Half-Hourly Regional Electricity Price Modelling for Commercial End Users in the UK

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ABSTRACT

This paper details a methodology to model half-hourly electricity price profiles for the UK commercial end-users; thus allowing consumers to visualize and calculate more accurately the cost of the electricity they consume. The methodology consists in a bottom-up model that defines individually all the tariff components of the bill and then aggregates them to quantify the cost of a kWh across the day. In this work ,'representative day' electricity price curves for different months, day types, voltage levels connections, and regions in the UK from 2015 up to 2020 are presented. Outputs from this work can inform companies to better understand their energy costs and accurately perform economic assessments of investments in schemes that reduce emissions and aim towards reaching net zero energy buildings. In addition, the disaggregated structure of the model allows specific analysis of individual components thus highlighting which elements carry a larger weight on costs across the year; such as network charges originated from distribution and transmission system operators. Due to its multi-variable dependency, the model produces more than 5,000 representative day curves. The results show that those commercial buildings connected to Low Voltage (LV) in North Wales and Merseyside, Northern Scotland, the South West and South Wales face the highest average electricity prices, whereas consumers connected to HV in London and Yorkshire have the cheapest electricity in the UK.

INTRODUCTION

The UK has one of the most expensive electricity bills in Europe for non-domestic consumers. Businesses across Grear Britain paid in 2014 almost three times what they did in 2004, suffering the highest rise among the IEA nations in this period (DECC 2015). Increasing prices and corporate social responsibility are encouraging companies to invest in on-site generation capacity and energy efficiency measures to reduce their electricity costs and decarbonize the operation of their buildings. The multiple options available to accomplish this decarbonization and the complexity and multi-variable character of electricity prices increase the difficulty to optimize investmet decisions.

In addition, literature on real-time electricity price modelling does not tackle this issue directly and it is mainly focussed on forecasting the wholesale electricity price or on assessing the effectiveness of dynamic price tariffs. In Weron (2014) they produced an overview of the available solutions to forecast electricity wholesale prices, explaining methodologies from fundamental methods to computational intelligence techniques. In this same review, they also explore the variables that affect the electricity price, such as fuel prices and weather. Regarding dynamic pricing, most of the literature studies the effectiveness of the implementation of Time of Use tariffs to residential consumers to encourage demand side response (Kim and Giannakis 2014).

Nonetheless, commercial consumers in the UK are not billed based on standard tariffs and, as they are metered

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half-hourly, they interact with the wholesale market directly. However, even if the price of the commodity itself is the biggest components of the electricity bill, this part does not cover the total electricity costs of businesses. In fact, the share of the energy component is decreasing and the increase in electricity prices is currently mainly driven by non-contestable components such as network charges and levies to finance renewable capacity (ACER 2016). These components are often easier to predict and therefore also easier to reduce after an accurate characterization.

Based on this context, there is a clear need for a methodology to characterise and aggregate all the components of commercial electricity bills to inform energy management teams of companies in the UK. Accordingly, this paper focuses on expanding a bottom-up model that generates half-hourly electricity price curves to allow consumers to understand their electricity expenditures over the time for different regions in the UK (Acha and Bustos 2015). Northern Ireland has been omitted from this study as its electricity bill structure is not the same as the one in mainland Britain.

This paper is structured into four sections. The current section exposes an introduction with some background, and the purpose of the paper. The second section shows the methodology, briefly explaining the different components that are identified, classified and modelled, and finally explaining the equations used for their characterization. The third section provides the results with some examples of the curves obtained directly from the model and an analysis to compare how average prices change with the variables included in the model. The final section lists concluding remarks.

METHODOLOGY

This paper describes a methodology to obtain half-hourly electricity price curves for different voltage level connections across the UK and every month up to March 2020. Firstly, each component of commercial electricity bills is identified and classified depending on its spatial and temporal dependence. Then, they are modelled independently to finally aggregate them all and obtain the half-hourly electricity price. Each component is defined by the following variables: half-hour (in the UK power market, electricity price is defined each 30 minutes and therefore, these 30 minute periods are called settlement period), natural months, day types (weekdays – WD, and weekend days – WE), UK financial years (April to March) from 2015-16 to 2019-20 and three connection voltage level (Low Voltage – LV, Low voltage substation – LV Sub, and High voltage – HV). With these variables the model provides a set of 5040 representative day curves with 48 half-hourly values of the price of electricity. This way, decision makers can use them to, firstly, understand their electricity costs and, secondly, assess the financial viability of energy projects.

Electricity bill

Apart from the energy, consumers pay for using the electricity network, for the energy lost when transporting the energy, to the system operator for the balancing of the grid every second and to the regulator that manages the subsidies to renewables. For this paper, 14 elements define the electricity price in the bottom-up model.

- The *commodity* includes the cost of purchasing energy in the wholesale market, usually via bilateral contracts for baseload and peakload clips with adjustments to the final consumption in the spot market.
- In these bilateral contracts final consumption is scaled up to account for the energy lost when transporting the electricity through the transmission (*transmission losses*) and distribution (*distribution losses*) networks.
- The Distribution Network Use of System charges (DUoS) recover the costs incurred by the distribution network operators (DNO) for owning and operating the distribution network. There are three different mechanisms: *DUoS commodity*, *DUoS capacity* and *DUoS administrative*. DUoS commodity is charged based on the energy consumed and the time of consumption, DUoS capacity is a daily charge that depends on the maximum imported capacity contracted by the customer. DUoS administrative is a fixed daily charge to cover the administration costs of keeping the customer connected.
- The *Transmission Network Use of System charges (TNUoS)* recover the cost incurred by the transmission grid

owners for installing and maintaining the transmission system. Consumers are charged based on their consumption during the three half hours of highest demand of the year, called triad periods. These periods have always happened between 5 and 6.30pm of weekdays between November and February (NG 2015).

- In addition, the Transmission System Operator (TSO – National Grid – NG) is also responsible for balancing the grid incurring in additional costs to contract reserves or frequency response services. This cost is recovered throught the *Balancing Services Use of System charges (BSUoS)*, computed half-hourly.
- Finally, consumers pay for the different schemes to subsidize renewable energy sources: the *Renewable Obligation (RO)* for large scale projects (which is being replaced by the *Contract for Differences – CfD*) and the *Feed in Tariffs (FiT)* for small scale projects. In addition, the UK introduced the *Climate Change Levy (CCL)*, an environmental tax to incentivize large consumers not covered by the EUETS to reduce their energy use and associated emissions and the *Capacity Mechanism (CM)* to recover the cost of running an annual capacity auction to secure energy supply and incentivise the investment in new capacity and demand side response.

Table 1 shows a classification of the components depending on their temporal dependency. Each component is classified into one of these four groups: half-hourly settled, deterministic, non-kWh based and constant. The methodology followed to model is similar for all the components of each group. Depending on their spatial dependence, the methodology is applied either for the entire UK or for each of the 14 Distribution Network Operaor areas.

Table 1. Components of the Electricity Bill

Type	Description	Components (parameter)	Data Source
Half-Hourly settled components (c1)	They change every half hour depending on the real-time state of the system.	Commodity (Market Index Price) BSUoS (BSUoS Tariff) Transmission losses (TLM)	Elexon NG Elexon
Deterministic components (c2)	Different tariffs are applied during different periods of the day according to a defined profile. Both the tariffs and periods are defined yearly	Capacity Mechanism (CM tariff) DUoS com (Red/Amber/Green tariffs) Distribution losses (LLF)	EMR sl DNOs DNOs
Non-kWh based components	The amount billed for these components does not depend on the energy consumed.	DUoS capacity (Capacity tariff) DUoS admin (Admin tariff) TNUoS (TNUoS tariff)	DNOs DNOs NG
Constant components	It is a special type of deterministic components which do not change for the entire year and components are equally charged to every energy unit consumed.	Renewable Obligation (RO), Feed in Tariff (FiT), Climate Change Levy (CCL), AAHEDC, Contract for Differences (CfD)	NRA (Ofgem) NG LCCC

Half-hourly settled components

For these components, data for the last two financial years (2014-15 and 2015-16 April to March) is processed to obtain a 'typical day profile' for each month and day type (24 data sets). After classifying the historical values into these groups, daily average price profiles are obtained by calculating the average of each of the 48 settlement periods of the day as shown in the Equation 1. Resulting average profiles tend to be smoother than actual daily profiles so, using the daily Root Mean Square Error, the day with the most similar profile to the average is selected as the representative day (Equation 2). It is important to notice that the result of Equation 2 is a 48 element array obtained directly from the data set, which best represents the average of the whole period.

$$\overline{c1}_{m\,w\,s} = \frac{\sum_{i=1}^{n} Dc1_{m\,w\,s_i}}{n} \tag{1}$$

$$\widehat{c1}_{m\,w} = min_i \left(\sqrt{\frac{1}{48} \cdot \sum_{s=1}^{48} \left(Dc1_{m\,w\,s_i} - \overline{c1}_{m\,w\,s} \right)^2} \right) \quad (2)$$

This way 24 profiles are defined for each component. To obtain future profiles of these components, inputs from other analysis (such as DECC 2016) are used to obtain one single coefficient (f_y), which represents an index of the average unit price of each component in the year in the future compared with the initial year. This way, Equation 3 defines the half-hourly value of *commodity*, *BSUoS* and *TLM* for every year. In addition, as the wholesale price is the biggest component and it also depends on the procurement strategy of the specific business, the Procurement Strategy coefficient is introduced to scale the representative day profiles for the initial year of this component. The Procurement Strategy coefficient is the ratio between the average price of the electricity purchased for the initial year and the average wholesale price that the consumer would pay if all the energy was purchased in the spot market.

$$c1_{m,w,s,y} = f_y \cdot \widehat{c1}_{m,w,s} \quad (3)$$

Deterministic components

Equation 4 defines the general formulation for deterministic components. Whereas the capacity mechanism is only applied between 4pm and 7pm of winter (November to February) weekdays in the entire UK, *DUoS commodity* and *LLF* are defined for each DNO and therefore, change from one DNO area to another. The information for these components is collected from the documents Schedule of Charges and Other tables published yearly by each DNO (UKPN (2016), for example, defines the tariffs and periods for the year 2016-17 in London).

$$c2_{m,w,DNOa,con,y,s} = \begin{cases} v1_{m,w,DNOa,con,y} \; if \; s \in \; p1_{m,w,DNOa,y} \\ \quad \cdots \\ vn_{m,w,DNOa,con,y} \; if \; s \in \; pn_{m,w,DNOa,y} \end{cases} \quad (4)$$

Non-kWh based components

These components are billed based on tariffs not proportional to the energy consumed. To include them in this analysis, these tariffs are transformed into kWh based components using average demand information. This transformation makes the results of the model business specific, as the demand profiles of buildings are highly dependent on the activity that they hold.

DUoS capacity tariffs are published in £/KVA/day and it varies for different voltage levels, DNO areas and years. To spread this charge over every kWh consumed, the Annual Utilisation Factor (UF) is introduced. The UF is defined by Equation 5 as the ratio between the total annual consumption of a building and the contracted maximum import capacity. Using this factor the tariff is transformed into a kWh based charge using the Equation 6.

$$UF = \frac{Annual\ Consumption\ [kWh/yr]}{Capacity\ [KVA]} \quad (5)$$

$$DUoS\ cap_{DNOa,con,y} = \frac{vDUoS\ cap_{DNOa,con,y} \left[\frac{p}{kVA\ day}\right] 365 \left[\frac{days}{yr}\right]}{UF \left[\frac{kWh}{yr\ KVA}\right]} \quad (6)$$

The *DUoS administrative* charge is a standard daily charge so it is not normalised to the capacity or any other indicator of the size of the consumer. Therefore, the factor to transform this tariff into a kWh based tariff is the average daily consumption. However, the variation of this factor is very big from one consumer to another and its relevance in the final bill is very small. For these reasons, this component is neglected and out of the scope of the model.

TNUoS are charged based on tariffs published by NG in £/kW and the average consumption during the triad periods. Tariffs, which are different for each DNO area, are taken from NG (2016). Following a similar methodology as for the *DUoS capacity*, the objective is to spread the *TNUoS* charge over an energy consumption; in this case, the energy consumed when a triad period is likely to happen. The triad consumption of a site depends on its activity and its size. For this reason, the contracted maximum import capacity is considered as the parameter to capture the effect of the size. The parameter Triad Intensity (TI) is defined as the ratio between the historical triad consumption and the contracted capacity (Equation 7).

$$\mathrm{T}I = \frac{Triad\ measurements\ [kW]}{Capacity\ [KVA]} \tag{7}$$

In addition, a factor similar to the UF is used to calculate the energy demand during the triad period per KVA capacity contracted. This new factor is defined as Triad Utilisation Factor (TUF) and it is firstly calculated considering that the consumption is the same as the triad consumption for any moment when a triad can happen (Equation 8). However, if there are data available, this value can be substituted by the historical consumption of winter weekdays between 5 and 6.30 pm. With these two factors, the tariffs in £/kW are transformed into p/kWh with the Equation 9.

$$\mathrm{T}UF = \mathrm{TI} \cdot 120 \cdot \frac{5}{7} \frac{WD[Nov,Feb]}{yr} \cdot 1.5 \frac{hours}{day} \tag{8}$$

$$v2TNUoS_{DNOa,y} = vTNUoS_{DNOa,y} \left[\frac{p}{kW}\right] \cdot \frac{TI\left[\frac{kW}{kVA}\right]}{TUF\left[\frac{kWh}{kVA}\right]} \tag{9}$$

On the other hand, the possibility of a Triad period to happen in any settlement period between 5:00 and 6:30 between November and February is not the same. To capture this temporal variation on the *TNUoS* charge, the triad periods of the last five years are analysed (NG 2015). From this analysis, weighting factors for each month and settlement period are calculated to allocate *TNUoS* charge proportionally to the possibility of the triad period to happen. Table 2 shows these weighting factors. Finally, the *TNUoS* half-hourly cost is calculated with the Equation 10. It is important to notice that this transformation and the unpredictable nature of the triad periods introduce an element of uncertainty to the model, especially when the results are used to optimize the operation of on-site generation. In any case, the price spikes during winter weekdays resulted from this methodology provide a price signal to consider *TNUoS* even if they do not reflect the cost of electricity as triad periods only happen three times a year.

Table 2. TNUoS Weighting Factors (TimeFac [-])

Settlement Period	November	December	January	February	Other months
5-5.30 pm	1.92	2.56	3.20	1.92	0
5.30-6 pm	0.32	0.43	0.53	0.32	0
6-6.30 pm	0.16	0.21	0.27	0.16	0
Other hours	0	0	0	0	0

$$TNUoS_{DNOa,y,m,s,w} = v2TNUoS_{DNOa,y} \cdot TimeFac_{m,s,w} \tag{10}$$

Constant components

They are constant throughout the entire year and applied to any energy unit consumed so they are modelled as a constant tariff charged to any kWh consumed and they do not change neither with the location nor with the time. The tariff is yearly defined.

Real time electricity price aggregation

Before aggregating the components, the measurement point for the billing of each component is defined. Each component can be billed based on three different measurement points. Some components are billed from transmission level and include transmission and distribution losses. Others are billed from the interface between transmission and distribution systems, called Grid Supply Point (GSP), and they only include the distribution losses. Finally, there are components billed based on the final demand, called Meter Supply Point (MSP), which does not include any losses. *Energy* and *BSUoS* are billed based on the measurement in the transmission level, *TNUoS* at the GSP and the rest at the MSP. Equation 11 includes defines the methodology to aggregate all the components.

$$p_{s,w,m,y,DNOa,con} = e_{s,w,m,y} \cdot LLF_{DNOa,con,s,w,m,y} \cdot TLM_{s,w,m,y} + BSUoS_{s,w,m,y} \cdot LLF_{DNOa,con,s,w,m,y} \cdot TLM_{s,w,m,y} + DUoScom_{DNOa,con,s,w,m,y} + DUoScap_{DNOa,con,y} + TNUoS_{DNOa,s,w,m,y} \cdot LLF_{DNOa,con,s,w,m,y} + AAHEDC_y + RO_y + CCL_y + FiT_y + CfD_y + CM_{s,w,m,y} \tag{11}$$

RESULTS

This section provides some examples of the half-hourly curves obtained from the model using a UF of 3735 kWh/year/KVA and a TI of 54%. In addition, the result of further postprocessing of these curves is shown to demonstrate the potential of this tool. Figure 1 shows the regional differences in the electricity price profile in a summer month (June) and a winter month (January). It can be observed that the shape and scale of these curves is greatly affected by *TNUoS* and *DUoS*. *TNUoS* produce the big price spike on winter weekdays for every region, when electricity price rises over £1 per kWh. On the other hand, for the rest of the year, the different tariffs and periods of *DUoS* dominate the shape of the profile of each region. It is important to notice that this difference is also present during winter weekdays but the scale of the transmission charges makes it impossible to appreciate in the graph. On average, winter months were 15% more expensive in the year 2015-16 and this difference is expected to increase up to 20% in 2019-20 (mainly driven by the increasing relevance of the capacity mechanism). The months when the electricity is most expensive are January, December and November and it is the cheapest during June, March and July. Regarding the day type, electricity during weekdays is between 30% and 44% more expensive than during the weekends. With these information, energy teams in commercial buildings can optimize the operation of on-site generation or better plan the maintenance periods of energy schemes, to make sure that electricity imports from the grid are minimum when electricity prices are high. In addition, this curves are vital to effectively assess Demand Side Management and storage projects and estimate their revenues.

Figure 1. Half hourly electricity price curves for High Voltage connection for weekdays during financial year 2016-17 in June (Left) and January (right) for the regions of the South East, Northern Scotland and London.

When the effect of the connection level is disaggregated, the consumers connected to LV present the highest prices followed by LV Substation and those connected to HV have the cheapest electricity prices. Figure 2 shows on the left the evolution of the annual average electricity price for the three connection types, displaying the value for their average. Every year, LV has prices between 7.3% and 7.6% higher than HV and LV Sub between 3.7% and 4% higher than HV. Figure 2 shows maps with the average annual electricity price across the UK. The scale has maintained for the two maps to allow comparison between them.

The four most expensive regions are North Wales & Mersey, Northern Scotland, South Wales and the South West. On the other end, London, Yorkshire, Eastern England and Northern England are the regions with the lowest average electricity prices. The difference between the most expensive and the cheapest varies between 9.4% and 11.2% in the five years analysed. The greatest price increase is forecasted to happen in Southern England (14.9%) and the lowest Northern Scotland (9.6%). With this information, companies that own buildings across the entire UK can identify those buildings with highest average electricity prices and focus on reduce their energy demand first. This way, they will recover the investments in energy schemes earlier and will move towards sustainability more cost-effectively.

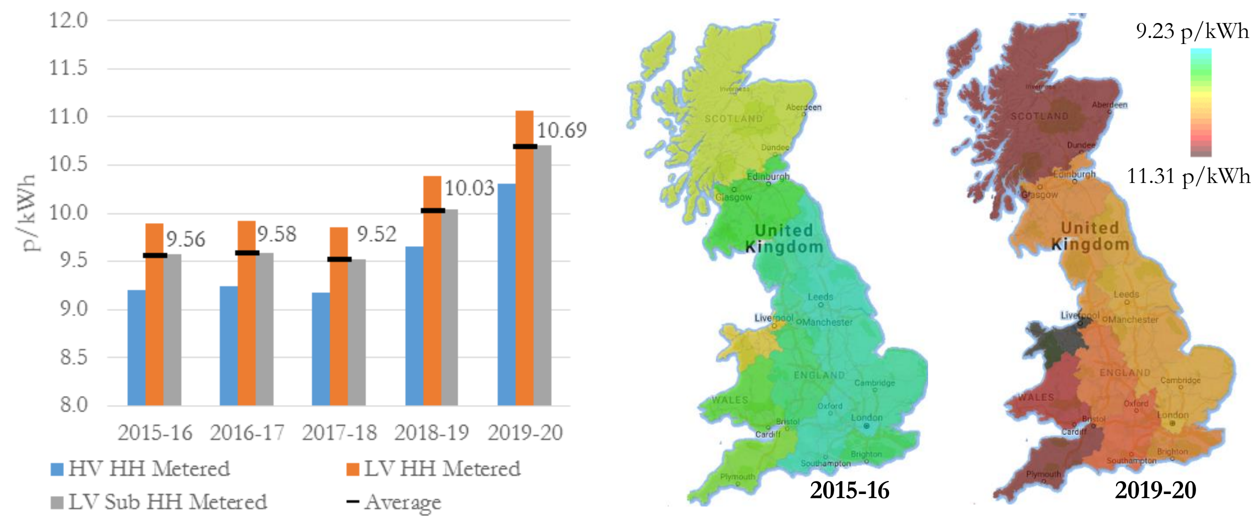

Figure 2. (Left) Average annual electricity price for different connection voltage levels. (Right) Annual average electricity prices across the UK for 2015-16 and 2019-20 [1].

CONCLUSIONS

This work has showcased a novel approach to quantify the final electricity costs of commercial customers across the UK at half-hourly intervals. Results indicate that electricity prices for customers vary across the country due to intraday and seasonal variability and voltage connection level. Since the findings of thia analysis suggest average electricity prices are set to rise, this tendency should stimulate investment in energy efficiency projects and on-site generation in order to reduce the electricity bills of businesses. This new modelling methodology provides a holistic view of how each tariff influences what end users pay for electricity. By employing such methods customers can easily visualize how electricity price changes with time and across the UK. Therefore, businesses can improve their understanding on their energy costs and adapt their consumption strategies to minimize electricity bills. In addition, the granularity of the results can inform energy management teams when optimizing energy investments; such as building retrofits, energy reduction measures, or installing low carbon technologies. Results of this model prove that not only the activity and the demand of a building are important to assess profitability of energy projects, but also its location and connection voltage level. In particular, properties connected to Low Voltage in Northern Scotland and North Wales & Merseyside by being the most expensive ones should offer the best return on investment for energy saving projects.

[1] *These regional land policies came from the Geocaching.com Public Wiki and are licensed under a Creative Commons Attribution-NonCommercial-No-Derivatives 4.0 International License.*

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NOMENCLATURE

Variables

con =Connection type
DNOa = DNO area
m = natural month
s = settlement period
w = day type
y = year

Components

AAHEDC = Assistance for Areas with High Electricity Distribution Costs
BSUoS = Balance Services Use of System
c1 = Half hourly settled components
c2 = Deterministic components
CCL = Climate Change Levy
CfD = Contract for Difference
CM = Capacity Mechanism
DUoS = Distribution Use of System
e = Commodity
FiT = Feed in Tariff
LLF= Line Loss Factor
p = Aggregated electricity price
RO = Renewable Obligation
TLM = Transmission Loss Multiplier
TNUoS = Transmission Network Use of System

Parameters

fy = Annual scaling factor
i = Data day
n = Number of data days for each group
p1 = Period 1 for deterministic components
TI = Triad Intensity factor
TUF = Triad Utilization Factor
UF = Annual Utilization Factor
v = Tariff for a component

Other Acronyms

DNO = Distribution Network Operator
HV = High Voltage
LV = Low Voltage
LV Sub = Low Voltage Substation
NG = National Grid
TSO = Transmission System Operator
WD = Weekday
WE = Weekend Day

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