, there is no general consensus on which variables best describe the operation of distribution utilities. In our case, the choice of variables is based on the availability of data , the existing literature and on Ofgem's own use of outputs with corrected ordinary least-squares (COLS) technique (see Jamasb and Pollitt, 2007). We have data for the 14 distribution network operator areas from Ofgem for the 1990/91–2018/19 period. Data are used in quantities where available; expenditures are measured in million pounds 2012/13 prices. The expenditure data are normalized using capital good index and wage index obtained from the ONS database (see Appendix II).

Table 6: *Overview of Models for Electricity Distribution*

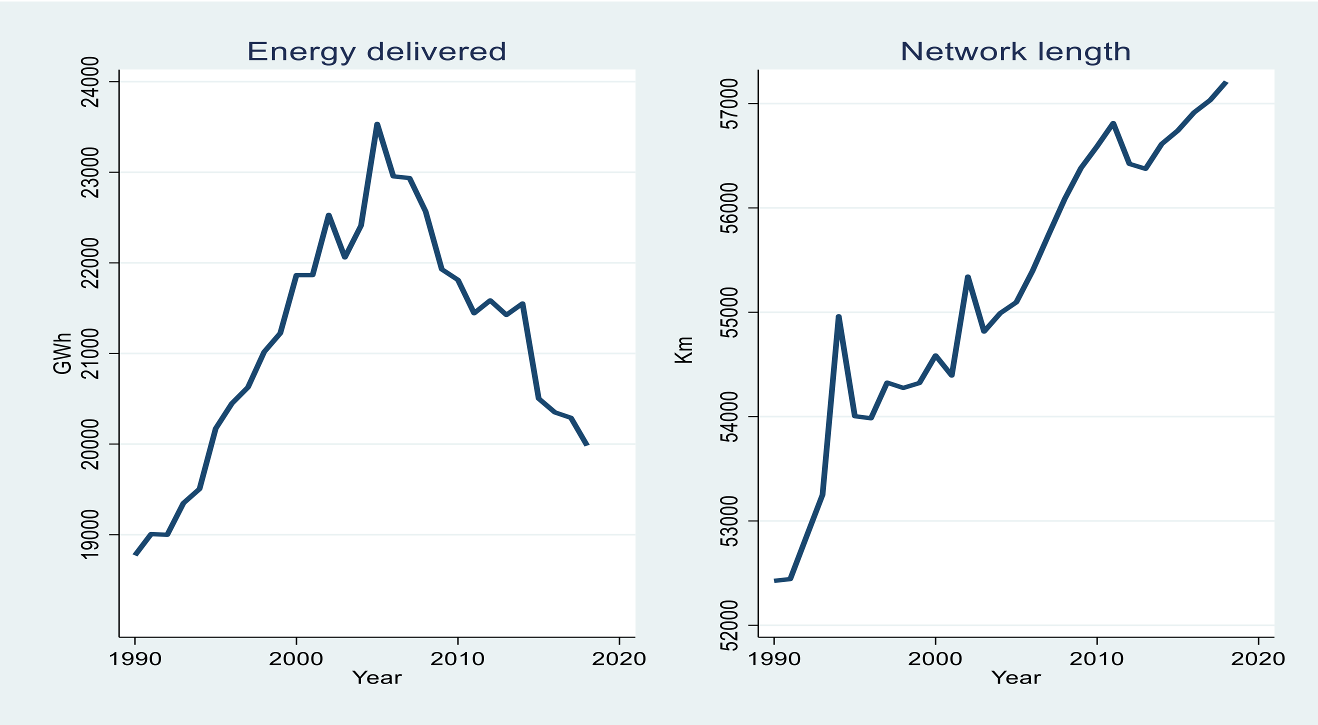
Model	**Model 1**	**Model 2**	**Model 3**	**Model 4**	**Model 5**	**Model 6**	**Model 7**
Output:							
Energy distributed	✓	✓	✓	✓	✓	✓	✓
Customer number	✓	✓	✓	✓	✓	✓	✓
Network length	✓	✓	✓	✓	✓	✓	✓
Peak demand				✓	✓	✓	✓
Input:							
Capex	✓	✓	✓	✓	✓	✓	✓
Opex	✓						
CML cost adjusted Opex		✓		✓			
CML and losses costs adjusted Opex			✓		✓	✓	
CML- losses and emission costs adjusted Opex							✓
Quality variable:							
Customer satisfaction						✓	✓

CML: customer minutes lost.

Table A2 from the Appendix summarizes the inputs, outputs, and quality attributes used in the models where quality attributes are treated as inputs as discussed below. We discuss the choice of inputs, outputs and the monetisation quality factors used in the distribution network. Table 6 summarises the seven models that are discussed in this section.

First, we turn to outputs measures of the distribution networks, our review of productivity studies of electricity distribution utilities shows that the most widely used output variables are units of energy delivered and the number of customers as the cost of distribution services varies according to both. Since the product of a distribution utility is a set of specific quantities of electricity distributed to particular geographic locations, network length captures the extent of that geographical area. Following Giannakis et al (2005), we use units of energy delivered, number of customers and network length. We also consider peak demand as part of output in the alternative models estimated in the report. Although, it has been argued that peak demand can be priced separately, nevertheless, we included it in the alternative models as it is one variable which drives the size and cost of the network. The units of energy delivered is measured in GWh and network length measured in km. Fig. 5 shows the average annual evolution of the output variables; energy delivered, number of customers and network length. Consistent with the past studies on distribution network, we use both Opex and Capex as our main input measures. We have also treated them as separate inputs having deflated Capex annually by a capital goods index data and Opex by a wage index.

Fig. 5: Average Annual evolution of outputs for the electricity distribution sector

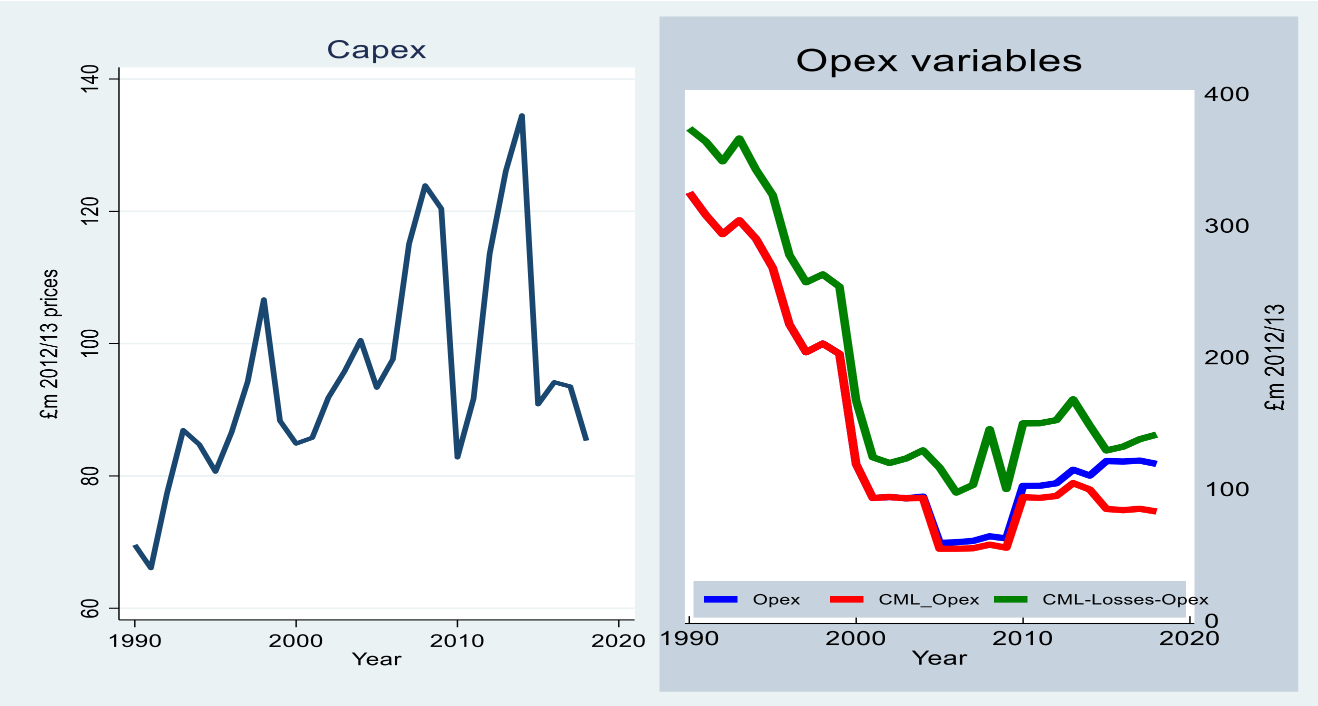


Furthermore, we monetise the quality and environmental variables in our models and adjust Opex with the monetised value of these variables. Due to paucity of data, we focus primarily three important quality variables; customer minutes lost (CML), customer satisfaction (CS), energy losses as well as two emission variables; SF6 and business carbon footprint, since a reduction in these variables is regarded as desirable to the consumers, distribution firms and the regulator. Energy losses affect power supply because more losses mean that the distribution companies have to increase overall generation, in order to supply the same levels of electrical energy. To monetise CML, we calculate the rewards or penalties associated with trend of CML by subtracting annual actual target from 2002/2003 base year target [18]. The CML trend is then

[18] In order to strengthen the incentives on distribution companies to deliver the appropriate quality of service to consumers, Ofgem introduced an incentive scheme on 1 April 2002 which penalises or rewards DNOs which are below or exceed their target for customer minutes lost on their rate of improvement in performance. See Appendix II for the calculation.

multiplied by the incentive rate expressed in £m per CML to obtain the CML cost or gain. The incentive rate is deflated using wage index. We calculate the cost of energy losses by multiplying distribution losses in MWh by average annual UK wholesale electricity prices expressed in £/MWh[19]. The costs of emission variables are calculated in a manner analogous to transmission network starting, spanning the current price control period.

Fig. 6: Average Annual evolution of inputs for the electricity distribution sector



We adjust Opex using the monetised values of quality variables and are treated as inputs, meaning that ceteris paribus, a reduction in their values would increase their productivity. In order to include customer satisfaction in a DEA model, we multiply the values by the number of customers, to make the variables scalable and treat as output. Fig. 6 shows the average annual evolution of the input variables.

[19] We use the UK annual spot average price series (UKPX Reference Price Data) from 1990/91 - 2018/19 as wholesale electricity price. We thank David Newbery for sharing the electricity price series with us.

5.2 Distribution results and discussion

We compute the distribution TFP and its components from the estimated DEA model using a Malmquist productivity index as specified in equation (4) across seven models over the period 1990/1991–2018/2019. Although the Malmquist indices calculated could fluctuate from one year to the next, the length of the period under study allows us to examine the productivity trend under different price control subperiods First, we consider Model 1, the baseline model which does not account for the quality and emission variables.

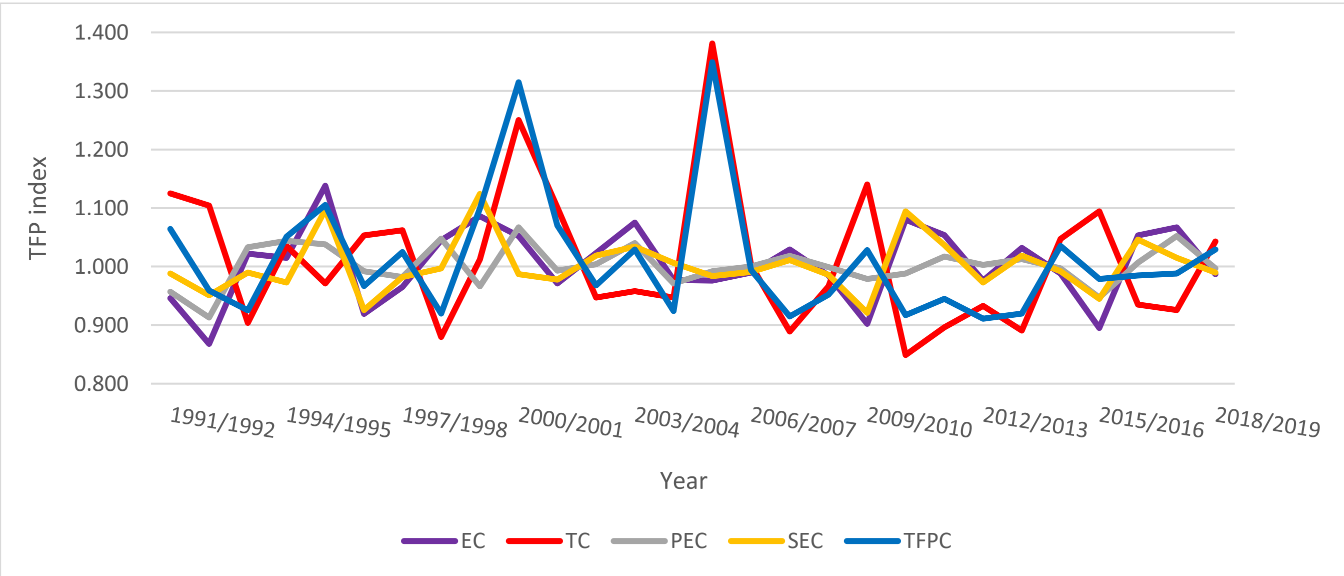
Table 7: *Total Factor Productivity Change and its Components- Model 1*

Year	EC	TC	PEC	SEC	TFPC
1991/1992	0.946	1.125	0.957	0.988	1.064
1992/1993	0.868	1.104	0.913	0.951	0.959
1993/1994	1.022	0.904	1.033	0.990	0.925
1994/1995	1.015	1.035	1.044	0.973	1.051
1995/1996	1.138	0.971	1.038	1.097	1.105
1996/1997	0.919	1.053	0.992	0.926	0.967
1997/1998	0.965	1.062	0.982	0.982	1.025
1998/1999	1.045	0.880	1.048	0.997	0.920
1999/2000	1.086	1.012	0.966	1.124	1.099
2000/2001	1.052	1.250	1.067	0.987	1.315
2001/2002	0.971	1.101	0.993	0.978	1.070
2002/2003	1.023	0.947	1.004	1.019	0.968
2003/2004	1.075	0.958	1.040	1.034	1.029
2004/2005	0.977	0.947	0.971	1.006	0.924
2005/2006	0.976	1.381	0.992	0.984	1.349
2006/2007	0.990	1.003	1.000	0.991	0.994
2007/2008	1.029	0.889	1.018	1.011	0.915
2008/2009	0.985	0.966	0.999	0.986	0.952
2009/2010	0.902	1.140	0.979	0.921	1.028
2010/2011	1.080	0.849	0.988	1.094	0.917
2011/2012	1.054	0.896	1.017	1.037	0.945
2012/2013	0.976	0.933	1.003	0.973	0.911
2013/2014	1.032	0.891	1.013	1.019	0.920
2014/2015	0.988	1.047	0.997	0.992	1.035
2015/2016	0.895	1.094	0.947	0.945	0.979
2016/2017	1.053	0.935	1.007	1.046	0.985
2017/2018	1.067	0.926	1.052	1.015	0.988
2018/2019	0.987	1.043	0.997	0.990	1.029
mean	**1.002**	**1.006**	**1.001**	**1.001**	**1.008**

Table 7 reports the Malmquist index summary of annual geometric means when the year 1990/91 is set as the base reference point for observing the annual changes. It presents our results for the model where total productivity change index is decomposed into efficiency change (EC), technical change (TC), pure efficiency change (PEC), scale efficiency change (SEC), and total factor productivity change (TFPC). The results indicate that the distribution network companies experienced an average TFP growth rate of 0.8% p.a. over the whole sample period. The indices for average productivity growth show that average technical changes i.e., the shift in technological frontier, accounts for most of the growth in productivity, averaging 0.6% p.a. The sector recorded average efficiency change of 0.2% p.a. and scale change inefficiency of 0.1%.

Fig. 7 illustrates the evolution of total factor productivity change and its components over the period 1990/91–2018/19 for Model. The index decomposition shows that TFP wanders through the sample period. Efficiency change also meanders considerably mirroring the pattern of TFP change. The highest TFP growth of 34.9% was recorded between 2004/2005 and 2005/2006 which marked the period road which coincided with the end of the third ((DPCR3) and the beginning fourth (DPCR4) price control period.

Fig. 7: Total Factor Productivity Change and its Components



Drawing on the price control review in Table 1, we investigate the how changes in the incentives mechanism have reflected on our estimated productivity by presenting our results for the average of each price control periods as sub-periods 1990/91-1994/95, 1995/96-1999/2000, 2000/2001-

2004/2005, 2005/2006-2009/2010, 2010/2011-2014/15 and 2015/16-2018/2019. The first, second, third, fourth and fifth sub-periods represent corresponding distribution price controls, and the last sub-period corresponds to first part of the current RIIO price controls. The price control review is more comprehensive for distribution network as it covers all the 14 network operators. For instance, the first distribution price control (DPCR0)[20] was put in place by the government and executed by the Department of Energy at the time of restructuring and permitted price increases that ranged up to 2.5 percentage points above the inflation rate so as provide incentives for efficiency, innovation and enhance conditions to that promote competition (Offer, 1994)[21]. In August 1994, for the second distribution price control review (DPCR1/2) for 1995/96–1999/2000 (which was reopened in 1996), Offer introduced reductions averaging 14 per cent in final electricity prices to take effect in the first year. Distribution charges were, thereafter, required to fall by an X-factor of 2 per cent p.a. in real terms for the duration of the price control review. The third price control review (DPCR3) for 2000/01–2004/05 introduced further cuts on distribution businesses averaging 3 per cent for the next 5 years, with an initial cut in RECs' distribution revenue by about 23.4 per cent. This amounted to an overall initial revenue cut of £503 million at 1995 prices (Ofgem, 1999a). In April 2005, the fourth price control review (DPCR4) was introduced when prices were allowed to increase in line with inflation (i.e. X = 0). It allowed for investment of £5.7 billion over the years 2005 – 2010 to deliver improved performance and represented a significant increase in capital expenditure (Ofgem, 2004). The fifth distribution price control review (DPCR5) was introduced in April 2010 and allowed the DNOs a 20 per cent increase (or £2.3bn) on expenditure in DPCR4. This represents an 8 per cent (or £1.3bn) reduction from the forecasts in the DNOs' business plans (Ofgem, 2009). The current network price control (RIIO-ED1) runs for eight years from 2015-2023. Slow-track DNOs will be able to spend around £17bn over the period to renew, maintain and operate their networks (Ofgem, 2014). Therefore, taking the geometric average over all the 14 DNOs and price control sub-periods, the result from Model 1 is reported in Table 8.

[20] See Ofgem (2009) for a good summary of the price control periods.

[21] Price controls on the RECs' supply businesses only allowed price rises limited to no more than inflation during the period 1990/1991–1994/1995.

Table 8: *Distribution Price Control Review Period Model 1*

DPCR	EC	TC	PEC	SEC	TFPC
DPCR 0	0.961	1.038	0.985	0.975	0.998
DPCR 1/2	1.028	0.993	1.005	1.023	1.021
DPCR 3	1.019	1.034	1.014	1.005	1.053
DPCR 4	0.976	1.063	0.998	0.978	1.037
DPCR 5	1.025	0.921	1.004	1.022	0.945
RIIO-ED1	0.998	0.997	1.000	0.998	0.995
Whole period	**1.002**	**1.006**	**1.001**	**1.001**	**1.008**

The sector achieved the highest average productivity gains of 5.4% p.a. during the third distribution price control review period, which was higher than the average annual productivity growth for the whole period. This might be largely due to the operating expenditure efficiency target which was increased to 4.4% per annum in DPCR3 to account for distribution costs associated was the pattern of peak demands and 0.25% reduction in allowed revenue was imposed on some firms during the DPCR3 as a specific incentive to foster honesty in cost forecasts (Ofgem, 2009). This is followed by the fourth with average annual TPF growth of 3.3% as prices were allowed to increase in line with inflation (i.e. X = 0).

Beside the RPI-X regime, one of the notable incentives under the DPCR is the rolling retention mechanism designed for capex which created an incentive to obtain efficiencies in capex in the entire the duration of the control as opposed to the usual adjustment during the beginning next price control. The second distribution price control review periods experienced an average productivity growth rate of 2.1% p.a. No appreciable productivity growth was recorded in the first price control period. However, the average productivity declined by -5.5% in the fifth price control period occasioned by reduction in technical change. This result strongly suggests that the transition to the fifth price control had at least a short-term detrimental impact on productivity growth. Furthermore, this transition effect did not rapidly disappear. Productivity growth was also significantly dampened in the current price control period as the negative TFP growth from the preceding period affects the productivity change into the RIIO-ED1 period, which grew at -0.5% p.a (see Model 1 in Table 10). This finding reinforces the widely held notion that environmental targets and other non-monetised target incentives inherent in the current price control are reducing the measured TFP for the distribution network industries.

For brevity, we report only the TFP growth of the alternative models in Table 9 to show how the TFP growth of the baseline model is changing with the inclusion of quality and emission variables, and their implicit costs.

Table 9: Distribution Total Factor Productivity Change Models 1-7

Year	Model 1	Model 2	Model 3	Model 4	Model 5	Model 6	Model 7
1991/1992	1.064	1.064	1.050				
1992/1993	0.959	0.959	0.974				
1993/1994	0.925	0.925	0.927				
1994/1995	1.051	1.051	1.061				
1995/1996	1.105	1.105	1.107				
1996/1997	0.967	0.967	0.998				
1997/1998	1.025	1.025	1.051				
1998/1999	0.920	0.920	0.936				
1999/2000	1.099	1.099	1.078				
2000/2001	1.315	1.315	1.289				
2001/2002	1.070	1.070	1.157				
2002/2003	0.968	0.968	1.013				
2003/2004	1.029	1.029	0.995				
2004/2005	0.924	0.929	0.934				
2005/2006	1.349	1.397	1.119				
2006/2007	0.994	0.988	1.030				
2007/2008	0.915	0.910	0.887				
2008/2009	0.952	0.949	0.874				
2009/2010	1.028	1.048	1.139				
2010/2011	0.917	0.935	0.986				
2011/2012	0.945	0.920	0.933	0.916	0.929		
2012/2013	0.911	0.900	0.915	0.897	0.911		
2013/2014	0.920	0.915	0.914	0.904	0.903	0.922	
2014/2015	1.035	1.028	1.104	1.031	1.109	1.113	1.113
2015/2016	0.979	1.219	1.211	1.220	1.209	1.208	1.208
2016/2017	0.985	0.981	0.960	0.984	0.961	0.961	0.961
2017/2018	0.988	1.003	0.984	1.007	0.988	0.989	0.989
2018/2019	1.029	1.044	1.022	1.034	1.011	1.012	1.012
Mean	**1.008**	**1.018**	**1.019**	**0.995**	**0.998**	**1.030**	**1.053**

Model 1= unit distributed, customer number, network length, Capex and Opex
Model 2= unit distributed, customer number, network length, Capex and CML-adjusted Opex
Model 3= unit distributed, customer number, network length, Capex and CML-losses-adjusted Opex
Model 4= unit distributed, customer number, network length, peak demand, Capex and Opex
Model 5= unit distributed, customer number, network length, peak demand, Capex and CML-losses-adjusted Opex
Model 6= unit distributed, customer number, network length, peak demand, customer satisfaction, Capex and CML-losses-adjusted Opex
Model 7= unit distributed, customer number, network length, peak demand, customer satisfaction, Capex and CML-losses-emissions-adjusted Opex

In Model 2, we computed the rewards or penalties associated with CML targets in monetary term and adjust our Opex accordingly. This modification of Opex input substantially bolstered the overall sector TFP growth from 0.8% p.a. in Model 1 to TFP growth of 1.8% p.a. in Model 2. This result suggests that including the monetised CML incentive could enhance the sector's TFP growth as improvement in CML will be a cost reduction. However, Model 1 and Model 2 have the same TFP values in the earlier years because we only adjust from 2002/03 upwards when Ofgem started the customer interruption incentive scheme, so we did not value backward because the value is essentially zero. Also in Model 3, energy losses are monetised, and Opex is adjusted with the both the valuation of CML and energy losses. The finding reveals that the average annual TFP growth increased slightly by 0.1% from Model 2 to Model 3. The result shows that CML actually makes a difference and losses are not necessarily valuable in the security of supply (changes are of low value). Due to dearth of data for peak demand, we report a relative shorter sample period for Models 4-7. Although, the whole sample TFP growth cannot be compared to Models 1-3, they are useful for discussion on the impact of incentives on productivity growth for the price control periods.

The average TFP growth of each price control period for Models 1-7 for the distribution network productivity estimations is shown in Table 10. In Model 2, we incorporate CML incentives values into Opex to account for quality of service incentives and average TFP grows in the current regulatory regime at the rate of 5.8% p.a. as opposed to negative productivity growth of -0.5% in Model 1 during the same price control.

Table 10: *Distribution Price Control Review period Model 1-7*

DPCR	**Model 1**	**Model 2**	**Model 3**	**Model 4**	**Model 5**	**Model 6**	**Model 7**
DPCR 0	0.998	0.998	1.001				
DPCR 1/2	1.021	1.021	1.032				
DPCR 3	1.053	1.054	1.070				
DPCR 4	1.037	1.046	1.004				
DPCR 5	0.945	0.939	0.968	0.935*	0.959*	1.013*	1.113*
RIIO-ED1	0.995	1.058	1.040	1.057	1.038	1.038	1.038
Whole period	**1.008**	**1.018**	**1.019**	**0.995**	**0.998**	**1.030**	**1.053**

*These are not comparable with Models 1, 2 and 3, because they cover different periods.

With the exception of the baseline model, TFP growth improvement is observed across the remaining six models during the current price control regime. This result underscores the fact that stakeholder engagement comes at the expense of measured TFP and should be adequately and consistently adjusted for. Thus, it suggests that the monetised incentives for quality of service improves productivity performance significantly. Another interesting pattern from the standpoints of price control period is that productivity experienced the highest growth in the third price control period across the first three models which marks the period regulatory review of immediate price cut of 23.4% (Ofgem, 1999a). Looking at just RIIO-ED1 we see that including peak demand as an output increases productivity growth in the base model (Model 1 vs Model 4) but reduces it when CML and losses are valued (Model 3 vs Model 5). The further inclusion of customer satisfaction as an output and business carbon and SF6 does not change productivity much, if at all (Models 5, 6, 7). However, comparing Model 7 and Model 1, there is still a big productivity improvement +3.8% p.a. vs – 0.5% p.a. from including the wider range of variables Ofgem is now focussed on.

5. **Conclusion**

We analyse the productivity growth of the electricity distribution and transmission in GB and how changes in incentive mechanism have influenced the measured TFP using DEA. This method is attractive to the regulators as it shows the underlying data without stochastic element and does not require any imposition of a functional form. We consistently find productivity growth as measured by DEA over the whole period as being in the region of 1% p.a. over the up to 29 years that we have data for (1990/91 through to 2018/19). This performance is hardly surprising given that the productivity growth for the whole economy has also been slow and the headline figures for the price controls are to some extent consistent with this (30-40% maximum fall in the real price for electricity networks from 1990 to 2005[22], with rises following this).

Within the different price controls the period 2000-05 was a particularly strong growth period for electricity distribution, but growth has slowed after this, while the electricity transmission experienced peak TFP growth during the period 1993-1997. The lowest TFP growth was recorded in the price control period 2007-2013. This slowing is in line with the aggregate UK productivity figures reported by the ONS affected by the global financial crisis[23]. The slowing of productivity growth in energy networks has come as outputs have grown slowly, especially in terms of units of energy distributed and transmitted. By contrast other outputs such as network length and customer numbers have grown slowly. This creates challenging conditions for productivity growth in industries characterized by fixed costs and rising demands for increased network length and

[22] See Ofgem (2009).

[23] https://www.ons.gov.uk/economy/economicoutputandproductivity/productivitymeasures/articles/multifactorproductivityestimates/experimentalestimatesto2014

flexibility, due to rising population growth and large amounts of small scale electricity generation which increases system demands on both electricity transmission and distribution while reducing aggregate energy volumes.

The valuation of a range of quality and emissions variables in both electricity transmission and electricity distribution reveals some interesting insights on the impact of incentive regulation on network productivity. While the inclusion of the monetised quality variables makes a significant difference to the measured productivity growth, the monetised emissions variables do not make much difference. Although, the productivity gains arising from the improvements in quality of service are relatively small in transmission network but appear to be significantly larger in distribution network. Furthermore, we observe a very strong improvement in productivity growth in recent years, when a wider range of variables are available. This is quite notable in the current RIIO-ED1 price control period. Given the emphasis in RIIO on a wider range of outputs and incentives it would have been good to include more of these variables directly in our analysis, if data had been available for earlier years. However, it is still early days in terms of the new measures that have been incentivized, especially on customer satisfaction and promotion of distributed generation. The sorts of measurement issues around whole economy productivity identified by Coyle (2015) could therefore be significant.

Overall, our study suggests that incentive regulation can be effective in achieving its intended objectives of reducing the wider societal impacts of the electricity sector and improving quality of service. However, how the regulators implement incentive schemes and what they really incentivize are important. Measurement of productivity growth should also reflect what regulatory incentives are targeting. This is because we want to measure how worthwhile such targets are and because we do not want to miss genuine increases in productivity growth which conventional measures of productivity are missing.

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Appendix I

Descriptive Statistics

Table A1: Descriptive Statistics for Electricity Transmission Network

Variable	Unit	Mean	Std.Dev	Min	Max
Energy transmitted	TWh	310.60	16.72	280.00	341.87
Network length	Km	23650.23	446.81	22853.85	24155.39
Peak demand	GW	55.41	3.64	47.34	60.84
Capex	£M 2012/13 price	702.87	367.59	272.54	1595.78
Opex	£M 2012/13 price	519.35	257.47	241.71	1112.91
VoLL adjusted Opex	£M 2012/13 price	533.21	260.50	253.12	1117.78
VoLL and emission adjusted Opex	£M 2012/13 price	537.03	257.32	253.12	1117.78
System non-availability	Km	1048.74	242.19	708.58	1500.48

Table A2: Descriptive Statistics for Electricity Distribution Network

Variable	Unit	Mean	Std.Dev	Min	Max
Energy delivered	GWh	21128.15	7180.10	7117.00	37513.00
Customers number	Number	1983580.22	694043.84	590000.00	3638189.00
Network length	Km	55185.67	15956.06	29432.00	98070.96
Peak demand	MVA	3895.80	1420.43	1417.00	6966.00
Capex	£M 2012/13 price	95.28	35.44	36.04	246.78
Opex	£M 2012/13 price	153.06	103.04	17.99	481.61
CML adjusted Opex	£M 2012/13 price	145.36	106.92	17.99	481.61
CML and losses adjusted Opex	£M 2012/13 price	196.43	114.25	41.32	550.88
CML, losses and emission adjusted Opex	£M 2012/13 price	142.64	48.03	45.79	281.21
Customer satisfaction	Number	17925650.90	6087659	6266224	32059321.27

Appendix II

We deflate capital expenditure using gross fixed capital formation price deflator as capital index. The ONS variable code for the gross fixed capital formation price deflator is CDID:YBFU. We use wage index as proxy to deflate operating expenditure. Two measures of wage index are reported by the ONS; the Average Weekly Earnings (AWE) statistics and the Average Earnings Index (AEI). We consider the indices for the whole economy with the ONS variable code CDID: K54U for the AWE and the code CDID: LNMQ for the AEI. The indices are reported monthly and we construct the annual series following the Ofgem annual regulatory fiscal year end in March for both capital index and wage index. However, the AEI has been discontinued and replaced with the AWE index as the lead measure of changes in earnings, especially for measuring the inflationary pressure emerging from the labour market by the Bank of England and HM Treasury (ONS, 2017)[24]. Therefore, we assume that the AWE is more accurate and we use it as far it goes, and apply the older version where applicable. For example, the AWE is available from 2000 and this is spliced with the AEI from 1990-1999 to fully cover our sample period.

Appendix III

Monetisation of Quality and Emissions Variables used in the DEA Models

1. CML incentive value

Table A3 reports the DNO targets interruption per and incentive rate for each minute of reduction during the current regulatory period, RIIO-ED1, 2015/16-2022/23. However, Ofgem introduced the incentive scheme on 1 April 2002. The scheme penalizes or rewards DNOs subject to their performance against their targets for customer minutes lost.

[24]See the link for details; https://www.ons.gov.uk/employmentandlabourmarket/peopleinwork/earningsandworkinghours/methodologies/averageweeklyearningsqmi

Table A3: RIIO-ED1 targets interruptions and incentive rates

TBUt – Duration of unplanned customer interruptions term targets

	Regulatory Year							
Licensee	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**
ENWL	40.6	39.8	39.1	38.3	37.6	36.9	36.2	35.5
NPgN	54.8	53.7	52.7	51.7	50.7	49.7	48.8	47.9
NPgY	57.5	56.3	55.2	54.1	53.0	52.0	50.9	49.9
LPN	38.8	38.1	37.5	36.8	36.2	35.6	35.0	34.4
SPN	45.5	44.5	43.5	42.6	41.6	40.7	39.8	39.0
EPN	48.0	47.0	45.9	44.9	43.9	43.0	42.1	41.2
SPD	42.2	41.3	40.5	39.7	38.9	38.1	37.4	36.7
SPMW	35.1	34.3	33.5	32.8	32.1	31.3	30.6	30.0
SSEH	53.9	52.8	51.6	50.5	49.2	47.7	46.6	45.6
SSES	48.1	47.1	46.2	45.3	44.4	43.5	42.6	41.8

Example:

Target interruptions per year

IRBt – Duration of customer interruptions term incentive rate (£m per CML, in 2012/13 prices)

	Regulatory Year							
Licensee	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**
ENWL	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89
NPgN	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
NPgY	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
LPN	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
SPN	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
EPN	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34
SPD	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
SPMW	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56
SSEH	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
SSES	1.12	1.12	1.12	1.12	1.12	1.12	1.12	1.12

Incentive rate for

each minute of reduction

Source: Ofgem (2014, p.12)[25]

To evaluate the trend in CML target performance, we use 2002/03 as a base year, being the first year the incentive scheme was introduced. The valuation starts from 2002/03 as no adjustment was made in the earlier years. CML incentive value is calculated by subtracting target interruption per year for each DNO from the base year target for each DNO, and then multiply it by the monetary incentive rate expressed in £m per CML. For example, Table A3-TBUt reports the CML target for SSES in 2015/16 as 48.1 and the corresponding incentive rate on Table A3-IRBt for SSEs is £1.12m. The incentive rate is adjusted using wage index to obtain an adjusted incentive value of £1.13m expressed in 2012/2013 prices. If the CML target for SSES in 2002/03 is 100.58, then the CML incentive value for SSES in 2015/16 can be calculated as follows;

CML incentive value = (Base year CML targets – yearly CML targets) × adjusted incentive rate

$$= (100.58-48.1) \times 1.13$$

$$= £59.30m$$

[25] See the link for details; https://www.ofgem.gov.uk/sites/default/files/docs/2014/12/riio-ed1_final_determinations_detailed_figures_by_company_-_updated_front_cover_0.pdf

2. Carbon emission cost

Emission variables data are recently being reported by Ofgem in the current price control period, RIIO-1, starting from 2013/2014, and their valuation only covers this period for both transmission and distribution networks. Therefore, we compute the cost of carbon emission from as follows;

Carbon emission cost = Business Carbon Footprint (tCO2e) × annual social price of carbon[26] *(in 2012/13 prices)*

3. SF6 cost

The monetisation of SF6 emission cost involves two steps. First, we converted SF6 emission measured in kilogram (kg) to tCO2e using SF6 global warming content. The value of the global warming potential of SF6 is 22,800[27]. Thus, starting from 2013/2014, the tCO_2 equivalent of 62kg of SF6 is calculated as follows:

$$
\begin{aligned}
SF6\ (tCO2e) &= \text{Mass (in tonnes) of } SF6 \times \text{global warming potential of } SF6 \\
&= (62/1{,}000) \times 22{,}800 \\
&= 1413.6\ tCO_2e
\end{aligned}
$$

Second, we multiplied tCO_2 equivalent value of SF6 by social price of carbon. According to the UK Department of Energy and Climate Change (DECC), the value of central traded carbon price in 2015 adjusted by wage index is 6.51 in 2012/2013 £/tCO_2e.

$$
\begin{aligned}
SF6 \text{ emission cost} &= SF6\ (tCO2e) \times \text{annual social price of carbon } (£/CO2) \text{ (in 2012/13 prices)} \\
&= 1413.6 \times 6.45 \\
&= £9{,}202.53
\end{aligned}
$$

[26] See transmission and distribution data sections for details on Business Carbon Footprint and social price of carbon.

[27] The formula for calculating CO2 equivalent and global warming potential value for SF6 and other fluorinated greenhouse gases are reported in this link: https://www.gov.uk/guidance/calculate-the-carbon-dioxide-equivalent-quantity-of-an-f-gas

4. Value of load lost (VoLL)

For the Calculation of VoLL, we use £17,000/MWh (2012/13 prices), being the consumers' willingness to accept (WTA) payment for loss of load on weekday, winter evening peak. We then calculate VoLL cost by multiplying the WTA value by energy not supplied.

$$VoLL = \ \ energy\ not\ supplied\ (MWh) \times £17000/MWh$$

5. Cost of energy losses

The valuation of energy losses is obtained by multiplying distribution energy losses in MWh by average annual UK wholesale electricity prices expressed in £/MWh 2012/2013 prices, covering 1990/1991 to 2018/19. The wholesale electricity price is based on the UK annual spot average price series (UKPX Reference Price Data) over the sample period. We adjust wholesale electricity prices following annual regulatory fiscal year end in March and deflate it using wage index.

$$Cost\ of\ energy\ losses = energy\ losses\ (MWh) \times wholesale\ electricity\ prices(\text{£/MWh})$$