ELECTRICITY DEMAND, GENERATION EFFICIENCY AND COSTS IN KENYA

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29th October 2020

DECLARATION

This thesis is my original work and has not been presented for a degree in any other university.

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DEDICATION

To God almighty and to my family for all the support.

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LIST OF ACRONYMS AND ABBREVIATIONS

EAP&L	East Africa Power and Lighting Company
ADF	Augmented Dick Fuller
ARDL	Autoregressive distributed lag
CRS	Constant returns to scale
Cumecs	Cubic metre per second
CUSUM	Cumulative sum
DEA	Data envelope analysis
DISCO	Distribution Company
DMU	Decision making unit
ERB	Electricity Regulatory Board
ERC	Energy Regulatory Commission
FERFA	Foreign exchange rate fluctuations adjustment
FiT	Feed in Tariffs
FOCA	Fuel oil cost adjustment
GDC	Geothermal Development Company
GDP	Gross domestic product
GWh	Giga watt hour
IPP	Independent Power Producer
KenGen	Kenya Electricity Generating Company
KETRACO	Kenya Electricity Transmission Company
KIPPRA	Kenya Institute for Public Policy Research and Analysis
KPLC	Kenya Power and Lighting Company

KPSS	Kwiatkowski–Phillips–Schmidt–Shin
KNBS	Kenya National Bureau of Statistics
KSh	Kenya Shilling
Ktoe	Kilotonne of oil equivalent
kWh	Kilo watt hour
kV	Kilo Volt
kVA	Kilo Volt Amp
MOE	Ministry of Energy
MVA	Mega Volt Amp
MW	Mega watt
MWh	Megawatt hour
PP	Philips Perron
PPA	Power Purchase Agreement
REA	Rural Electrification Authority
SAIDI	System average interruption duration index
SFA	Stochastic frontier analysis
TFP	Total factor productivity
VRS	Variable returns to scale

ABSTRACT

The government of Kenya has been making commendable efforts towards providing affordable energy to its citizens. However, the cost of electricity has been increasing despite reform programmes aimed at reducing costs. This thesis examined some of the critical considerations in the determination of electricity tariffs. Three essays were undertaken. The first essay examined the demand for electricity and made forecasts with a view to ascertain if the official demand forecast was realistic. Using autoregressive distributed lag (ARDL) model and time series data from 1985-2016 sourced from various sources including Kenya Power and Lighting Company (KPLC) annual reports, Kenya National Bureau of Statistics Economic Surveys and Statistical Abstracts, World Bank statistics and Kenya Electricity Generating Company hydro data. The findings showed that the official demand forecast was overstated and encouraged overinvestment in the generation of electricity. Overinvestment pushes the costs of electricity supply increasing the tariffs. Commercial and industrial consumers were projected to continue being the largest consumers of electricity. The finding indicated the need for the Ministry of Energy to revisit the planned investments and prioritize projects that address supply side constraints. The potential increase in costs arising from overinvestment can be prevented by signing take and pay power purchase agreements instead of take or pay removing the current protection offered to the generators. The second essay investigated the efficiency of thermal power plants. Using stochastic frontier analysis and data for 27 thermal generating power plants for the period July 2015 to December 2017 sourced from the power plants and the Energy Regulatory Commission, the study found the plants to be inefficient. Fuel was found to be a significant factor of production. Grid connected plants were found to be more efficient than isolated power plants. The inefficiency largely stemmed from age and ownership. The Malmquist data envelope analysis, however, found improved performance over the study period. To increase efficiency in generation, there is need for the regulator to revisit the methodology used for fuel oil cost adjustments. Ministry of Energy should also encourage private

investments in generation and extend the grid to the isolated areas. The third essay sought to explain the electricity tariffs by exploring the drivers of KPLC tariffs. Since the tariffs are set using the cost of service regulation, KPLC cost data for the period 1986-2016 was used for the analysis. Average cost function of KPLC was estimated using ARDL model. The findings indicated output, system losses, system load factor and price of labour to be the drivers of average costs. System losses and price of labour were found to be increasing the average cost. The finding indicated the need for the regulator to set stringent loss reduction targets for KPLC. The Ministry of Energy should facilitate competition in the commercial retailing functions of KPLC as proposed in the Energy Act, 2019 to reduce the commercial losses associated with theft, corruption, billing and metering errors. The regulator should also tie allowed staff costs to improved customer service standards as a way of managing the cost of labour. KPLC was found to be enjoying economies of scale and economies of output density, this indicates the need for the electricity market to retain transmission and distribution of power as a natural monopoly. The Ministry of Energy should also continue with interventions and incentives that increase the system load factor such as time of use tariffs. Encouraging industrial parks and special economic zones through special tariffs could also increase the energy consumption and load factor.

CHAPTER 1

INTRODUCTION

1.0. Background to the study

The Republic of Kenya has been committed to providing affordable quality energy to all Kenyans to effect social transformation and economic development (Republic of Kenya, 2004). However, this desire has not been fully realized. Although the government has made tremendous achievement in scaling up connectivity to electricity with the access rate rising from 32% in 2014 to 75% in 2018 (Republic of Kenya, 2018a), there is the twin challenge of providing access to electricity to the remaining 25% of the population mainly in rural areas and reducing the ever rising electricity prices. One of the challenges cited by government in dealing with electricity prices is the potential demand risk. This is arising from too much planned generation capacity that translates into excess supply and underutilization of power plants increasing electricity costs (Republic of Kenya, 2018b).

In determining electricity prices, the Energy Regulatory Commission (ERC) relies on the total future costs of supply as well as demand to come up with cost-reflective tariffs. The cost of supply includes the expenses from generation, transmission, distribution, metering and billing (Electricity Regulatory Board, 2005). The projected demand affects electricity prices in two ways. First, the price per unit is based on the projected energy sales. The higher the sales compared to the total costs of supply the lower would be the price and conversely. Second, all investment requirements are dependent on future electricity demand (Electricity Regulatory Board, 2005). An over projection of demand could lead to overinvestment and high costs of electricity. An understatement of demand could lead to underinvestment and shortage in electricity supply.

For the monopsonist Kenya Power and Lighting Company (KPLC), power purchase prices are based on contracts signed with the generators. The prices and uptake of generated energy are guaranteed for the period of the contract offering protection to the generators (Electricity Regulatory Board, 2005). The generators do not place a bid to sell their energy as would be the case in a competitive market (Kirschen and Strbac, 2004). This has the potential to diminish the efficiency incentive with negative consequences on electricity tariffs.

ERC in determining the retail tariffs considers not only the power purchase costs resulting from power purchase agreements but also the revenue requirements of KPLC. Dispatch, transmission and distribution are the natural monopoly network functions undertaken by KPLC. The tariffs are set to be at least equal to the cost incurred in rendering the transmission, distribution and retailing service under a cost of service regulation (Electricity Regulatory Board, 2005). While the power purchase price is directly associated with the power purchase agreements, the KPLC tariffs need to be interrogated with a view to understanding their push factors. As indicated in Kirschen and Strbac (2004) cost mistakes of service providers such as KPLC should not be passed to consumers.

Electricity tariffs include the entire value chain cost of electricity supply. As such the end user consumer price reflects the average cost of supply since all the costs of supply are included in the revenue requirements and distributed amongst the consumers based on the projected demand. Therefore, a study on the drivers of retail tariff would require an investigation into the build-up of cost of electricity supply including an analysis on the demand forecast, generation, transmission, distribution and retailing of electricity. The government is faced with a difficult balancing act of trying to provide quality and reliable supply of electricity and increase access while ensuring that electricity tariffs remain affordable. There is therefore need to explain the electricity tariffs by analysing the critical components of the electricity costs in the country. These will be critical in informing the regulator and policy makers on the areas to focus on in reducing electricity tariffs.

1.1. Energy sector

The main source of energy used in Kenya is biomass accounting for 69% of the primary energy consumption (Lahmeyer International GmbH, 2016). Biomass is mainly used for cooking and heating (Republic of Kenya, 2013b). Petroleum and electricity account for 22% and 9% of the country's primary energy source, respectively (Lahmeyer International GmbH, 2016). All petroleum products are currently imported even though this may change in future with the discovery of oil in Turkana. The volatile international oil prices typically put Kenya’s commercial sectors in a precarious position whenever oil prices go up (Republic of Kenya, 2013b).

Industrial and commercial sectors use a mix of energy sources including electricity and petroleum. Coal is also used by most cement factories to complement heavy fuel oil for process heating. Transport accounts for about 70% of petroleum consumption (Republic of Kenya, 2014). Households energy sources include electricity which is mainly used for lighting and firewood which is mostly used for cooking (Kenya National Bureau of Statistics (KNBS), 2018).

1.2. The electricity sub-sector and electricity consumption

The electricity subsector has been going through reforms since 1994. The reforms have seen Kenya Electricity Generation Company (KenGen) take over all government generation investments from KPLC. KPLC retained transmission and distribution assets. The transmission assets built after 2008, however, fall under Kenya Electricity Transmission Company (KETRACO). The Electric Power Act of 1997 allowed the participation of private investors in electricity generation and formation of an independent regulator for the sector, the Electricity Regulatory Board (ERB) to regulate the natural monopoly, KPLC. The mandate of the regulator was expanded in the Sessional Paper No 4 on energy. ERC is the energy sector regulator, while the Ministry of Energy makes policies on energy (Republic of Kenya, 2004). The Sessional Paper provided for the establishment of KETRACO, Geothermal Development Company (GDC) the Rural Electrification Authority (REA) and Energy Tribunal. The tribunal listens to appeals over decisions made by the sector regulator. KETRACO's role has been to expand transmission network. GDC attends to development of geothermal resources by drilling steam fields and selling geothermal steam to electricity generators. REA accelerates rural electrification by planning and implementing the rural electrification programme (Republic of Kenya, 2004). Several privately owned distribution companies (DISCOs) have also been licensed by ERC and are now in operation. Kenya Nuclear Electricity Board (KNEB) was established in 2012 to fast track the development of nuclear electricity generation in Kenya (Republic of Kenya, 2012a). Currently 15 independent power producers (IPPs) sell power to KPLC (KPLC,2018). These are: Iberafrica, Tsavo, Thika, Biojuole, Mumias, OrPower, Rabai, Triumph, Gulf, Imenti Tea Factory, Gikira, Regen-Terem Gura, Chania and Strathmore (KPLC,2018). The current institutional structure in the electricity subsector is shown in Figure 1-1.

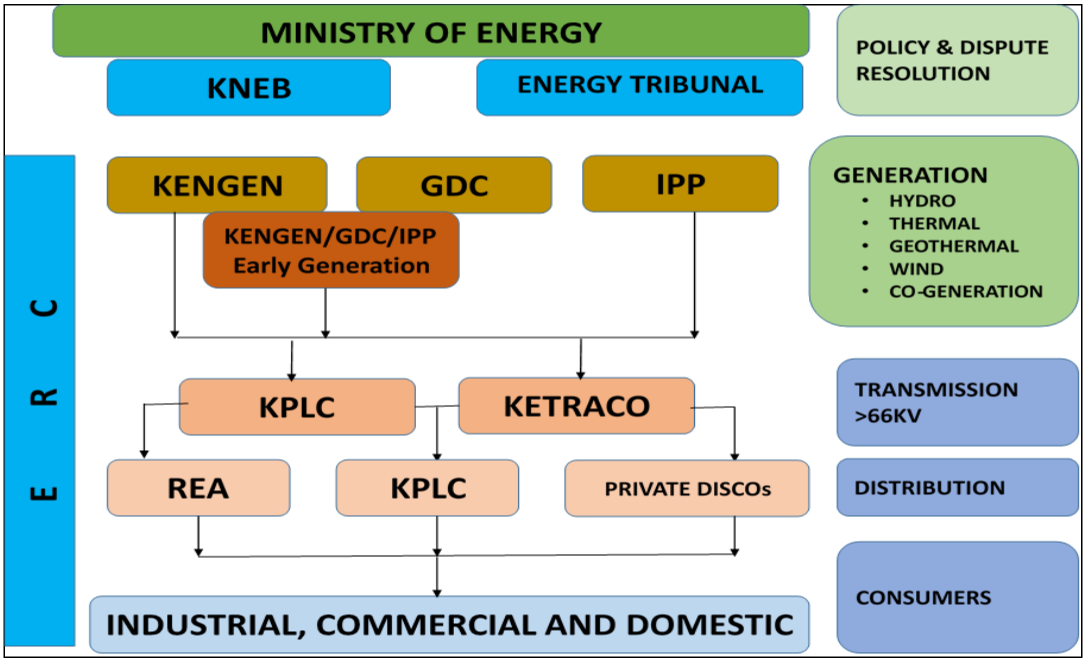

Figure 1.1: The structure of power sector in Kenya

Source: Republic of Kenya (2013a).

KenGen dominates electricity generation in Kenya contributing 74.7% of the system total energy. Of the remainder, 23.3% is generated by 15 privately owned companies while about 2% is from isolated projects in the rural areas and imports (KPLC, 2018). Most of the energy is generated from geothermal (47.2%) followed by hydro (30.1%), thermal (20.6%) and others (2.1%) (KPLC, 2018). Other forms of energy include wind, solar, biomass and imports.

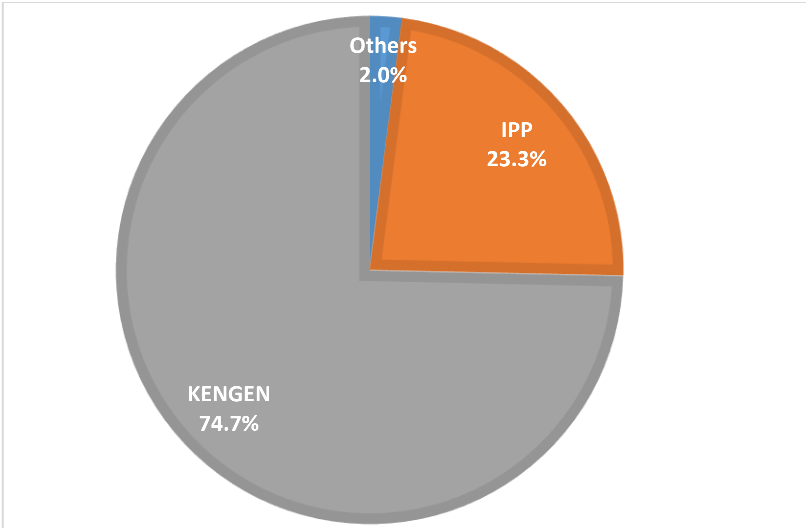

Figure 1.2: Share of generation by players

Source: Author's calculation from 2017/18 KPLC annual report statistics

The electricity supply mix is likely to change by the year 2022 as the country implements several planned generation projects. Approximately 1,453MW of renewable energy sourced from wind, solar and biomass are planned for implementation increasing their share in the supply mix to 28%. The planned 400MW imports from Ethiopia will contribute about 8% of the supply mix (Republic of Kenya, 2018b). Lahmeyer, International GmbH, (2016) projects the generation mix in the year 2035 to be 56% geothermal, 16% hydropower, 11% wind power, 7% imports, 6% coal, 4% cogeneration and solar.

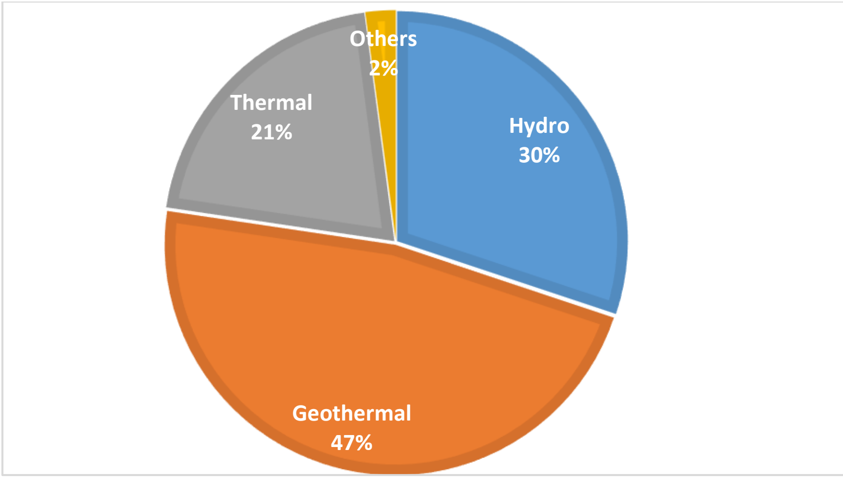

Figure 1.3: Share of generation by technology

Source: Author's calculation from 2017/18 KPLC annual report statistics

The power distribution and transmission network comprises of about 80,897km of medium and high voltage lines, and over 20,234 MVA transformation capacity. The high voltage transmission network consists of 6,252 km of 220kV and 132kV lines managed by KPLC and KETRACO and 74,644km of medium voltage distribution network managed by KPLC (KPLC, 2018). KPLC is a natural monopoly with large fixed capital and minimal variable costs associated with distribution and transmission companies as observed by Kirschen and Strbac (2004).

The government has continued to invest heavily in power generation, as well as in support infrastructure including transmission and distribution network. This was emphasized in the investment prospectus that planned to accelerate generation and transmission to a capacity slightly over 6700MW by 2016 (Republic of Kenya, 2013a). The expansion was expected to be implemented by public electricity utilities and IPPs under the public private partnership framework (Republic of Kenya, 2013a).

In line with the Vision 2030, the government through KPLC has continuously rolled out programs aimed at increasing electricity access by reducing connections costs. Currently there are two critical programmes for connecting domestic consumers with electricity namely, the last mile connection and slum electrification. Their objective was achievement of 70% access to electricity in the country by 2017 and universal connectivity in the medium term (KPLC, 2016). Through the two programs, the number of new electricity connections increased from 2,767,983 in June 2014 to 6,761,090 in June 2018 (KPLC, 2018). Electricity access rate has increased from 32% to 75% (Republic of Kenya, 2018a).

The consumers of electricity in Kenya are classified under five main categories: domestic, small commercial, commercial and industrial, off peak, and street lighting (KPLC, 2018). The highest consumers of electricity are commercial and industrial at an average of 56.6%, followed by domestic consumer at 26.6% (KPLC, 2018). Electricity consumption has experienced growth over the last 10 years. The highest consumption growth rate was recorded in 2010/11 and 2013/14. These high growth rates were mainly recorded as consumption recovered from periods of slowed growth. The lowest growth rates were recorded in 2008/09, 2012/13 and 2017/18. The periods were marked by low rainfall and elections. The average growth rate has been around 4.6%. Table 1-1 shows the consumption by customer in GWh, the percentage share by customer category and the growth rate.

Table 1.1: Electricity consumption in Kenya by customer category (GWh) 2008-2018

Types of Customers /Period	2008/ 9	2009/ 10	2010/ 11	2011/ 12	2012/ 13	2013/ 14	2014/ 15	2015/1 6	2016/ 17	2017/ 18	Aver.	Share (%)
Domestic	1254	1290	1424	1520	1670	1803	1866	2007	2138	2335	1731	26.6
Small Commercial	823	823	904	993	998	1109	1143	1153	1201	1222	1037	15.9
Commercial and Industrial	3020	3153	3401	3419	3440	3818	4030	4104	4266	4225	3688	56.6
Domestic Off-peak – Interruptible	43	36	38	43	18	1	15	26	41	33	29	0.5
Street lighting	15	16	18	16	18	20	35	40	55	66	30	0.5
Total	5155	5318	5785	5991	6144	6751	7089	7330	7701	7881	6515	
Increase per annum (%)	2.4	3.2	8.8	3.6	2.6	9.9	5.0	3.4	5.1	2.3	4.6	

Source: Author’s compilation from various KPLC annual reports

Generators sell electricity to KPLC at a bulk tariff negotiated through a power purchasing agreement between the generator and KPLC. The power purchasing agreement is approved by ERC who ensures the price is cost reflective and allows the generator to operate efficiently. The bulk tariff is normally for a period of 20 years. KPLC as the system operator dispatches, transmits and distributes energy to the consumers. It charges consumers a retail tariff which has to be approved by ERC. In determining the retail tariff ERC ensures that the costs of service are fully met (Electricity Regulatory Board, 2005)

The retail tariff is bundled and includes the cost of generation, transmission and distribution. The costing guides revenue requirements of KPLC. While, generation cost includes power purchase cost, transmission cost includes expenses for operating the transmission systems for both KETRACO and KPLC. It also captures distribution and marketing expenses and profit for the shareholders of KPLC. Electricity prices in Kenya are based on projections of total future costs of supply and demand. The pricing structure is designed to keep KPLC’s revenues in line with its costs (Electricity

Regulatory Board, 2005). It has a fixed charge, demand charge and energy charge (ERC, 2013).

From the fixed charge KPLC recovers retailing expenses such as metering, meter reading, billing and collection. The demand charge caters for transmission and distribution network management expenses. The energy charge per kWh meets revenue requirements of KPLC (Electricity Regulatory Board, 2005). The fixed and demand charges are constant, while the energy charge varies per kWh consumed (ERC, 2013). The tariff structure was reviewed in 2018 where fixed charge was removed in this tariff structure.

In the tariff structure, generation fuel expenses, foreign exchange associated losses and inflation adjustments are added and passed on to the consumers. They enter into retail bills as fuel oil cost adjustment (FOCA), foreign exchange rate fluctuations adjustment (FERFA) and inflation adjustment. FOCA and FERFA are adjusted monthly while inflation is adjusted semi-annually (Electricity Regulatory Board, 2005). The KPLC annual report captures the average yield of units which includes all the collections related to the sale of electricity including the pass-through costs (KPLC, 2018). As such the average yield is the average price of electricity.

Table 1-3 presents average electricity tariff per unit consumed in Kshs/kWh. The tariff increased from Kshs11.7/kWh in 2008/09 to Kshs14.6/kWh in 2017/18 contrary to Ministry of Energy targets. The targets projected energy purchase costs to drop to about Kshs7/kWh, end user tariff for commercial and industrial consumers to fall to Kshs 9/kWh and for domestic consumers to Kshs10.45/kWh by 2017 (Republic of Kenya, 2013a). The tariff comprised of 26% operational costs and 74% energy purchase costs.

Table 1.2: Costs per unit consumed

Cost/ Year	2008 /09	2009 /10	2010 /11	2011 /12	2012 /13	2013 /14	2014 /15	2015 /16	2016 /17	2017 /18
Energy Purchase Cost (Kshs/kWh)	9.1	10.1	8.0	11.7	10.1	10.8	10.3	9.6	10.3	10.2
Operational Costs (Kshs/kWh)	2.6	2.8	3.1	3.3	3.4	3.4	3.4	3.9	4.3	4.4
Tariff (Total cost) per unit (Kshs/kWh)	11.7	12.9	11.1	15	13.5	14.2	13.7	13.5	14.6	14.6
Share of Energy purchase cost (%)	78	78	72	78	75	76	75	71	70	70
Share of operation cost (%)	22	22	28	22	25	24	25	29	30	30

Source: Author’s compilation from various KPLC annual reports

1.3. Power sector reforms and policies

The establishment of the Kenya power sector can be traced back to 1922 when the East Africa power and lighting company (EAP&L) was formed following a merger of the Mombasa power and lighting company and Nairobi power and lighting syndicate, both privately owned (Republic of Kenya, 2013b). EAP&L later expanded to Tanzania and Uganda power sectors but retreated to its Kenyan base in 1964 following the involvement of the Governments in the power sector. With the operations confined to Kenya, EAP&L was renamed KPLC in 1983 and effectively operated as a vertically integrated company with the government of Kenya having majority shareholding and exercising discretionary powers granted by the Acts of Parliament. The government interference in the operations of KPLC conflicted with the structural adjustment and democracy programmes by the development partners necessitating the introduction of reforms in the sector (Godinho and Eberhard, 2019).

Power sector reforms were initiated in the early 1990s with the introduction of cost-reflective tariff as part of commercialization of KPLC in line with the 1992 policy paper on public enterprise reforms and privatization. The second set of reforms focused more on the power sector and were triggered by supply side crisis that saw the world bank support the procurement of two IPPs in 1996. The World Bank support was conditional on several reforms that included the government unbundling KPLC from a vertically integrated utility, allowing private sector participation in the sector, creation of an independent regulator and allowing competition in generation (Godinho and Eberhard, 2019). The unbundling of KPLC, liberalization of generation and establishment of an independent sector regulator was made possible by the Electric Power Act of 1997 (Republic of Kenya, 1997). Unbundling led to the creation of a fully government owned generating company KenGen. KPLC retained the responsibility of transmission and electricity distribution (Godinho and Eberhard, 2019).

Major reforms were witnessed in the period 2003–2013 mainly attributed to the change in government and leadership in 2002. The government was the driver of the reforms and developed the Sessional No. 4 of 2004 on energy. This policy paper set the agenda for the reforms that included the Energy Act of 2006, privatization of KenGen, expansion of the mandate of Electricity Regulatory Board to Energy Regulatory Commission and the establishment of REA, GDC and KETRACO (Godinho and Eberhard, 2019; Republic of Kenya, 2004). The enactment of the Energy Act also established the energy tribunal (Republic of Kenya, 2006). The retail electricity tariff review policy was also introduced in 2005. According to Godinho and Eberhard (2019), the period from 2003 to 2013 was marked with advancement in power sector reforms, improvements in sector performance and capacity development.

Other policies developed in this period include the feed in tariffs (FiT) policy that promotes generation of electricity from renewable energy sources. The first FiT policy was issued in 2008 easing the procurement of hydro, wind, solar, biomass, biogas, and geothermal projects (Republic of Kenya, 2012b). The Vision 2030 was also launched in 2008 with several development projects that required affordable and reliable energy as a foundation for their success. Some of the commitments in the Vision 2030 document included continued institutional reforms such as strong regulatory framework, encouraging private generators of power and separating generation from distribution and transmission. Other measures included finding new sources of energy such geothermal, coal, renewable energy sources and interconnecting with neighbouring countries (Republic of Kenya, (2007). Interconnectors currently under implementation by the country include one to Ethiopia, Tanzania, and Uganda. Completion of the interconnectors will facilitate trade within the Eastern African Power Pool (Republic of Kenya, 2018c). The Eastern African Power Pool was established in 2005 and currently has 11 members countries within the Eastern Africa region. Its goal is to promote pooling of energy resources and power exchange within the region (Eastern Africa Power Pool, 2016). The regime change following the elections of 2013 focused more on universal access to electricity and lowering electricity tariffs (Godinho and Eberhard, 2019). Some of the policy measures implemented included the Last Mile Connectivity Programme that aimed at connecting 1.2 million new customers, electrification of all public primary schools, informal settlement electrification program and the Rural Electrification Programme. This increased electricity access rate from 32% in 2014 to 75% in 2018. The Government launched the Kenya National Electrification Strategy in 2015 to accelerate universal access to the year 2022 from the initial target date of 2030 (Republic of Kenya, 2018a). However, there are concerns of government and political interference in power pricing, planning and procurement of projects that could negatively affect the sector. The universal access program could also have adverse financial impact on KPLC as the utility is unable to meet its billing and loss rate targets (Godinho and Eberhard, 2019).

In 2017, the government launched the Big four Agenda initiative. The targets included increased manufacturing, universal health coverage, food security and nutrition and affordable housing. The success of the program required expansion of electricity infrastructure. Consequently, the government has planned for the implementation of electricity generation, transmission, distribution, off-grid, and energy projects amounting to $14.8 billion (Republic of Kenya, 2018b).

A new set of reforms is underway with the enactment of the Energy Act 2019. The reforms are aimed at providing affordable energy to all and opening the subsector to competition. Some of the proposed reforms include developing an electricity market in generation, allowing open access to the distribution and transmission network to facilitate trade, allowing competition in the retailing functions of KPLC and separating selling and buying of power from system operation. The last reform is likely to reduce potential conflict of interest in the matching of demand and supply (Republic of Kenya, 2019).

1.4. Statement of the research problem

In spite of the electricity sector reforms that began in 1994, the government has not succeeded in providing affordable electricity to all citizens and the total cost of electricity supply has actually been rising. The rise was almost threefold from Ksh 38 billion in 2007/08 (KPLC, 2008) to Ksh 115 billion in 2017/18 (KPLC, 2018). Consequently, the government has failed to meet its target of reducing tariffs to about Ksh 9/kWh for commercial and industrial consumers, and Ksh10.45/kWh for domestic consumers by the year 2017 (Republic of Kenya, 2013a). The tariff for commercial and industrial consumers averaged Ksh 14.1/kWh while that of domestic consumers average Ksh 16.3/kWh in 2017/18.

The consumers and the government have been concerned with the rising cost of electricity in Kenya (Republic of Kenya, 2007; Gil-Alana, Mudida and Carcel 2017). Despite this concern no study has been undertaken to explore the critical underlying issues driving the rising costs. The study attempted to fill this gap by assessing if the demand forecasts in the sector are realistic or they could be causing over investment and hence increasing the cost of supply. The official estimates and projections of electricity demand use engineering models that assume commercial and industrial demand to be driven by GDP growth, and household demand to be driven by specific consumption in the household and number of customers (Republic of Kenya, 2013b; Lahmeyer

International GmbH, 2016). The drivers of demand and forecasts thereof in line with economic theory of demand have not been considered in Kenya's electricity subsector. Thus, there was need to use economic methods to estimate demand for electricity in Kenya and make projections. This was with a view to ascertain if the sector's official demand forecasts are realistic from an economic perspective. A high forecast could lead to overinvestment and huge costs of supply. KPLC as the electricity provider carries the risk of forecasting errors which can cause higher costs of electricity (Berk, 2015). Although the sector has been undertaking demand forecasts that inform the investment sequence, no study has been undertaken to assess if these forecasts are realistic or they could be unrealistic causing over investment and push up the cost of supply.

There was also need to investigate if the contracted generators operate efficiently. The government reform agenda recognized the need for efficiency in energy production, supply and delivery as a strategy for reducing the high electricity tariffs (Republic of Kenya, 2004). Despite this recognition and implementation of several reforms in the sector aimed at improving efficiency, no empirical study has been undertaken on efficiency of contracted generators in Kenya. Inefficiency of generators could be contributing to high electricity costs. Understanding the efficiency levels as well as the drivers of efficiency was considered critical in informing policy relating to tariffs.

The network service costs associated with transmission, distribution and retailing also determine cost of supply and tariffs. Throughout the reform process this segment of the electricity supply has remained a monopoly. The proposed reforms in the Energy Act, 2019 also retain the transmission, distribution and system operation as a natural monopoly (Republic of Kenya, 2019). There is therefore need to explain the monopoly pricing of electricity tariffs by exploring the push factors of KPLC costs. Dramani and Tewari (2014), Filippini, Wild and Kuenzle (2002), Filippini and Wild (1999) indicate that the average cost could be used for natural monopoly price regulation and to assess the performance of distribution utilities. But this has not been done in Kenya and this study attempted to fill the gap.

1.5. Research questions

This study seeks to address the general research question on whether the demand forecast, generation efficiency and KPLC tariffs are the critical underlying issues driving the rising costs of electricity. The specific research questions are:

1. Is the official demand forecast for electricity in Kenya realistic or could it be leading to overinvestment?
2. Has the electricity sub-sector in Kenya been generating electricity efficiently?
3. What drives the electricity tariffs in Kenya?

1.6. Objectives

The study overall objective was to investigate demand forecast, generation efficiency and electricity tariffs for the natural monopoly as the critical underlying issues driving the rising costs of electricity. The specific objectives were:

1. To forecast electricity demand in Kenya using economic methods
2. To assess the technical efficiency of thermal electricity generation in Kenya
3. To explain electricity tariffs in Kenya

1.7. Conceptual framework

The linkage between the electricity demand forecast, generation efficiency, transmission and distribution costs in the eventual price of electricity build up is shown below. The diamond shapes decision boxes represent the three critical issues that this study seeks to answer.

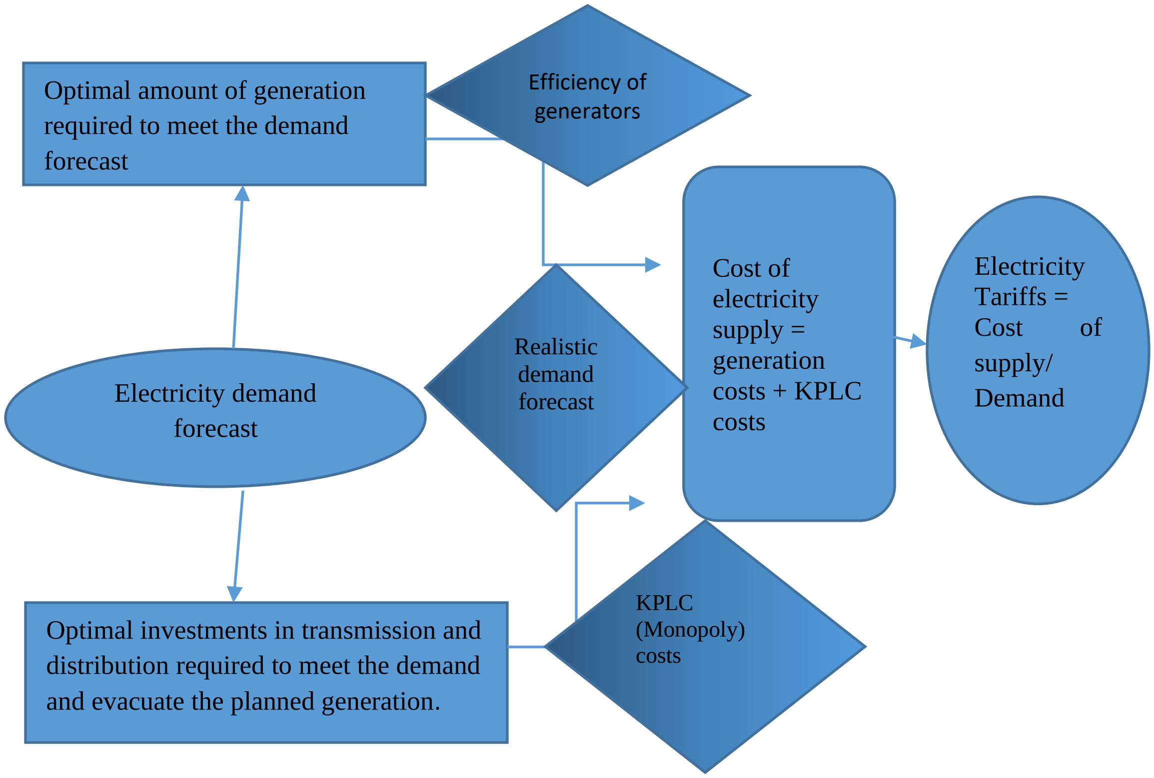

Figure 1.4: Conceptual framework of the relationship between electricity demand, generation efficiency, Transmission and distribution costs.

Source: Author

1.8. Significance of the study

The finding of this study informs the Ministry of Energy on what the demand for electricity is likely to be in future and the push factors of electricity tariffs. The demand forecast is important for investment planning and helps avoid overinvestment or underinvestment. ERC benefits from the findings of efficiency scores of the thermal generation plants in the making of future regulatory decisions on generation tariffs. It is also possible for ERC to use the findings of KPLC tariffs, a natural monopoly, in determining revenue requirements, setting efficiency targets and in future yardstick regulation of transmission and distribution utilities. The findings can be generalized to other African countries with similar market structures.

1.9. Thesis outline

The thesis is organised as follows: Chapter 2 presents the essay on forecast of electricity demand in Kenya. The essay also identifies the drivers and elasticities of demand for electricity in Kenya. In Chapter 3, the essay evaluated the technical efficiency of thermal electricity generators in Kenya and analysed the determinants of technical efficiency of the plants. In Chapter 4, the essay explained electricity tariffs in Kenya using cost observation for the natural monopoly KPLC, analysed the scale of operation and effects of reforms on electricity tariffs. Chapter 5 concluded the thesis and suggested policy direction.

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CHAPTER 2

ELECTRICITY DEMAND DRIVERS AND FORECAST IN KENYA

Abstract

The growth rate in electricity consumption from 2008/09 to 2017/18 in Kenya averaged 4.6%. This is much lower than the official projections of 13.5%. An over-estimation of demand is likely to result in high cost of power. There is need to match sector investments with growth in demand. The study used econometric method of ARDL and time series data from 1985 to 2016 to estimate the aggregate, residential, commercial and industrial demand for electricity and made projections to 2035. The results indicated that residential, commercial and industrial consumers' electricity demands are income elastic. The projections showed that aggregate demand for electricity will rise from 7,811GWh in 2017 to 21,655GWh by 2035, representing an average annual growth of 6%. The forecast was much lower than the subsector's official projection of 13.5%. This indicated that there is need for the government to re-evaluate its official projection so as not to encourage overinvestment. The Ministry of Energy should review its investment plans which are based on growth rate of 13.5%. Alternatively, all planned generators should be contracted on take and pay power purchase agreement instead of take or pay to avoid consumers paying for contracted idle capacity. Income, hydro inflows and price of diesel were found to be significant determinants of aggregate electricity demand. In addition, urbanization rate, hydro inflows and income significantly determined residential electricity consumption. The results further showed that efficiency, electricity price, output and hydro inflows were significant drivers of commercial and industrial electricity demand. The Ministry of Energy and the Energy Regulatory Commission can also trigger demand growth by addressing supply side constraints and encouraging economic growth. Commercial and industrial consumers will continue taking up the

highest share of electricity consumed. Government measures such as time of use tariffs, lower industrial tariffs and tax rebate programs should continue being implemented to encourage electricity demand growth among commercial and industrial consumers.

2.0 **Introduction**

Developing economies are likely to experience accelerated growth in electricity consumption resulting from economic growth and interventions that increase electricity access. In Africa, demand for electricity is increasing despite supply constraints. Sub-Saharan Africa lags behind in electricity access and per capita energy consumption (International Energy Agency, 2017). In Kenya, the development blueprint, Vision 2030, identifies energy especially electricity as an enabler of economic, social and political growth (Republic of Kenya, 2007). The per capita consumption of electricity in Kenya was 167kWh in 2014 (World Bank, 2017), more than Tanzania at 99kWh and Ethiopia at 70kWh. The figure is below Botswana’s 1749 kWh, Namibia’s 1585 kWh and Egypt’s 1658kWh (World Bank, 2017). The Kenya Vision 2030 indicates that per capita electricity consumption is changing rapidly as the country continues to invest more resources in electricity generation and policy reforms (Republic of Kenya, 2007).

To increase access to electricity the government formulated an energy access scale-up programme to connect one million households to electricity in the period 2008 to 2012 (Republic of Kenya, 2008). This target was met and surpassed slightly with the number of connections having increased from 924,329 as at June 2007 to 2,038,625 in June 2012 (Kenya Power and Lighting Company (KPLC),2012) and to 5,428,989in June 2018 of 95% of are domestic consumers (KPLC, 2018). However it is interesting to note that even with the one million new connections the per capita consumption only increased from 143.41kWh in 2007 to 157kWh in 2012 and an estimated 180.5kWh[1] in 2016 (Kenya National Bureau of Statistics (KNBS), 2018). As presented in Table 2.1, the consumption growth has been below the customer connections. Consumption growth

[1] Calculated from the Economic survey, 2018

rate averages 4.6% while the customer connections growth rate averages 19.9% for the period 2008/09 to 2017/18. This has resulted in a decrease in the annual average consumption per customer from 4,854 kWh to 1,452 kWh over the same period. This can be attributed to most of the new customers being domestic consumers who have low energy consumption. This trend is likely to continue as the government aims to implement universal electrification by the year 2022 (Republic of Kenya, 2018a).

Table 2.1: Consumption and number of customers

Description	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	Average
Consumption (GWh)	5155	5318	5785	5991	6144	6751	7089	7330	7701	7881	6515
Increase in consumption (%)	2.4%	3.2%	8.8%	3.6%	2.6%	9.9%	5.0%	3.4%	5.1%	2.3%	4.6%
Number of customers (Million)	1.06	1.21	1.44	1.66	1.88	2.24	2.91	3.92	4.91	5.43	2.67
Increase in Customers (%)	18%	14%	19%	15%	13%	19%	30%	35%	25%	11%	19.9%
Consumption per customer (kWh)	4,854	4,386	4,006	3,618	3,273	3,015	2,437	1,871	1,568	1,452	3,048

Source: Author's compilation from various KPLC annual reports

The universal electrification to households and businesses as well as the implementation of Vision 2030 projects informed the 5000MW power generation expansion plan (Republic of Kenya, 2018a). The installed capacity increased from 1765MW in 2013 (KPLC, 2013) to 2351MW in 2018 (KPLC, 2018) while the demand increased from 1354MW in 2013 to 1802MW in the same period (KPLC, 2018). This shows that the installed capacity was growing faster than the demand with an increase of 586MW against a demand increase of 448MW over the five-year period. The demand was lower than that projected by government. Government forecast estimated the demand to be 3,034MW (Republic of Kenya, 2013b) and 1,942MW (Lahmeyer, International GmbH, 2016) in the reference scenario. There is need for an accurate estimation of the quantum and pattern of future electricity demand growth. Demand forecasting informs and determines the requisite additional generation capacity. While over-estimation of demand could lead to over-provision and high costs, an underestimation could lead to under-provision.

Nevertheless, there is unmet demand due to supply side constraints and below 100% connectivity levels. The electricity access rate is 75% (Republic of Kenya, 2018a). This connectivity level is mainly due to insufficient coverage of the grid and inability of potential consumers to pay for electricity connection fee (Lahmeyer International GmbH, 2016). Recent policies aimed at increasing connectivity include connecting domestic consumers within 600metres of a transformer at a standardized fee of about Ksh 35,000, an amount that was further reduced to Ksh 15,000 in 2015 (KPLC, 2015). The supply constraints sometimes result in power rationing to the already connected consumers especially during drought periods when water levels in power dams go down. This shows the sector’s vulnerability to weather changes due to dependence on hydro generated power (Lahmeyer International GmbH, 2016).

2.0.1 **Statement of the research problem**

In 2013 the government rolled out an accelerated program to supply over 5000MW+ by 2016 (Republic of Kenya, 2013a). Despite the lowering of connection charges, electricity consumption growth has averaged only 4.6% from 2007/08 to 2017/18. This rate is lower than the projected growth of 13.5% in the least cost power development plan 2013-2033 (Republic of Kenya, 2013b). Based on historical trend, there are concerns that previous official forecasts have been overestimating the demand growth. The overestimation is costly to the government and the consumers because IPP investors receive payments for deemed energy resulting from non-utilization of their plants when the off-taker is unable to take more power (Republic of Kenya, 2018b). The payments are transferred as costs to the consumers escalating the price of power. The official demand forecast mainly use an engineering approach and a correlation factor between

GDP and electricity consumption. In this approach, commercial and industrial demand for electricity is assumed to depend on GDP growth while household demand is assumed to depend on household specific consumption and connected population (Republic of Kenya, 2013b). Forecasts based on economic models are missing in Kenya. The drivers of electricity demand in line with economic theory have not been considered in forecasting electricity demand. This is a gap that this study attempted to fill and went beyond to estimate price and income elasticity of electricity demand.

There is need for the country to have a robust forecast of demand for electricity to provide a level of certainty for the proposed investments. There is also need to identify the drivers of electricity demand at the macro-level using past performance indicators.

2.0.2 **Research questions**

This chapter attempted to answer the following question: What will be the electricity demand in Kenya by 2035 using economic modelling? From this general question stems issues such as: What drives electricity demand in Kenya? What are the price and income elasticities of demand for electricity? How would an econometric demand forecast compare with the official forecast?

2.0.3 **Objectives**

The broad objective of this chapter was to forecast electricity demand in Kenya to 2035. The specific objectives were:

1. To estimate the drivers of electricity demand in Kenya,
2. To forecast electricity demand for Kenya to 2035 using economic modelling

2.0.4 **Significance of the study**

The findings of this study informs policy makers on the variables that drive electricity demand and the elasticities of demand. The identification of the key drivers of aggregated electricity demand are key to the electricity subsector planners. Knowledge on the key drivers inform future demand forecasts. The planners utilizing the findings are better informed and will have a basis for policy formulation on the indicators to monitor in assessing future electricity demand growth.

The study provides an alternative methodology of forecasting electricity demand. International Atomic Energy Agency (1988) recommends the use of supplementary methods to ensure a robust demand forecast. The methodology in this study supplements the end user model currently used by the sector planners.

The study contributes to literature on the price and income elasticities of electricity demand. Price elasticity of demand is important key to the regulator as it indicates consumer's responsiveness to price changes. The study also contributes to literature by examining the effects of supply side constraints on demand for electricity.

2.1 **Literature review**

2.1.1 **Theoretical Literature**

The demand of a commodity can be defined as the quantity of a commodity a consumer is willing and able to buy at a given time and price, holding all other factors constant. According to Bhattacharyya (2011) a distinction can be made between consumption and demand for electricity. Electricity demand is the link of economic variables and the quantity of electricity in Gigawatt hours (GWh) that consumers are willing to purchase at the going price. It exists before purchase is made. Electricity consumption starts when the electricity is purchased. Electricity demand indicates the quantities that will be purchased given certain economic variables, while consumption indicates the quantities actually consumed. The quantity demanded of a good is mainly determined by its price and income (Jehle and Reny, 2011).

The factors affecting consumption and demand for electricity vary with economic activity (Bhattacharyya and Timilsina, 2009). Consumers of electricity are faced with either a utility maximization or cost minimization objective (Bhattacharyya, 2011). As households consume electricity, they derive utility. Consumption level varies with income. Higher income may be linked to higher electricity consumption assuming that the consumers observe the assumptions of preference set ordering and rationality (Bhattacharyya and Timilsina, 2009). Firms use electricity as an input in production. Thus, demand for electricity in firms is a derived demand (Bhattacharyya, 2011). Therefore, in analysing electricity demand, households and firms need to be treated differently. Households energy demand is domiciled on consumer theory. Firms as producers use the theory of production to determine demand for energy as a factor of production (Bhattacharyya, 2011). The theory of the producers is used to determine the demand for factors of production for the firms faced with the cost minimization problem (Bhattacharyya, 2011). Firms produce the level of output requiring the least money outlay. This point is achieved when the marginal rate of substitution of any two inputs is equal to the ratio of their prices. The solution to the cost minimization problem is the conditional input demand, which is conditional on the level of the firms output (Jehle and Reny, 2011).

Consumer theory postulates that consumers know their preference sets and ordering (Bhattacharyya, 2011). Consumer preference relations are summarised by the utility function. The consumer problem hence becomes that of utility maximization subject to a budget constraint (Jehle and Reny, 2011). The maximum utility is achieved at the point where the marginal rate of substitution is equal to the economic rate of substitution (Bhattacharyya, 2011; Jehle and Reny, 2011). The solution to the consumer's utility maximization problem is the ordinary or the Marshallian demand function (Jehle and Reny, 2011). Where expenditure data is available, the expenditure function which defines the minimum expenditure necessary to attain a specific utility level at given prices is used (Deaton and Muellbauer, 1980). The consumer's Hicksian demand function is the solution to the expenditure minimization problem (Jehle and Reny, 2011). Hicksian and Marshallian demand functions have an equal solution (Jehle and Reny, 2011; Ngui, Mutua, Osiolo and Aligula, 2011).

According to Bhattacharyya (2011) the relevant demand elasticities in any energy analysis relate to output, price and income. Inglesi and Blignaut (2011), Ziramba and Kavezeri (2012) and Liu (2004) examine income and price elasticities. Bhattacharyya (2011) distinguishes between short and long run price elasticities. The short run price elasticity shows the immediate and partial response to price changes when consumers are limited in capital stock change. The long run elasticity provides the effects of extended period changes, when consumers can adjust their stocks and consumption behaviour.

There are two approaches used in estimating electricity demand: top-down and bottom-up methods. Bottom-up approach is common in engineering models. Demand is broken down into small components such as sector and subsector with the focus being on the end –uses. The overall demand is taken as the sum of this small components. The top-down approach is an aggregate analysis of demand common in economics. It's considered a global approach that looks at the demand for electricity much like the demand for any other good or service and is grounded on demand theory. The top down approach has the advantage over the bottom up approach by capturing the effects of price on demand and inter-fuel substitution. Bottom up approach does not consider the role of prices as the focus is not on the transitory phase (Bhattacharyya, 2011).

The relationship in a demand function is used in forecasting. This is accomplished by changing the independent variables and determining their effect on the dependent variable (Bhattacharyya, 2011). Changes in the independent variables are based on judgement (Bhattacharyya, 2011), indicators such as growth rates (Bhattacharyya, 2011), trend method (Bhattacharyya, 2011 and Ghaderi, Azadeh and Mohammadzadeh, 2006a) and or a combination of these methods (Amarawickrama and Hunt, 2007, Dilaver and Hunt, 2010a, Inglesi, 2010, Adom and Bekoe, 2012 and Bhattacharyya, 2011). Scenarios analysis is also undertaken, Amarawickrama and Hunt (2007) and

Adom and Bekoe (2012) considered three scenarios, Dilaver and Hunt (2010a) five and Inglesi (2010) two.

Forecasting electricity demand

There are several methods existing for forecasting electricity demand in the world. Ngui, Wasike and Mutua (2012) classify the models into bottom-up, top-down and integrated. Bottom-up models are engineering type and focus on the end uses of demand. Top down models are aggregated macro models that establish the linkages of economic growth, prices and other variable on energy demand. Integrated models are multi-disciplinary that use varied methodologies to integrate knowledge from individual disciplines. Feinberg and Genethliou (2005) indicates that end-use and econometric approaches are broadly used for medium and long- term forecasting. For short term forecasts similar day approach, time series, neural networks, expert systems, fuzzy logic, and statistical learning algorithms methods are used.

The official forecast of electricity demand in Kenya is based on end use approach. The forecast of electricity consumption is undertaken for each consumer group based on the retail tariffs consumer grouping. That is domestic, street lighting, small commercial and large commercial and industrial consumers (Republic of Kenya, 2013b, and Lahmeyer International GmbH, 2016).

Domestic, street lighting and small commercial consumer's consumption is estimated by forecasting the specification consumption in kWh per year for each of the consumer group and multiplying it with the projected number of connections. This requires that an estimate is made on each of the consumer group specific consumption for the base and forecast periods. The base is normally based on the past data while the forecasts are assumptions based on judgement. The projections on the number of customers are estimated using population growth forecasts. The commercial and industrial consumer's consumption forecast is arrived at by multiplying the base electricity consumption with the GDP forecast and the correlation factor. The correlation factor is estimated using past GDP and electricity consumption data. The total consumption is the summation of the forecasts from each of the end-users (Lahmeyer International GmbH, 2016). This method is consistent with the description provided by Bhattacharyya (2011) for end –use or bottom up demand forecasting approaches where the demand is estimated working backwards.

The end use approach makes a lot of assumptions and judgements on the consumption patterns of households due to unavailability of sufficient data (Lahmeyer International GmbH, 2016) and this reduces the reliability of the estimates. Further, the role of prices in the demand is not considered as is traditional of such models (Bhattacharyya, 2011). According to Mehra and Bharadwaj (2000) planners often use several methods and compare the forecasts. International Atomic Energy Agency (1988) indicates that both the econometric/global approach and end use method should be carried out jointly to supplement each other. In the econometric approach energy demand is treated like demand for any other good or service, by exploring the price and quantity relationship. Bhattacharyya (2011) indicates that end-use and econometric methods are used for long-term forecasting.

These econometric approaches have been used in several studies to forecast electricity demand. The studies treat electricity demand as a normal good, a demand equation is estimated using time series data (see Adom and Bekoe, 2012; Dilaver and Hunt, 2010a, Inglesi, 2010; Inglesi and Pouris, 2010). These studies use several estimation approaches including ARDL, structural time series and Engel and granger error correction models. Structural time series model is a state space model that allows for the introduction of a stochastic or deterministic trend in the estimation of demand, such that the underlying energy demand trend is included as an explanatory variable of the demand (Dilaver and Hunt, 2010a; 2010b). Engel and granger error correction model allows for the use of regression analysis in analysing the demand (Inglesi, 2010). ARDL model has been discussed in detail in section 2.2.1 of this chapter. In all the models, the forecast follows and uses the determined demand relationship. The independent variables are changed to include their future forecasts and used to determine the dependent variable. The independent variables are forecasted using judgement, growth rates and trend analysis (Bhattacharyya, 2011).

2.1.2 **Empirical literature**

Demand for electricity has empirically been estimated based on the traditional assumption that demand for a product is determined by price and income holding other factors constant. Erdogdu (2007) finds electricity demand in Turkey to be determined by income and price. Chaudhry (2010) analysis of 63 countries for the period 1998-2008 finds per capita income and price to be significant determinants of electricity demand. In Pakistan, Khan and Ahmed (2009) find the demand for electricity in the short run to be determined by previous period electricity demand, income and changes in price. Alter and Syed (2011) in an estimation of electricity demand for Pakistan find contrary results that show a long run relationship exists, and income, electricity price, number of customers and electricity appliances to be significant determinants of demand.

Lin (2003) identifies electricity demand for China to be a function of GDP, price, population, structural changes and efficiency. GDP and population affect demand positively while price, structural changes and efficiency have a negative effect. The variables determine demand in the long and short run. Issa and Bataineh (2010) in examining the determinants of electricity demand in Jordan find per capita GDP, electricity price and efficiency significant. GDP affects electricity demand positively while price and efficiency have a negative effect. The results are consistent with those of Lin (2003) and economic theory.

In Africa, Inglesi (2010) estimates the total electricity demand for South Africa using GDP, electricity price, disposable income, electricity consumption, and population as the independent variables. The results show that electricity demand is driven by disposable income and price of electricity in the long run, and GDP and population in the short-run.

Ekpo, Chuku and Effiong (2011) in their investigation of aggregate electricity demand in Nigeria find that electricity use is positively driven by income, population and industrial sector output.

In Namibia, Ziramba and Kavezeri (2012) estimate the aggregate electricity demand using real price and real GDP. Their findings show the effect of price on electricity demand to be insignificant. This finding is inconsistent with an earlier study by Vita, Klaus and Lester (2005). Vita et al. (2005) estimate of total energy demand in Namibia by type (i.e., electricity, petrol and diesel) find electricity price, GDP and temperature to be significant causes of electricity demand.

In examining elasticities of electricity demand, Ekpo et al. (2011) find that the long run and short run income elasticity of electricity demand in Nigeria to be 0.58 and 0.22 respectively, and those of price to be -0.44 and -0.23 respectively. Alter and Syed (2011) find the long and short run income elasticity of electricity demand in Pakistan to be 0.251 and 0.315 respectively, and of price to be -0.853 and -0.189, respectively. Erdogdu (2007) finds long and short run income elasticity of electricity demand in Turkey to be 0.414 and 0.057, respectively, and for price to be -0.297 and -0.047, respectively. With the exception of Alter and Syed (2011), the other country findings are consistent with the suggestion by Ramskov and Munksgaard (2001) that long run elasticities tend to be bigger than the short run elasticities due to the adjustment process between the two periods.

In Jordan, Issa and Baitaineh (2010) find income elasticity of electricity demand to be 0.29 and price elasticity of demand to be -0.09. In China, Lin (2003) estimated elasticity for two periods 1952-2001 and 1978 -2001. The study finds income elasticity of electricity demand to be 0.856 and 0.78 respectively. The price elasticities are –0.037 and -0.016 for the two periods, respectively. Vita et al. (2005) finds the income and price elasticity of electricity demand for Namibia to be 0.589 and -0.298, respectively. A later study in Namibia by Ziramba and Kavezeri (2012) finds income elasticity of electricity demand to be 1.121, and of price to be -0.32. Inglesi (2010) finds the income and price elasticity of electricity demand in South Africa to be 0.42 and -0.56 respectively. Most of the studies find income and price inelasticity of demand for electricity, with price being more inelastic than income. This finding indicates that most consumers consider electricity to be an essential good and are unlikely or do not have a substitute.

Empirical literature on household electricity demand

Empirical research on residential electricity demand dates to the 1970's. Wills (1977) in a study of Massachusetts, finds electricity space heating to be the critical driver of consumption besides price and income. Kamerschen and Porter (2004) in estimating residential demand for electricity in USA also find marginal price for residential electricity as well as annual GDP, residential natural gas price and annual cooling degree days in the electricity quantity equation to be significant determinants of residential electricity demand. A more recent study by Herath, Gebremedhin and Fletcher (2011) finds average retail electricity price, natural gas price and population to be determining factors of residential electricity demand in the southern region of USA. Jorgensen and Joutz (2012) also finds average electricity price, income and natural gas price to be significant drivers of electricity in the USA. Similarly, Neeland (2009) finds electricity price changes and real income growth per capita to be the main causes of residential demand for electricity in the USA. These studies find electricity demand in the US behaves like a normal good, with income having a positive elasticity and own price having a negative elasticity.

Athukorala and Wilson (2009) find household electricity demand in Sri Lanka to be determined by electricity price, income and kerosene price. They find liquefied petroleum gas (LPG) to be a significant alternative to electricity in the short run. Dilaver and Hunt (2010a) find price, household expenditure and demand trend for residential electricity to be significant determinants of residential electricity consumption in

Turkey. In Philippines, Onuh, et al (2011) finds that the number of appliances, income and price to be the main determinants of residential electricity consumption. This finding is inconsistent with an earlier study for Philippines by Francisco (1988) that found income to be an insignificant determinant, and price to be a positive determinant. Francisco (1988) attributes the positive price coefficient to evolution of the rate schedule structure.

Filippini, Boogen and Blazquez, (2012) find previous period electricity consumption, disposable income, price, household size, access to gas, population and weather to be the main determinants of residential electricity demand in Spain. Theodoros and Pashourtidou (2006) find weather changes to cause variation in electricity consumption in the short term and income and prices in the long run in Cyprus. Holtedahl and Joutz (2004) find income, electricity price, oil price, urbanization and weather to be the main determinants of residential demand for electricity in Taiwan. Fillipini and Pachauri (2002) estimates of electricity demand in India during each of the three seasons - winter, monsoon and summer find price of electricity, level of income, size of household and town to be significant determinants in all the three seasons.

The findings of studies undertaken in Africa have not departed significantly from those undertaken in other parts of the world. Babatunde and Shuaibu (2009) find population, income, price of substitutes to be the main determinants of residential electricity demand in Nigeria. Guta, Damte and Ferede (2015) find GDP per capita, electricity price and urbanization to be the main drivers of household electricity demand in Ethiopia. Mabea (2014) finds price and income to be the determinants of household demand for electricity in Kenya. The findings in Africa are similar to those of Athukorala and Wilson (2009) in Sri Lanka and Fillipini and Pachauri (2002) in India.

In examining elasticity of residential electricity demand, literature shows the demand to be price inelastic in the long run and income elastic in some cases. Deliver and Hunt

(2010a) finds income and price elasticity of residential electricity demand in Turkey to be 1.57 and -0.38 respectively. The short run income and price elasticity is 0.38 and -0.09, respectively. Holtedahl and Joutz (2004) find income elasticity of 0.23 in the short run, and 1.04 in the long run. The short run price elasticity is -0.16 and -0.15 in the long run. In Cyprus, Theodoros and Pashourtidou (2006) find income and price elasticity of residential electricity demand to be 1.175 and - 0.427, respectively.

Some studies find demand for electricity to be income and price inelastic. These studies include Fillipini and Pachauri (2002), Athukorala and Wilson (2009), Jorgensen and Joutz (2012), Fillipini et al. (2012), Babatunde and Shuaibu (2009), Mabea (2014) and Guta et al. (2015). Fillipini et al. (2012), show that long run income and price elasticity for residential electricity demand in Spain is 0.30 and -0.24, respectively. In the short run, income and price elasticity is 0.14 and -0.11, respectively. In Sri-Lanka, Athukorala and Wilson (2009) show that long run residential electricity demand, is income and price inelastic at 0.78 and -0.62, respectively. In the short run, income and price elasticity is 0.32 and -0.16, respectively. Jorgensen and Joutz (2012) find demand for electricity in the US to be income and price inelastic in the long run at 0.271 and -0.182, respectively. In India, Fillipini and Pachauri (2002) find income elasticity of residential electricity demand to be 0.64 in winter, 0.63 in summer and 0.604 in Monsoon. The price elasticity of demand is -0.42 in winter, -0.29 in summer and -0.51 in monsoon. Price elasticity of demand varies more with seasons than income elasticity of demand.

In Africa electricity demand is income as well as price inelastic. Babatunde and Shuaibu (2009) show income and price elasticity of electricity demand in Nigeria in the long-run to be 0.193 and 0.058, respectively. In the short run, income and price elasticity is 0.10 and 0.03, respectively. They attribute the positive signs to the government of Nigeria fixing electricity prices and rarely reviewing them. In Ethiopia, Guta et al. (2015) estimate short run income and price elasticity of demand for electricity at 0.093 and -0.238, respectively. The long run elasticities are 0.304 and -0.173, respectively. In

Kenya, the income and price elasticity of residential electricity demand is 0.1 and -0.095, respectively (Mabea, 2014).

Empirical literature on commercial and industrial electricity demand

Literature on commercial and industrial electricity demand is quite limited. The earliest work in this area is by Francisco (1988) in Philippines. The work examines the determinants of commercial and industrial electricity demand focusing on price, income, price of alternatives, price of electricity consuming appliances, environmental factors and system peak load. The results show that electricity price, income and price of alternatives are significant determinants while system peak load is insignificant and negative.

Some studies consider price and income/output as the drivers of commercial and industrial electricity consumption. These include Bianco, Manca, Nardini and Minea (2010) in Romania, Bernstein and Madlener (2010) in Germany, Chaudhry (2010) in Pakistan, and Bjørner and Togeby (1999) in Denmark. Cebula and Herder (2010) find that consumption of electricity by commercial and industrial consumers in USA increasing with cooling degree days, per capita disposable income and electricity generating capacity. Consumption decreases with price of electricity and energy efficiency.

Dilaver and Hunt (2010b) show that industrial electricity demand in Turkey is driven by industrial value addition, electricity price and the underlying trend. Ghaderi, Azadeh and Mohammadzadeh (2006b) find the demand drivers of various industrial sectors in Iran to include electricity prices, number of industrial customers and industrial value addition. Their earlier study (2006a) has price of substitutes and electricity intensity as additional drivers of demand.

Estimates of elasticity of demand for commercial and industrial electricity are varied. Cebule and Herder (2010) find income elasticity of 1.57 and price elasticity of -0.887 in

US. Bjornerand and Togeby (1999) have income and price elasticity for Denmark at 0.611 and -0.473, respectively. In Turkey, Dilaver and Hunt (2010b) find income and price elasticity of 0.15 and -0.161, respectively. Bianco et al. (2010) in Romania find short run income and price elasticity of 0.136 and -0.0752, respectively. The long run elasticities are slightly higher at 0.496 and -0.274, respectively.

In Pakistan, Chaudhry (2010) finds the income and price elasticity of commercial and industrial demand is 0.194, and -0.574, respectively. Comparable estimates in Iran are 0.11 and -0.21, respectively (Ghaderi et al., 2006b). Separating high from low energy consuming industries in Iran, Ghaderi et al. (2006a) find high energy consuming industries to be price elastic with an elasticity of -2.92. Low energy consuming industries have a price elasticity of -0.93.

Empirical literature on demand forecasting

Most of the studies reviewed extended the demand analysis to demand forecast and compared the results of their forecast with the official forecast. Apart from Bianco et al. (2009) in Italy who find the forecast for 2010–2030 to be close to the official forecast, all the other studies find the official forecast higher. These include Amarawickrama and Hunt (2007) for Sri lanka, Inglesi and Pouris (2010) for South Africa, Ghaderi et al. (2006a) for Iran, and Dilaver and Hunt (2010a) for Turkey. The deviations between own and official forecast in Amarawickrama and Hunt (2007) and Inglesi and Pouris (2010) are attributed to use of an end user model in the government forecast and non-inclusion of price. Bianco et al. (2009) indicates the official forecast for Italy is based on a macroeconomic model. This could explain the closeness in the study and official forecasts.

The studies reviewed predicted the regressors using available national statistics and judgement. Adom and Bekoe (2012) forecast for Ghana for the period 2009-2020 applies ARIMA forecasting technique to obtain forecasts for the predictor variables with no national projections. Inglesi (2010) uses judgement in predicting future values of price and economic growth in the electricity demand forecast for South Africa for the period 2009-2030, the other forecast for South Africa by Inglesi and Pouris (2010) for the period 2009-2025 uses a combination of judgement and national statistics in predicting the future values of price, population and economic growth. Amarawickrama and Hunt (2007) Sri Lanka electricity demand forecast for the period 2004–2025 uses national statistics to predict the values of GDP, price and population. Dilaver and Hunt (2010a) Turkey's electricity demand forecast for 2010-2020 uses judgement in predicting the values of price and household final expenditure. Scenario analysis are included in the forecasts, Amarawickrama and Hunt (2007), Ghaderi et al. (2006a), Dilaver and Hunt (2010a) and Adom and Bekoe (2012) considers three scenarios, Inglesi (2010) and Inglesi and Pouris (2010) consider two scenarios.

2.1.3 **Overview of literature review and research gap**

From the studies reviewed, the main determinants of demand for electricity are income, electricity price, and price of alternatives or substitute energy forms. Other determinants are temperature (cooling degree days), number of customers and energy intensity. Temperature may, however, not be a relevant determinant in the Kenyan case. The climate is warm all year round with minimal variations in temperatures.

The reviews of elasticity of demand for electricity showed varied results across consumer groups and countries. Long-run elasticities were found to be higher than short-run elasticities. This could be attributable to the period required for consumers to adjust to price and income changes. In both the developing and developed countries, demand for electricity was found to be price inelastic. Demand was found to be more responsive to income changes than to price changes.

The studies reviewed compared their forecasts with the official forecast. The official forecasts were mostly found to be higher. The time periods considered in the forecasts varied from seven to twenty years. The regressors used for forecasting were predicted using available forecasts from national statistics and judgement. Scenario analysis were considered in the studies reviewed three scenarios; low, medium and high were mainly considered.

None of the studies reviewed considered the impact of supply side constraints on demand. There is need to include these aspects in simulating the future demand for fuels. This study attempts to fill the gap by estimating the impact of improvements of supply side constraints on electricity demand.

2.2 Methodology

2.2.1 Theoretical framework

Electricity is both a consumer good as well as an input in production. As an input, its demand is derived from the demand of output produced (Alter and Syed, 2011). Bhattacharyya (2011) indicates that modelling energy demand starts with establishing the link between energy use and stock of capital equipment. The link is expressed as

$$Q_i \equiv \sum_{K=1}^{M} R_{ki} A_{ki} \qquad 2.1$$

where Q_i is the total consumption of fuel i used in k appliances. Fuel used by the appliance is the product of stock of appliance (A) and utilization rate (R) in kWh. The stock and utilization rate are given in Bhattacharyya (2011) as

$$A = f_1(p_i, p_j, p_a, Y, X) \text{ and } R = f_2(p_i, Y, Z) \qquad 2.2$$

where p_i is electricity price, p_j is price of alternative fuel j, p_a is the appliance price, Y is income or output, X and Z are other relevant control variables and R is utilization rate. From 2.1 the total consumption of electricity in kWh is the sum of the product of consumption of each of the k appliances and the consumption rate. This is represented as

$$E = \sum_{k=1}^{M} R_k A_k \qquad 2.3$$

If information on rate and stock is available, electricity demand could be estimated directly. In the absence of such data a reduced form demand equation similar to equation 2.3 could be estimated as in Bhattacharyya (2011). Thus,

$$E = k(p_i, p_j, p_a, Y, X, Z) \qquad 2.4$$

There are several methods of estimating equation 2.4 depending on available data. Where time series data is available most studies use error correction models in estimation (see Ziramba and Kavezeri, 2012; Alter and Syed, 2011; Inglesi, 2010; Athukorala and Wilson, 2009; Neeland, 2009; Khan and Ahmed, 2009; Theodoros and Pashourtidou, 2006; Holtedahl and Joutz, 2004; and Lin, 2003). Others use structural time series analysis in estimation (e.g., Dilaver and Hunt, 2010b), two stage least squares estimation (e.g., Herath et al., 2011), simultaneous equation method (e.g., Kamerschen and Porter, 2004) Autoregressive Distributed lag model (ARDL) (e.g., Vita et al., 2005; Ziramba and Kaverenzi, 2012 and Ekpo et al., 2011), least squares estimation (e.g., Issa and Bataineh, 2010), and dynamic models (e.g., Bianco et al., 2009; and Erdogdu, 2007).

ARDL bounds test approach to cointegration is particularly appealing due to its ability to work with both stationary and nonstationary data according to Pesaran, Shin and Smith (2001), and with small sample data according to Belloumi (2014). Further, ARDL bounds test approach provides unbiased estimates even when some of the regressors are endogenous (Adom and Bekoe, 2012). Since time series data may have structural breaks which introduce some uncertainty on the variables order of integration, bounds test approach resolves this problem by first establishing a cointegrating relationship among the variables, and secondly by estimating the short and long run coefficients (Narayan and Smyth, 2005).

The long run relationship is determined using ARDL bounds test approach to cointegration. Integration of the short run and the long run is done without losing any long run information. By integrating short run dynamics with long run dynamics, cointegration allows retrieval of long run information lost in differencing. Differencing is done to attain stationarity of nonstationary time series variables (Nkoro and Uko, 2016).

Following Narayan and Smyth (2005), to implement the bounds test approach consider a vector of two variables z_t where $z_t = (y_t x_t')'$. y_t is the dependent variable and x_t is a vector of regressors. In an electricity demand model, Δy_t could be modelled as a conditional ECM as in Narayan and Smyth (2005) and Pesaran et al. (2001) such that:

$$\Delta y_t = \beta_0 + \beta_1 t + \beta_2 D_1 + +\beta_3 D_2 + \pi_{yy} y_{t-1} + \pi_{yxx} x_{t-1} + \sum_{i=1}^{p} \vartheta_i \Delta y_{t-i} + \sum_{j=0}^{q} \emptyset_j' \, \Delta x_{t-j} + \theta w_t + \mu_t \qquad 2.5$$

where β_0, t , D_1 and D_2 are drift, time trend, connections and reform dummy variables respectively. π_{yy} and π_{yxx} are long-run multipliers and w_t is a vector of exogenous variables.β_0, The bound test for absence of a relationship between y_t and x_t is through exclusion of y_{t-1} and x_{t-1} in equation 2.5, that is, $H_0{:}\, \pi_{yy} = \pi_{yxx} = 0$. Restricting β_0 and β_1 tests for no intercepts and no trend, that is, $\beta_0 = 0 \; and \; \beta_1 = 0$ and unrestricting intercepts and not trends, i.e., $\beta_0 \neq 0 \; and \; \beta_1 = 0$. Equation 2.5 depicts unrestricted intercepts and unrestricted trend, $\beta_0 \neq 0 \; and \; \beta_1 \neq 0$. The null hypotheses of no level relationship suggests that, $\pi_{yy} = 0, and \; \pi_{yxx} = 0'$. The alternative hypotheses is $\pi_{yy} \neq 0, and \; \pi_{yxx} \neq 0'$. The critical values for the two tests is provided by Pesaran et al. (2001) as bounds for cases with I (0) and I (1) variables.

Demand forecasting extends the relationship established in the demand analysis. This is done by changing the independent variables and determining their effect on the dependent variable. The forecasting follows the same steps followed in the demand analysis (Bhattacharyya, 2011). The values of $x_{t+j,}\, j = 1,2 \ldots p$, is taken as given and to compute $y_{t+j,}\, j = 1,2 \ldots p$ using the ARDL model (Adom and Bekoe, 2012).

2.2.2 **Empirical analysis**

The aggregate, household, and commercial and industrial demand models were estimated. The aggregate demand was then used to forecast the demand for electricity in Kenya to 2035. This is the same period used in the official forecast.

ARDL bounds test approach to cointegration was used to test for the existence of a long-run relationship. Engle–Granger cointegration testing procedure was not applied due to its preference for two variables that must be integrated of the same order (Enders, 2014). Johansen Cointegration technique was also limited due to the study small sample and several variables. This was likely to lead to the Johansen trace test giving misleading number of cointegrating relations (Odour, 2008). A mixture of I (0) and I (1) regressors was also likely to affect the interpretation of the test (Pesaran et al., 2001).

Diagnostic stability tests were done for all the identified long run relationships. The tests included LM serial correlation test, normality test, heteroskedasticity test, Cumulative sum of recursive residuals (CUSUM) and CUSUM of Squares Tests. Unit root test were also undertaken to determine the order of integration of each of the variables. This was to satisfy the requirement for the variables to be either I (1) or I (0) for the bounds testing approach to cointegration to be used (Pesaran et al., 2001).

Aggregate demand for electricity in Kenya

Following Lin (2003) and Alter and Syed (2011) the general form of the aggregate demand for electricity in Kenya was specified as

$$E = f(GDP, P, EF, H, C, DP, D_1, D_2) \qquad 2.6$$

where E was electricity consumed, GDP was gross domestic product, P was electricity price, EF was Energy Efficiency, H was hydro inflows, C was total number of customers, DP was the price of diesel, D_1 was dummy variable for connections and D_2 was dummy variable for reforms in the sector. Diesel price was introduced to take care of substitutes as suggested by Bhattacharyya (2011) and represented the price of alternative fuels. The dummy variables were included to correct for structural changes in the data.

Following Alter and Syed (2011) equation 2.6 was expressed as;

$$E_t = e^{\alpha} GDP_t{}^{a}\ P_t{}^{b}\ EF_t{}^{c}\ H_t{}^{d} C_t^{e}\ DP_t^{f}\ e^{\alpha_1 D_1} e^{\alpha_2 D_2}\ e^{\varepsilon_t} \qquad 2.7$$

where $\alpha,\ a,\ b,\ c,\ d,\ e,\ f,\ \alpha_1$ and α_2 were the regression coefficients, ε was the error term and t was time period.

Taking the logarithm of equation 2.7

$$ln\, E_t = \alpha + alnGDP_t + bln\, P_t + \ clnEF_t + dlnH_t + \ elnC_t + flnDP_t + \alpha_1 D_1 + \alpha_2 D_2 + \ \varepsilon_t \qquad 2.8$$

In log form, the coefficients measure the percentage change in the dependent variable as a result of a percentage change in the independent variable. Hence, the estimated coefficients were elasticities.

The error correction model of equation 2.8 was equation 2.9.

$$\Delta ln\, E_t = \alpha_0 + \alpha_1 D_1 + \alpha_2 D_2 + \emptyset_1 ln\, E_{t-1} + \emptyset_2 lnGDP_{t-1} + \emptyset_3 ln\, P_{t-1} + \emptyset_4 lnEF_{t-1} + \emptyset_5 lnH_{t-1} + \emptyset_6 lnC_{t-1} + \emptyset_7 lnDP_{t-1} + \sum_{i=1}^{n} \Delta\beta_1 ln\, E_{t-i} + \sum_{i=0}^{n}\ \Delta\beta_2 lnGDP_{t-i} + \sum_{i=0}^{n} \Delta\beta_3 ln\, P_{t-i} + \sum_{i=o}^{n} \Delta\beta_4 lnEF_{t-i} + \sum_{i=0}^{n} \Delta\beta_5 lnH_{t-i} + \sum_{i=0}^{n} \Delta\beta_6 lnC_{t-i} + \sum_{i=0}^{n} \Delta\beta_7 lnDP_{t-i} + \ \varepsilon_t \qquad 2.9$$

where α_0 was a constant, α_1 and α_2 were the coefficients of the dummy variables, $\emptyset_1 \ldots . \emptyset_7$ were long run coefficients and $\beta_2 \ldots \beta_7$ were short run coefficients. Other variables were as earlier defined.

The long run ARDL model was specified as

$$\ln E_t = \sum_{i=1}^{p} \emptyset_1 \ln E_{t-1} + \sum_{i=0}^{q_1} \emptyset_2 \ln GDP_{t-1} + \sum_{i=0}^{q_2} \emptyset_3 \ln P_{t-1} + \sum_{i=0}^{q_3} \emptyset_4 \ln EF_{t-1} + \sum_{i=0}^{q_4} \emptyset_5 \ln H_{t-1} + \sum_{i=0}^{q_5} \emptyset_6 \ln C_{t-1} + \sum_{i=0}^{q_6} \emptyset_7 \ln DP_{t-1} + \varepsilon_t \quad 2.10$$

The error correction model (ECM) took the form

$$\Delta \ln E_t = \alpha_0 + \alpha_1 D_1 + \alpha_2 D_2 + \sum_{i=1}^{p} \Delta\beta_1 \ln E_{t-i} + \sum_{j=1}^{q} \Delta\beta_2 \ln GDP_{t-i} + \sum_{l=1}^{q} \Delta\beta_3 \ln P_{t-i} + \sum_{m=1}^{q} \Delta\beta_4 \ln EF_{t-i} + \sum_{p=1}^{q} \Delta\beta_5 \ln H_{t-i} + \sum_{r=1}^{q} \Delta\beta_6 \ln C_{t-i} + \sum_{r=1}^{q} \Delta\beta_7 \ln DP_{t-i} + \varepsilon_t \quad 2.11$$

Data type, source and measurement

The study used time series data from 1985 to 2016. The data was sourced from various sources including KPLC annual reports, Kenya National Bureau of Statistics (KNBS) Economic Surveys and Statistical Abstracts, World Bank, World Development Indicators and Kenya Electricity Generating Company (KenGen).

Table 2.2: Definition and measurement of variables used to estimate aggregated demand for electricity

Variable	**Definition and measurement**	**Source of variable and data**
E_t	Total annual electricity sales in GWh.	Lin (2003), Alter and Syed (2011), Ziramba and Kavezeri (2012) and, Bhattacharyya, (2011) KPLC various annual reports
P_t	Real price of electricity (Ksh/200kWh) based on February 2009 prices.	Lin (2003), Alter and Syed (2011), Ziramba and Kavezeri (2012) and, Bhattacharyya (2011) KNBS various statistical abstracts
EF_t	Energy efficiency. Calculated by dividing the constant annual value added by industry in constant (base 2009) Ksh with the total energy consumption in kilotonne of oil equivalent(ktoe).	Lin (2003). Total energy consumption was as reported in the various Economic Surveys of the Kenya National Bureau of Statistics. The industry value added was collected from the World Bank, World Development Indicators.
H_t	Total annual hydro inflows in cubic metre per second (cumecs).	This was introduced to test for effects of supply side constraints on demand. Data collected from KenGen
GDP_t	Real GDP in Ksh million	Lin (2003), Alter and Syed (2011), Ziramba and Kavezeri (2012) and, Bhattacharyya (2011) World Bank, World Development Indicators
C_t	Total number of customers	Alter and Syed (2011) KPLC various annual reports

DP_t	Real price of Diesel in Ksh/Litre based on February 2009 prices.	Vita et al. (2005) and Bhattacharyya (2011) KNBS various statistical abstracts
Connections	1985-2002 = 0, and 2003-2016 = 1.	A dummy that corrects for structural breaks in GDP and price of electricity in 2003. The break can be associated with the reforms of 2003.
Reforms	1985 - 1997 = 0 and 1998 – 2016=1	Captures the first sector reforms that unbundled KPLC and set up KenGen and ERC.

Source: Author

Empirical results and discussion

Summary statistics

Table 2.3: Summary statistics for variables used to estimate aggregate electricity demand

Variable	Unit of measure	Mean	Std. deviation	Min	Max
GDP	Kshs trillion	2.35	0.83	1.28	4.3
Hydro inflows	Cumecs	862	262	466	1559
Energy efficiency	Kshs/ ktoe	137732	12519	116654	165786
Number of customers	No.	1074599	1252212	205486	5536328
Electricity sales	GWh	4079	1589	1944	7551
Price of electricity	Kshs /200 kWh	56	44	7	138
Diesel Price	Kshs/liter	66	47	9	148

Source: Author's computation from KPLC, KNBS, World Bank and KenGen data.

Table 2.3 provides the summary statistics of the variables used in the analysis before the logarithmic transformation. The GDP in constant value increased from Kshs 1.3trillion in 1985 to Kshs 4.3trillion in 2016. Hydro inflows averaged 862 cubic metre per second. The least inflows of 466 cubic metre per second were associated with the drought of 2008. The highest inflows of 1559 cubic metre per second were recorded in 1997. This was during the El Niño phenomena period that affected weather conditions in the World inducing heavy rains in Kenya (Karanja and Mutua, 2000). The number of customer's average 1,074,599 per annum. The standard deviation was 1,252,212. This can be attributable to the accelerated connections that begun in 2008/9 following the launch of the Vision 2030 and the Energy Access Scale-up Programme (Republic of Kenya, 2007). Electricity consumption averaged 4,049GWh per annum, having increased from 1,944GWh in 1985 to 7,551GWh in 2016. This is lower than the projected demand of 13,809GWh (Republic of Kenya. (2013b) and 10,093GWh (Lahmeyer, International GmbH, 2016). Electricity price averaged Kshs 56/200 kWh with the highest price being Kshs 138/200kWh in 2014. This followed an increase in the electricity tariff that took effect in December 2013 (ERC,2013). Diesel prices averaged Kshs 66 per liter with the highest price being Kshs 148/liter in 2012. The high oil prices were attributed to a rise in international oil prices emanating from supply disruption associated with political unrest in some of the oil producing countries (KNBS, 2012).

Table A.1 in Appendix 1 provides the summary statistics of variables used in the analysis after the logarithmic transformation. The graphical representation of the data is presented in Figure A.1 in Appendix 1. The graphs indicated the possibility of hydro inflows and electricity sales series having structural breaks. A correlation matrix is provided in Table A.2 in appendix 1. The results indicated high correlation between GDP and number of customers which maybe a sign of a collinearity problem. Multi-collinearity was confirmed by coefficient variance decomposition multi-collinearity test. As indicated in Bhattacharyya (2011) GDP representing income and own price are critical variables in the electricity demand model. The highly correlated variables were dropped checking for their effects on signs of the coefficients, significance and multi-collinearity (Green, 2003). The model was estimated without the number of customers and energy efficiency. The results of the coefficient variance decomposition multi-collinearity tests are presented in Table A.3 in Appendix 1.

Diagnostic tests

Unit root tests

Table 2.4: Unit root test for variables used to estimate aggregate electricity demand

Variable	ADF	PP	KPSS	Breakpoint	Conclusion
GDP_t- Intercept	1.478095	1.096816	0.74549	-1.799460	The series are stationary at level at 5% level of significance based on the breakpoint unit root test; Intercept and Trend -Trend only.
Intercept and Trend	0.067374	-0.43694	0.172282	-4.955523	
H_t - Intercept	-4.789928	-3.973428	0.316628	-6.210899	The series are stationary at level at 1% level of significance based on the ADF, PP and breakpoint unit root test.
Intercept and Trend	-5.314256	-6.277660	0.286215	-6.098086	
E_t- Intercept Level	0.360137	-0.164702	0.745770	-3.520577	The series are stationary at level at 1% level of significance based on the breakpoint unit root test; Intercept and Trend -Intercept only.
Intercept and Trend	-2.182911	-1.695257	0.126432	-6.084939	
P_t- Intercept	-1.254885	-1.254885	0.71490	-2.677943	The series are stationary at level at 1% level of significance based on the breakpoint unit root test; Intercept and Trend -Intercept only.
Intercept and Trend	-2.386906	-2.395306	0.140567	-6.76245	
P_{dt} - Intercept	-1.810358	-1.756573	0.704354	-3.453266	The series is I(1), that is stationary at first difference based on all the tests
Intercept (Difference)	-4.560880	-4.617837	0.302711	-5.814177	
Intercept and Trend	-0.112620	-0.207704	0.171692	-4.205323	
Intercept and Trend 1st difference	-5.261424	-5.261424	0.093688	-6.037986	

Source: Author's estimates from KPLC, Economic surveys, World Bank statistics and KenGen data.

Critical levels 1%, 5%, and 10% significance levels are as follows; Intercept - ADF(-3.662,-2.960,-2.619), PP (-3.661661,-2.960411,-2.619160), KPSS (0.739000, 0.463000, 0.347000), Break point[2] (-4.949133, -4.443649, -4.193627) Intercept and Trend -ADF(-4.309824, -3.574244, -3.221728) PP (-4.296729, -3.568379, -3.218382), KPSS (0.216000, 0.146000, 0.119000), Break point[3]; (-5.347598, -

[2] In Eviews, the breakpoint includes two structural break dynamics. Innovational outlier (IO) model assumes that the break occurs gradually. Additive outlier (AO) model assumes the breaks occur immediately. The critical values are for IO.

[3] Eviews includes three models for trend and intercept. These are; trending data with intercept break, trending data with intercept and trend break, and, trending data with trend break.

4.859812, -4.607324 – Intercept only; -5.719131, -5.17571, -4.89395 - Trend and intercept; -5.067425, -4.524826, -4.261048- Trend)

As indicated in Table 2.4 the Unit root tests found the variables to be either I (0) or I (1). The application of ARDL bounds testing approach that requires variables to be I (0) or I (1) (Pesaran et al., 2001) could proceed. In addition, structural breaks were found to have occurred in 2003 in the case of GDP and price of electricity, and in 1998 in the case of sales and hydro inflows.

Model selection

The model lag length was retained at 1. This is because at lag length two and above the model failed the LM serial correlation test. At lag length 1 the no intercept no trend model failed the Normality test, Heteroskedasticity and the CUSUM tests. The intercept with trend model also failed the Heteroskedasticity, CUSUM and CUSUM of squares tests. As presented in Table 2.5, the selected model at lag length 1 based on Akaike information criterion was ARDL (1, 1, 0, 0, 1).

Table 2.5: Aggregate electricity demand model Selection results

Model	Akaike information criterion
ARDL (1, 1, 0, 0, 1)	-4.730829
ARDL (1, 1, 0, 0, 0)	-4.712426
ARDL (1, 1, 0, 1, 1)	-4.671272
ARDL (1, 1, 1, 0, 1)	-4.670448
ARDL (1, 0, 0, 0, 0)	-4.665680

Source: Author's estimates from KPLC, Economic surveys, World Bank statistics and KenGen data.

Residual and Stability tests

Table 2.6: Aggregate electricity demand model residual and stability test results

Description	LM serial correlation	Normality	Heteroskedasticity	CUSUM and CUSUM of squares	Conclusion
Intercept no trend	0.306105	0.7914	0.1489	Within the confines of the 5% significance	Diagnostic tests passed

Source: Author estimates from KPLC, Economic surveys, World Bank statistics and KenGen data.

The results of the diagnostic and stability test for the intercept no trend ARDL model (1, 1, 0, 0, 1) are presented in Table 2.6. The model passed all the diagnostic tests.

Cointegration test results

Table 2.7: Bounds test Cointegration results for the Aggregate demand model

Description	Critical Values		F statistics	Conclusion
Restricted intercept, no trend	I (0)	I (1)	13.27537	Long run relationship exists
	2.2 (10%)	3.09 (10%)		
	2.56 (5%)	3.49 (5%)		
	3.29 (1%)	4.37 (1%)		

Source: Author's estimates from KPLC, Economic surveys, World Bank statistics and KenGen data.

The intercept and no trend ARDL model (1, 1, 0, 0, 1) was subjected to a Bounds test to cointegration. The results found a long- run relationship exists details of which are shown in Table 2.7.

Demand for electricity in Kenya

Table 2.8: ARDL estimates of elasticities of demand for electricity in Kenya

Variable	Coefficient
Short run	
Constant	-7.978*** (2.360)
Electricity Sales (t-1)	-0.502*** (0.119)
Hydro inflows (t-1)	0.041** (0.017)
GDP	0.410*** (0.114)
Electricity price	-0.006 (0.023)
Diesel Price (t-1)	0.064* (0.031)
Change in Hydro inflows	0.012 (0.014)
Change in Diesel Price	0.006 (0.033)
Connections	0.060*** (0.016)
Reforms	-0.056*** (0.018)
Error Correction Term	-0.502*** (0.051)
Long run	
Hydro inflows	0.081** (0.040)
GDP	0.817*** (0.077)
Electricity price	-0.013 (0.045)
Diesel Price	0.127** (0.048)
Constant	-15.901*** (2.056)

Source: Author's computation from KPLC, KNBS, World Bank and KenGen data.

Notes: *** indicates ceofficient is signifcant at 1% level; ** indicates ceofficient is significant at 5% level; * indicates ceofficient is significant at 10% level. Figures in paranthesis are the standard errors.

As presented in the results in Table 2.8, the short run elasticities were found to be smaller than the long run elasticities. This could be attributed to the limited flexibility in the short run compared to the long run. The error correction term was found to be negative and significant indicating convergence to the equilibrium in the long-run.

In the short run, a 1% increase in GDP increased electricity demand by 0.4% while in the long run, a 1% increase in the GDP increased demand by 0.82%. The finding is consistent with economic theory and literature where demand for a normal good is expected to increase with income. Aggregate demand for electricity is income inelastic. The finding is consistent with other studies undertaken in Africa (Vita et al., 2005 for Namibia, Ekpo et al., 2011 for Nigeria and Inglesi, 2010 for South Africa) that found income to significantly determine electricity demand and demand for electricity to be income inelastic.

Hydro inflows representing supply side constraints were found to affect electricity demand in the short and long run. Increase in hydro inflows increased demand in the next period by 0.04% in the short run. In the long run, an increase of 1% in hydro inflows resulted in an increase in electricity demand of 0.081%. This showed that supply constraints have the potential to limit demand for electricity resulting in unmet demand.

Diesel prices were found to positively affect electricity demand in the short and long run. In the short run a 1% increase in diesel price increased electricity demand in the next period by 0.06%. In the long run, a similar increase of 1% increased electricity demand by 0.127%. This suggests that diesel and electricity could be remote substitutes in production. It confirms the suggestion by Bhattacharyya (2011) that electricity has substitutes. The finding differs with that of Vita et al. (2005) that found diesel and kerosene not to be substitutes of electricity in Namibia. This they attributed to availability and reliability of grid connected power in Namibia. This may not be the case in Kenya which experienced frequent power outages averaging 19,588 per month (KPLC, 2017).

The results also indicated that consumers were likely to reduce electricity demand in the short run based on their previous period demand levels. An increase in demand in the previous period of 1% would reduce demand by 0.5%. Reforms were found to have a negative effect on demand, decreasing it by 0.056%. This can be attributed to the severe drought that followed the reforms, high capital access costs and economic recession that saw the demand decline between 1998-2001 (Republic of Kenya, 2004). Connections strategies and the second set of reforms in the power sector following the 2002 political regime change increased electricity demand by 0.06%.

Household demand for electricity

Following Guta et al. (2015), the general model for household demand for electricity was expressed as

$$HE = f(GPD, P_h, P_k, DT, U, H, C_h, D_1, D_2) \qquad 2.12$$

HE was electricity demand by the households. GDP was gross domestic product (a proxy for household real disposable income). Bhattacharyya (2011) indicates the economic driving variable for should be either GDP or private consumption. Mabea (2014) uses GDP as a proxy for real household income. However, using the national GDP as a proxy for household's income could exaggerate real household incomes. P_h was electricity price, P_k was price of alternative fuel (Kerosene), DT was capacity of distribution transformers, U was rate of urbanization, H was hydro inflows and C_h was number of household consumers. D_1 and D_2 were dummies to correct for structural breaks. They represented connections and reforms in the electricity sector. Transformer capacity was a proxy for access rate while hydro inflows represented supply side constraint.

As in Guta et al (2015), equation 2.12 was re-expressed as

$$HE_t = e^{\alpha} GDP_t{}^{a}\ P_{ht}{}^{b}\ P_{kt}{}^{c} DT_t{}^{e} e^{fU_t}\ H_t{}^{g}\ C_{ht}^{h}\ \ e^{iD_1}\ e^{jD_2}\ e^{\varepsilon_t} \qquad 2.13$$

$\alpha, a, b, c, e, f, g, h, i$ *and* j were coefficients to be estimated, ε was the error term and t was the time period.

Equation 2.13 was also re-written in log form as

$$ln\ HE_t = \alpha + alnGDP_t + bln\ P_{ht} + cln\ P_{kt} + \ elnDT_t + \ fU_t + glnH_t + \\ + hlnC_{ht} + iD_1 + jD_2 + \varepsilon_t \qquad 2.14$$

Equation 2.14 was estimated using ARDL method. The long run relationship was determined using bounds test to cointegration which estimated the following equation

$$\Delta \ln HE_t = \alpha + \sum_{i=1}^{n} \beta_i \Delta ln\ HE_{t-i} + \sum_{i=0}^{n} a_i\ \Delta lnGDP_{t-i} + \sum_{i=0}^{n} b_i \Delta ln\ P_{ht-i} + \\ \sum_{i=0}^{n} c_i \Delta ln\ P_{kt-i}\ + \sum_{i=o}^{n} e_i \Delta\ lnDT_{t-i} + \sum_{i=0}^{n} f_i \Delta\ U_{t-i} + \sum_{i=0}^{n} g_i \Delta\ lnH_{t-i} + \\ \sum_{i=0}^{n} h_{\ i}\ \Delta\ lnC_{ht-i} + \emptyset_1 ln\ HE_{t-1} + \emptyset_2 lnGDP_{t-1} + \emptyset_3 ln\ P_{ht-1} + \ \emptyset_4 ln\ P_{kt-1} + \\ \emptyset_5 lnDT_{t-1} + \emptyset_6 U_{t-1} + \emptyset_7 lnH_{t-1} + \emptyset_8 lnC_{ht-1} + iD_1 + jD_1 + \ \varepsilon_t \qquad 2.15$$

where β_i, a_i, b_i, c_i, e_i, f_i, g_i, $h_{\ i}$, i *and* j were the short run coefficients and $\emptyset_1 \ldots . \emptyset_8$ were the long run coefficients.

Data and measurement

The analysis used data from KPLC annual reports, Kenya National Bureau of Statistics Economic Surveys and Statistical Abstracts, World Bank, World Development Indicators and KenGen for the period 1985-2016.

Table 2.9: Description and measurement of variables used to estimate household demand for electricity in Kenya.

Variable	**Definition and measurement**	**Source of variable and data**
HE_t	Total Electricity sold to households (GWh).	Mabea (2014) and Fillipini, et al. (2012) KPLC annual reports
P_{ht}	Real price of electricity in Ksh/200 kWh based on February 2009 prices.	Herath, et al. (2011) KNBS various statistical abstracts
P_{kt}	Real price of kerosene per liter (ksh/liter) based on February 2009 prices.	Athukorala and Wilson (2009), Fillipini and Pachauri (2002) and Babatunde and Shuaibu (2002). KNBS various statistical abstracts
DT_t	Total annual capacity (MVA) for distribution transformers.	This was introduced to assess the impact the distribution network on demand. KPLC various annual reports
U_t	Annual rate of urbanization in percentage.	Guta et al. (2015) and Holtedahl and Joutz (2004) World Bank, World Development Indicators.
H_t	Total annual hydro inflows (Cumecs).	This was introduced to test for effects of supply side constraints on demand Data collected from KenGen
GDP_t	Annual constant GDP in Ksh.	Mabea (2014) and Bhattacharyya (2011) World Bank, World Development Indicators
C_{ht}	Total number of domestic customers.	Jorgensen & Joutz (2012) KPLC various annual reports
Connections	1985 - 2001 = 0 and 2002- 2016 = 1	Dummy variable captured the second set of reforms in the power sector and government regime change.
Reform	1985 - 1997 = 0 and 1998 – 2016=1	Reforms dummy. Captures the first sector reforms in the sector that unbundled KPLC and set up KenGen and ERC.

Source: Author

Empirical results and discussion

Table 2.10: Summary statistics of variables used in estimating the households electricity demand

Variable	Mean	Std. deviation	Min	Max
GDP	2.35	0.83	1.28	4.30
Hydro	862	262	466	1559
Electricity consumed by households	955	482	353	2073
Number of Domestic consumers	934646	1170100	165773	5173687
Distribution transformers	3084	1870	1056	7182
Price of Kerosene	58	46	3	142
Price of Electricity	56	44	7	138
Urbanization rate	4	0	4	5

Source: Author’s computation from KPLC, KNBS, World Bank and KenGen data.

Table 2.10 provides the summary statistics of the variables used in the estimation before the logarithmic transformation. GDP, hydro inflows and electricity price summary statistics are as described earlier. Household electricity demand averaged 955GWh. Demand increased from 353GWh in 1985 to 2,073GWh in 2016. The demand had increased over five times. This growth is slower than that reported by Guta et al. (2015) for household consumers in Ethiopia. The number of domestic customers increased over thirty times from 165,773 in 1985 to 5,173,687 in 2016 with a mean of 934,646 per year. Distribution transformation capacity increased seven-fold from 1,056MVA to 7,182MVA. The growth in customers and transformation capacity can be attributed to the Vision 2030 policy interventions on Energy Access Scale-up Programme (Republic of Kenya, 2007). Urbanization rate changed minimally in the period under consideration averaging 4.46% with the minimum rate of 4.04% being recorded in 1989 and the highest of 5.01% recorded in 1991. World Bank (2016) indicates Kenya is underperforming in urbanization, with an actual urban population share of 27% against an estimated 40%. The highest kerosene price of Kshs 142/liter was reported in 2011 a period that was marked by high international crude fuel prices (KNBS, 2012).

The summary statistics for the variables used in the analysis after logarithmic transformation are provided in Tables A.4 in Appendix 1. Figure A.2 in Appendix 1 provides the graphical presentation of the data used in the analysis. Some variables such urbanization rate and hydro inflows indicated the possibility of having structural breaks.

The correlation matrix presented in Table A.5 in Appendix 1 indicated high correlation between the variables. This necessitated a multi-collinearity test. Coefficient variance decomposition test was undertaken and confirmed the presence of multi-collinearity. Several models were estimated and checked for multi-collinearity, signs of the coefficients and goodness-of-fit. The selected model dropped number of customers, distribution transformers and price of kerosene. Table A.6 in Appendix 1 provides the results of the coefficient variance decomposition.

Diagnostic tests
Unit root test

Table 2.11:Unit root test of variables use to estimate households electricity demand

Variable	ADF	PP	KPSS	Breakpoint	Conclusion
GDP $_t$- Intercept	1.478095	1.096816	0.74549	-1.799460	The series are stationary at level at 5% level of significance based on the breakpoint unit root test; Intercept and Trend -Trend only.
Intercept and Trend	0.067374	-0.43694	0.172282	-4.955523	
H_t - Intercept	-4.789928	-3.973428	0.316628	-6.210899	The series are stationary at level at 1% level of significance based on the ADF, PP and breakpoint unit root test.
Intercept and Trend	-5.314256	-6.277660	0.286215	-6.098086	
P_t- Intercept	-1.254885	-1.254885	0.71490	-2.677943	The series are stationary at level at 1% level of significance based on the breakpoint unit root test; Intercept and Trend -Intercept only.
Intercept and Trend	-2.386906	-2.395306	0.140567	-6.76245	
HE_t - Intercept	0.400266	-0.171525	0.747728	-2.713228	The series are stationary at level at 1% level of significance based on the breakpoint unit root test; Intercept and Trend –Trend and Intercept.
Intercept and Trend	-1.656481	-1.344491	0.119869	-8.246190	
U_t- Intercept	-2.418932	-2.181026	0.202213	-2.784077	The series are stationary at level at 1% level of significance based on the breakpoint unit root test; Intercept and Trend -Intercept only.
Intercept and Trend	-3.030703	-2.165395	0.103179	-12.56227	

Source: Author’s estimates from KPLC, Economic surveys, World Bank statistics and KenGen data.

Critical levels 1%, 5%, and 10% significance levels are as follows; Intercept ADF(-3.662,-2.960,-2.619), PP (-3.661661,-2.960411,-2.619160), KPSS (0.739000, 0.463000, 0.347000), Break point (-4.949133, -4.443649, -4.193627) Intercept and Trend ADF(-4.309824, -3.574244, -3.221728) PP (-4.296729, -3.568379, -3.218382), KPSS (0.216000, 0.146000, 0.119000) Break point; (-5.347598, -4.859812, -4.607324 – Intercept only; -5.719131, -5.17571, -4.89395 - Trend and intercept; -5.067425, -4.524826, -4.261048 –Trend only)

Units root test presented in Table 2.11 found the variables were stationary at level I (0). Structural breaks were found to occur in 1998 for hydro inflow and electricity consumed by domestic consumers and in 2002 for urbanization rate. This affirmed the need to use ARDL model and include the dummy variables to correct for the structural breaks.

Model selection

The model at lag length 1 failed the CUSUM and CUSUM of squares stability test. At Lag lengths four and above the model failed LM serial correlation test, CUSUM and CUSUM of squares stability test. At lag 3 the no intercept no trend and intercept and trend models failed the LM serial correlation test, the later also failed the CUSUM stability test. The Akaike information criteria selected the ARDL model (3, 2, 2, 2, 2), the results of which are presented in Table 2.12.

Table 2.12: Households electricity demand model selection results

Model	Akaike information criterion
ARDL (3, 2, 2, 2, 2)	-5.92152
ARDL (3, 2, 3, 2, 2)	-5.921151
ARDL (3, 3, 2, 2, 2)	-5.919022
ARDL (2, 3, 2, 2, 3)	-5.917353
ARDL (3, 3, 2, 2, 3)	-5.91539

Source: Author's estimates from KPLC, Economic surveys, World Bank statistics and KenGen data.

Residual and Stability test

Table 2.13: Residual and stability test results for Household electricity demand

Description	LM serial correlation	Normality	Heteroskedasticity	CUSUM and CUSUM of squares	Conclusion
Intercept and no trend model ARDL (3, 2, 2, 2, 2)	0.2781	0.760089	0.1937	within the confines of the 5% significance	Diagnostic tests passed

Source: Author's estimates from KPLC, Economic surveys, World Bank statistics and KenGen data.

The ARDL (3, 2, 2, 2, 2) with a constant and no trend passed all the residual and stability diagnostic tests details of which are provided in Table 2.13.

Cointegration test

Table 2.14**:**Bound test Cointegration results for the Household Demand model

Description	Critical Values		F statistics	Conclusion
Restricted intercept, no trend	I (0)	I (1)	12.23547	Long run relationship exists
	2.2 (10%)	3.09 (10%)		
	2.56 (5%)	3.49(5%)		
	3.29(1%)	4.37 (1%)		

Source: Author's estimates from KPLC, Economic surveys, World Bank statistics and KenGen data.

Table 2.14 presents the bounds test cointegration results. The test found the presence of a long- run relationship between household electricity demand, GDP, price of electricity, urbanization rate and hydro.

Determinants of household demand for electricity in Kenya

Table 2.15: ARDL estimates result of elasticities of household demand for electricity in Kenya[4]

Variable	Coefficient
Short Run	
C	-8.315(3.191)
Electricity consumed by households(t-1)	-0.233*(0.109)
GDP (t-1)	0.299** (0.131)
Price of electricity (t-1)	-0.015(0.018)
Urbanization rate(t-1)	0.107***(0.029)
Hydro Inflows (t-1)	0.144**(0.048)
Change in Electricity consumed by households(t-1)	-0.574*(0.299)
Change in Electricity consumed by households(t-2)	0.418*(0.200)
Change in GDP	-0.248(0.219)
Change in GDP(t-1)	0.282*(0.154)
Change in Price of electricity	0.027(0.020)
Change in Price of electricity(t-1)	-0.018(0.012)
Change in Urbanization rate	-0.018(0.019)
Change in Urbanization rate(t-1)	-0.071**(0.027)
Change in Hydro inflows	0.078***(0.015)
Change in Hydro inflows (t-1)	0.030**(0.015)
Reform	-0.018(0.014)
Connections	0.137**(0.035)
ECT	-0.233***(0.023)
Long run	
GDP	1.285***(0.118)
Price of electricity	-0.065(0.101)
Urbanization rate	0.459**(0.152)
Hydro Inflows	0.617*(0.334)
Constant	-35.730(4.560)

Source: Author's estimates from KPLC, KNBS, World Bank and KenGen data.

Notes:*** indicates significance at 1% level,** indicates significance at 5% level,* indicates significane at 10% level. Standard error are in paranthesis.

[4] The selected model ARDL (3, 2, 2, 2, 2) had several lags hence the reason for the many results in the short run.

Table 2.15 shows ARDL estimation results of the elasticities of household demand for electricity in Kenya. Elasticities in the short run were smaller than in the long run. This can be attributed to the minimal flexibility in demand associated with the short run. The error correction term was negative and significant indicating convergence to equilibrium in the long run. A deviation of 1% from the long run equilibrium was corrected by 23% annually.

In the short run, a rise in GDP of 1% increased household electricity demand by 0.299% in the next period. A change in GDP of 1% also increased household electricity demand with 0.282% in the subsequent period. In the long run, GDP representing income, was found to be elastic. A 1% increase in income resulted in a 1.28% increase in household electricity demand. This finding is consistent with economic theory and confirms that household electricity demand behaves like a normal good, increasing with income. Similar results were reported for Nigeria by Babatunde and Shuaibu (2009) and for Turkey by Dilaver and Hunt (2010a). The finding of income elastic electricity demand was consistent with Bhattacharyya (2011) observation that developing countries tend to have income elastic electricity demand.

A1% increase in hydro inflows increased electricity demand by 0.14% in the next period in the short run. A change in hydro inflows of 1% increased electricity demand by 0.078% in the current period. A similar change in hydro flows increased electricity demand by 0.03% in the subsequent period. In the long run, 1% increase in hydro inflows increased electricity demand by 0.62%. The result indicated supply side constraints affected household electricity demand and could signify the presence of unmet demand in the electricity market. This finding is a contribution to literature.

Urbanization was found to have a positive and statistically significant effect on household electricity demand. An increase in urbanization rate of 1% increased household electricity demand by 0.107% in the subsequent period. A similar result was reported by Guta et al (2015) in a study for Ethiopia. In the long run, an increase in urbanization rate of 1% increased the household electricity demand by 0.45%.

The reforms that followed the political regime change in 2002 were found to positively impact on household electricity demand increasing it by 0.14%. The reforms introduced change management that improved the performance at KPLC, accelerated electrification strategies that mainly benefited domestic consumers and introduced a life tariff for low income households. The reforms also allowed for institutional reforms that improved the sector performance in meeting customer needs, these included, establishment of new institutions in the sector, initial public offering of KenGen and procurement of more independent power producers to bridge the supply gap (Godinho and Eberhard, 2019). The reforms of 1998 negatively affected the household demand, decreasing it by 0.018%. This was as earlier explained attributable to the drought and economic recession that followed the reform period.

Commercial and industrial demand for electricity in Kenya

Following Cebule and Herder (2010) the commercial and industrial electricity demand was specified as

$$CIE = f(Y, P_e\ , P_d, EF_{ic}, H, C_{ic}, D_1) \qquad 2.16$$

where CIE was the electricity consumed by the commercial and industrial consumers, Y was income, P_e was electricity price, P_d was price of the alternative fuel (Diesel), EF_{ic} was efficiency levels in production, H was hydro inflows and C_{ic} was the number of commercial and industrial consumers. D_1 was a dummy variable to correct for structural breaks associated with reforms of 1998.

Rewriting equation 2.16 as in Cebule and Herder (2010) and Ghaderi et al. (2006b)

$$CIE_t = e^{\alpha} P_{et}^{a}\ P_{dt}^{b}\ EF_{ict}^{c}\ H_t^{d}\ \ C_{ict}^{e}, Y_t{}^{f}\ \ e^{gD_1}\ e^{\varepsilon_t} \qquad 2.17$$

where α, a, b, c, d, e, f and g were coefficients to be estimated, ε was the error term and t was time period.

The log linear form of equation 2.17 was specified as

$$lnCIE_t = \alpha + alnP_{et} + blnP_{dt} + clnEF_{ict} + dlnH_t + elnC_{ict} + flnY_t + gD_1 + \varepsilon_t \qquad 2.18$$

Equation 2.18, the error correction model took the following form;

$$\Delta ln\ CIE_t = \alpha + \sum_{i=1}^{n} \beta_i \Delta ln\ CIE_{t-i} + \sum_{i=0}^{n} a_i \Delta ln\ P_{et-i} + \sum_{i=0}^{n} b_i \Delta ln\ P_{dt-i} + \sum_{i=o}^{n} c_i \Delta\ lnEF_{ict-i} + \sum_{i=0}^{n} d_i \Delta\ lnH_{t-i} + \sum_{i=0}^{n} e_i \Delta\ lnC_{ict-i} + \sum_{i=0}^{n} f_i\ \Delta lnY_{t-i} + \emptyset_1 ln\ CIE_{t-1} + \emptyset_2 ln\ P_{et-1} + \emptyset_3 ln\ P_{dt-1} + \emptyset_4 lnEF_{ict-1} + \emptyset_5 lnH_{t-1} + \emptyset_6 lnC_{ict-1} + \emptyset_7 lnY_{t-1} + gD_1 + \varepsilon_t \qquad 2.19$$

where β_i, a_i, b_i, c_i, d_i , e_i, f_i and g were short run coefficients and $\emptyset_1 \dots . \emptyset_7$ were long run coefficients. Equation 2.19 was estimated using the ARDL method.

Data and measurement

The data used in the analysis was for the period 1985-2016 sourced from KPLC annual reports, Kenya National Bureau of Statistics Economic Surveys and Statistical Abstracts, World Bank, World Development Indicators and KenGen.

Table 2.16: Definition and measurement of variables used to estimate commercial and industrial electricity demand in Kenya.

Variable	Definition and measurement	Source of variable and data
CIE	Annual electricity sales to commercial and industrial consumers (GWh)	Dilaver and Hunt (2010b), KPLC annual reports, various
P_e	Real price of electricity (Ksh/200kWh) based period February 2009.	Dilaver and Hunt (2010b) KNBS statistical abstracts, various
P_d,	Annual diesel Price per litre (Ksh/) base period February 2009.	Ghader et al. (2006) KNBS statistical abstracts, various
EF_{ic}	Computed by dividing the annual value added produced by industry with the annual electricity sales to commercial and industry (Ksh/kWh).	Cebule and Herder (2010) The value added produced from Industry was collected from world bank statistics, World Development Indicators. Electrical energy consumed by industry was collected from KPLC annual reports
H	Total annual hydro inflows (Cumecs).	This was introduced to test for effects of supply side constraints on demand Data collected from KenGen
Y	Annual constant gross value added in Ksh	Dilaver and Hunt (2010b), Bernstein and Madlener (2010), Bjørner and Togeby (1999) and Bhattacharyya (2011) World Bank statistics, World Development Indicators
C_{ic}	Number of commercial and industrial customers as reported in KPLC annual reports	Ghader et al. (2006) KPLC annual reports, various
D_1	1985 - 1997 = 0 and 1998 – 2015=1	Dummy variable to correct for structural breaks and captures the first sector reforms.

Source: Author

Empirical results and discussion

Table 2.17: Summary statistics of variables used in the analysis of commercial and industrial electricity demand.

Variable	Unit	Mean	Std. deviation	Min	Max
Commercial and industrial electricity consumption	GWh	2941	1148	1476	5362
Number of customers	No.	136122	83679	38695	324801
Diesel price	Kshs/Liter	66	47	9	148
Energy Efficiency	Kshs/kWh	158	14	139	187
Output	Kshs trillion illion	2.12	0.72	1.18	3.81
Hydro inflows	Cumecs	862	262	466	1559
Price of Electricity	Kshs/200kWh	56	44	7	138

Source: Author's computation from KPLC, KNBS, World Bank and KenGen data.

Table 2.17 provides the summary statistics of the data before the logarithmic transformation. Price of electricity, hydro inflows and diesel prices statistics are as earlier discussed in the aggregate demand section. Commercial and industrial consumption averaged 2,941GWh increasing from 1,476GWh in 1985 to 5,362GWh in 2016. The number of customers averaged 136,122. Despite the high consumption compared to household consumers, the number of customers is much lower, about a seventh of the number of domestic consumers indicating high consumption level per customer. The consumption was about three times that of domestic consumers. Commercial and industrial customers are the largest consumers of electrical energy (Republic of Kenya, 2018b; Lahmeyer, International. GmbH, 2016). Energy efficiency averaged Ksh 158/kWh. The highest efficiency level of kshs187/kWh was realised in 2000/2001 a period that was marked with drought that affected electricity demand due to power rationing (Republic of Kenya, 2004). The gross value-added representing income/output averaged Ksh 2,117 billion having increased from Kshs 1,178 billion in 1985 to Kshs 3,809 billion in 2016.

Figure A-3 in Appendix 1 provides the graphical presentation of the variables used in the analysis. Hydro inflows, energy efficiency and sales demonstrated potential of having structural breaks. The summary statistics for the logged variables used in the analysis of commercial and industrial electricity demand are presented in Tables A.7.

The correlation matrix is presented in Table A.8 in Appendix 1. The results indicated high correlation between the variables. This necessitated a multi-collinearity test to test for collinearity. Coefficient variance decomposition test confirmed the presence of multi-collinearity. Several estimates were undertaken to identify the model that best represented the data and reduced the multi-collinearity problem. The model that dropped number of customers and diesel price reduced the collinearity problem and represented our model and the available data best. The coefficient variance decomposition results are provided in Table A.9 in Appendix 1.

Diagnostic tests
Unit root tests

Table 2.18:Unit root test for variables used to estimate commercial and industrial electricity demand

Variable	ADF	PP	KPSS	Breakpoint	Conclusion
Y_t- Intercept	1.68609	1.483354	0.750741	-0.991863	The series are stationary at level at 10% level of significance based on the breakpoint unit root test-additive outlier;[5] Intercept and Trend –Trend only.
Intercept and Trend	0.213038	-0.062031	0.170762	-4.120171	
H_t - Intercept	-4.789928	-3.973428	0.316628	-6.210899	The series are stationary at level at 1% level of significance based on the ADF, PP and breakpoint unit root test.
Intercept and Trend	-5.314256	-6.277660	0.286215	-6.098086	
P_t- Intercept	-1.254885	-1.254885	0.71490	-2.677943	The series are stationary at level at 1% level of significance based on the breakpoint unit root test; Intercept and Trend - Intercept only.
Intercept and Trend	-2.386906	-2.395306	0.140567	-6.76245	
CIE_t - Intercept	-0.232092	-0.307148	0.703010	-3.741512	The series are stationary at level at 1% level of significance based on the breakpoint unit root test; Intercept and Trend - Intercept only.
Intercept and Trend	-2.227625	-1.592545	0.122848	-6.006354	
EF_{ict} - Intercept	-2.292749	-2.072178	0.367648	-4.126277	The series are stationary at level at 1% level of significance based on the breakpoint unit root test; Intercept and Trend - Intercept only.
Intercept and Trend	-2.764195	-2.085908	0.059408	-5.850523	

Source: Author's estimates from KPLC, Economic surveys, World Bank statistics and KenGen data.

Critical levels 1%, 5%, and 10% significance levels are as follows; Intercept ADF(-3.662,-2.960,-2.619), PP (-3.661661,-2.960411,-2.619160), KPSS (0.739000, 0.463000, 0.347000), Break point (-4.949133, -4.443649, -4.193627) Intercept and Trend ADF(-4.309824, -3.574244, -3.221728) PP (-4.296729, -3.568379, -3.218382), KPSS (0.216000, 0.146000, 0.119000) break point; (-5.347598, -4.859812, -4.607324 – Intercept only; -5.719131, -5.17571, -4.89395 - Trend and intercept; -5.067425, -4.524826, -4.261048- trend only)

[5] Test critical values are: 1% level (-4.909873), 5% level (-4.363511) and 10% level (-4.085065)

The unit roots test detailed in Table 2.18 indicated that the variables were stationary at level and hence I (0). As indicated in Pesaran et al. (2001), this means we could proceed estimating using the ARDL model which requires the variables to be I (0) or I (1). Structural breaks with respect to the energy efficiency, hydro inflows and sales occurred in 1998. This was corrected by including the dummy variable reform.

Model selection

The Lag length 3 model failed most of the residual and stability diagnostic tests. The no intercept no trend model failed the normality and CUSUM of squares test. The Intercept and no trend model and the intercept with trend model failed the LM serial correlation test. Lag length 2 no intercept no trend model failed the Heteroskedasticity residual diagnostic test while the intercept with trend model failed the CUSUM stability test. The model that passed all the test was ARDL (2, 2, 0, 1, 2) with a constant and no trend. Table 2.19 presents the model selection results.

Table 2.19: Commercial and industrial electricity demand model selection results

Model	Akaike information criterion
ARDL (2, 2, 0, 1, 2)	-6.827204
ARDL (2, 2, 1, 1, 2)	-6.761869
ARDL (2, 2, 0, 2, 2)	-6.760603
ARDL (2, 2, 1, 2, 2)	-6.695288

Source: Author’s estimates from KPLC, Economic surveys, World Bank statistics and KenGen data.

Residual and Stability tests

Table 2.20: Diagnostic stability test results for commercial and industrial electricity demand

Description	LM serial correlation	Normality	Heteroskedasticity	CUSUM and CUSUM of squares	Conclusion
Intercept and no trend model	0.4686	0.6192	0.3375	within the confines of the 5% significance	Diagnostic tests passed

Source: Author’s estimates from KPLC, Economic surveys, World Bank statistics and KenGen data.

The constant and no trend ARDL model passed all the residual and stability diagnostic tests as in Table 2.20 and was used to test for the existence of a long-run relationship.

Cointegration test

Table 2.21:Cointegration results for commercial and industrial demand

Description	Critical Values		F statistics	Conclusion
Restricted intercept no trend	I (0)	I (1)	12.78	Long run relationship exists
	2.2 (10%)	3.09(10%)		
	2.56(5%)	3.49(5%)		
	3.29(1%)	4.37(1%)		

Source: Author’s estimates from KPLC, Economic surveys, World Bank statistics and KenGen data.

The cointegration test results are provided in Table 2.21. The ARDL Bounds cointegration test found an existing long-run relationship between commercial and industrial electricity demand on one part and income, electricity price, industry efficiency, hydro inflows, connections and reforms on the other.

Determinants of commercial and industrial demand for electricity in Kenya

Table 2.22: ARDL estimates of elasticities of demand for commercial and industrial electricity in Kenya

Variable	Coefficient
Short run estimates	
C	-14.301 (2.096)
Commercial and industrial Electricity consumption(t-1)	-0.750*** (0.114)
Energy Efficiency (t-1)	-0.734*** (0.134)
Output (t-1)	0.847*** (0.128)
Hydro inflows	0.011* (0.006)
Price of Electricity(t-1)	-0.022** (0.008)
Change in Commercial and industrial Electricity consumption(t-1)	0.614*** (0.135)
Change in Energy Efficiency	-0.972*** (0.039)
Change in Energy Efficiency(t-1)	0.572*** (0.147)
Change in Output	1.054*** (0.071)
Change in Output(t-1)	-0.669*** (0.152)
Change in Price of Electricity	-0.003 (0.007)
Reform	-0.054*** 0.008
ECT	-0.750*** (0.075)
Long run estimates	
Energy Efficiency	-0.979*** (0.045)
Output	1.129*** (0.022)
Hydro inflows	0.015* (0.008)
Price of Electricity	-0.030*** (0.008)
Constant	-19.061 (0.744)

Source: Author’s estimates from KPLC, KNBS, World Bank and KenGen data.

Notes: *** indicates significance at 1% level; ** indicates significance at 5% level; * indicates significance at 10% level. The standard errors are in paranthesis.

The estimated short and long run elasticities of demand are presented in Table 2.22. The estimated coefficient had the expected signs and were consistent with economic theory that stipulates demand to be a factor of price and income. The short run elasticities were smaller than the long run. This is due to the time taken to make any adjustment to electricity consumption in the short run. The error correction term was significant and negative indicating convergence to the equilibrium.

In the short run, an increase in income by 1% increased electricity consumption in the next period by 0.84%. A 1% change in income increased electricity demand with 1.05%. This can be attributed to the need for more energy to produce the extra units of outputs, of which in the short run period, alternative inputs into the production process may be difficult for the firms to adopt. However, a 1% change in income in the previous period is likely to decrease electricity demand in the current period by 0.67%. This could be as a result of consumers having a one-year period to make changes into their production processes. In the long run, commercial and industrial electricity demand is income elastic. A 1% increase in income increased electricity consumed by commercial and industrial consumers by 1.13%. This finding is similar to that of Cebule and Herder (2010) that found an income elasticity of electricity demand of 1.57 in the USA. Other studies that found electricity demand for commercial and industrial electricity consumers to be positively affected by the level of economic activity include Dilaver and Hunt (2010b) in a study for Turkey and Ghaderi et al. (2006b) in a study for Iran.

Electricity demand was found to be price inelastic in the short and long run. In the short run a 1% increase in the price of electricity decreased electricity demand by 0.02% in the subsequent period. In the long run, a 1% increase in the price of electricity decreased electricity demand by 0.03%. The negative relationship between price and demand is consistent with demand theory for a normal good. Inelastic electricity demand with respect to price was also found by Cebule and Herder (2010) study for the US, Bjorner and Togeby (1999) study for Denmark, Dilaver and Hunt (2010b) study for Turkey and Bianco et al. (2010) study for Romania.

The study also found efficiency to be significant determinants of demand in the short and long run. In the short run, 1% increase in energy efficiency reduced electricity demand in the next period by 0.73%. A 1% change in energy efficiency decreased electricity demand by 0.97% in the current period but increased electricity demand by 0.57% in the subsequent period. In the long run, a 1% increase in energy efficiency decreased electricity demand with 0.98%. This finding is consistent with that of Cebule and Herder (2010) in a study for commercial and industrial electricity consumers in USA.

Another significant determinant of commercial and industrial electricity demand was hydro inflows, as a proxy for supply side constraints. In the in short run, a 1% increase in hydro inflows increased electricity demand by 0.01%. In the long run a 1% increase in the hydro inflows increased demand for electricity by 0.015%. None of the studies reviewed had included a variable for supply side constraints in their analysis. This finding is therefore a contribution to literature.

The reforms of 1998 were found to negatively affect electricity demand. This was as earlier explained attributable to the coinciding of the reforms with the worst drought since the period 1947 to 1949 (Republic of Kenya, 2004). Previous period demand also negatively affected demand in the short run. A 1% increase in previous period demand decreased demand in the current period with 0.75%. This indicates that commercial and industrial consumers are likely to reduce their demand in the current period based on their previous period demand.

Forecast of aggregate demand for electricity in Kenya to 2035

The demand for electricity in Kenya to the year 2035 was projected in three scenarios viz., the low or pessimistic demand, the medium or reference demand and the high or optimistic demand. The three scenario were in line with Adom and Bekoe (2012), Dilaver and Hunt (2010a), Amarawickrama and Hunt (2007), Ghaderi et al. (2006a) and the official sector projection by Lahmeyer international GmbH (2016) and Republic of Kenya (2013). The projections period of upto 2035 was informed by the official forecast year in Lahmeyer international GmbH (2016). Previous official forecast by the government had the forecast year being 2033 (Republic of Kenya, 2013b).

The simulation was done using Eviews 10 software and the ARDL estimates of the aggregate demand model in equation 2.8. The sample size was resized to the year 2035 and forecast values for the independent variables included in the model. The model was re-estimated and the forecast values of demand as the dependent variable determined. The forecast assumptions for the independent variables are detailed in Table 2.23.

Table 2.23 : Assumptions made in forecasting aggregate demand for electricity in Kenya to 2035[6]

Variable	Optimistic scenario Assumptions (High)	Reference scenario Assumptions (Reference)	Pessimistic scenario Assumptions (Low)
GDP	The projected GDP growths are 8.1% in 2018, 8.7% in 2019 and 9.5% in 2020, this growth is maintained for the remainder of the forecast period The projections are in line with the vision 2030 projections in the Kenya Economic Report (Kenya institute for public policy research and analysis (KIPPRA), 2017)	The projected GDP growths are 6.4 in 2018, 6.5 in 2019 and 6.7 in 2020, this growth is maintained for the remainder of the forecast period. Assumed the baseline projections in the Kenya Economic Report (KIPPRA, 2017)	The projected GDP growths are 6.0% in 2018, 6.1% in 2019 and 6.1 in 2020, this growth is maintained for the remainder of the forecast period. Assumed the low projections in the Kenya economic report (KIPPRA, 2017)
Price of electricity	The electricity tariff was assumed to reduce from 15.56KSh/kWh in 2016 to 10.45KSh/kWh in 2035 as proposed by the investment prospectus 2013-2016 (Republic of Kenya, 2013a)	Retail tariff was assumed to increase from 15.56KSh/kWh in 2016 to 16.33KSh/kWh in 2035, the highest recorded in the available data from 1985.	The forecast assumed retail tariffs to increase from 15.56 Ksh/kWh in 2016 to 24.64 Ksh/KWh by the year 2024. This was as projected by the government based on the committed generation projects (Republic of Kenya 2018c). The retail tariff was assumed to remain the same for the remainder of the forecast period
Hydro inflows	Hydro inflows were assumed to increase until they reached 2499 Cumecs. This is the highest inflows recorded in the el-nino period of 2012/13.	The inflows were assumed to decline from KenGen's estimates of 1053 Cumecs in 2018 to the 35-year average inflows of 857 Cumecs by the year 2035.	Assumed the hydro inflows decreased until they reached 466 Cumecs. This is the least inflows realised in drought period of 2008/09.
Diesel price	The fuel prices forecast were based on the generation and transmission master plan that projected the fuel price to increase at an average rate of 3.69% (Lahmeyer international GmbH, 2016).		

Source: Author's compilation from KIPPRA, KenGen, Republic of Kenya (2013a, 2018c) and Lahmeyer international GmbH (2016) data

[6] As suggested by Bhattacharyya (2011), forecasting the variables was based on judgements, indicators and trend analysis. For this reason, some of the variables remained constant for the period beyond which the indicators were available. This approach has also been used in the official forecast (Lahmeyer international GmbH, 2016; Republic of Kenya, 2013).

In the low demand scenario, the demand was projected to rise from 7,811GWh in 2017 to 18,324GWh by 2035 representing an average growth rate of 4.8%. In the reference scenario, electricity demand was projected to rise from 7,811GWh in 2017 to 21,655GWh by 2035 representing an average growth rate of 6%. In the high demand scenario, the demand was projected to grow from 7,811GWh in 2017 to 31,735GWh by 2035 representing an average growth rate of 8%. The forecasts are illustrated in Figure 2.1 and Table 2.24.

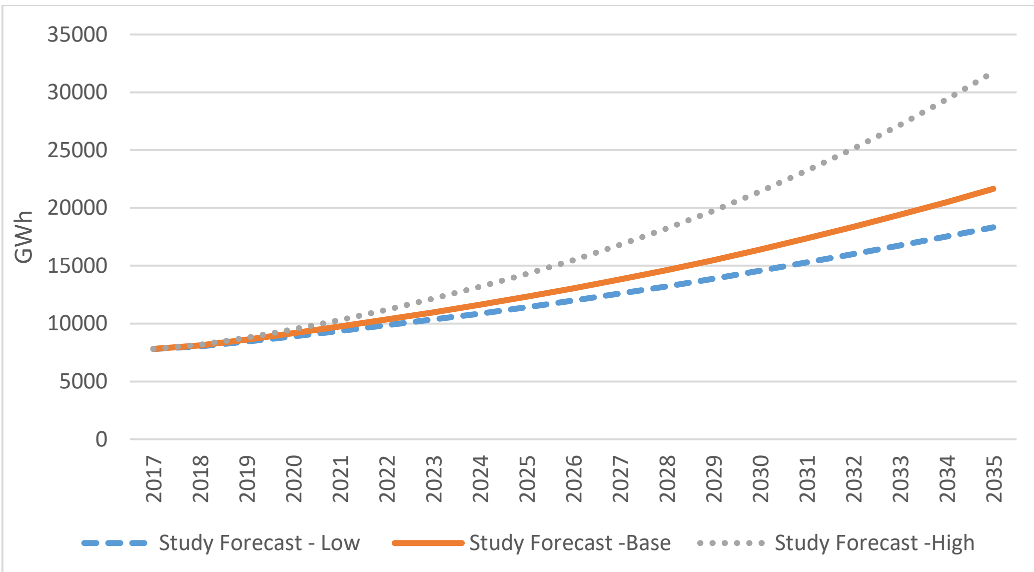

Figure 2.1: Electricity demand forecast for Kenya to 2035

Source: Author's estimates from KPLC, KNBS, World Bank and KenGen data.

Table 2.24: Eviews forecast of Electricity demand forecasts in Kenya to 2035

Year	Scenario1: Low demand	Scenario2: Reference demand	Scenario3: High demand
2017	7811	7811	7811
2018	8039	8122	8176
2019	8450	8620	8777
2020	8902	9164	9499
2021	9368	9749	10319
2022	9849	10347	11199
2023	10351	10970	12150
2024	10868	11624	13178
2025	11414	12313	14291
2026	11989	13041	15496
2027	12593	13811	16801
2028	13226	14627	18216
2029	13888	15489	19749
2030	14580	16403	21409
2031	15283	17369	23206
2032	16005	18366	25118
2033	16751	19408	27170
2034	17524	20503	29378
2035	18324	21655	31735

Source: Author's estimates from KPLC, KNBS, World Bank and KenGen data.

Comparison of study forecasts with government forecasts

The official government forecasts of electricity demand in Kenya are contained in the Generation and Transmission Master Plan (Lahmeyer International GmbH, 2016) and the least cost power development plan 2013 – 2033 (Republic of Kenya, 2013b). Amongst the variables used in forecasting, only GDP was common between the official forecast and this study forecast. A comparison of the GDP assumptions indicates minimal difference in the assumption between the Lahmeyer International GmbH (2016) and this study assumption. Lahmeyer International GmbH (2016) assumed an annual average GDP growth rate of 6.9% for the reference case, 5.1% for the low case and 10% for the period beyond 2020 for the vision case. Republic of Kenya, (2013b) study assumed annual GDP growth rates of 6% for the low case, 10% for the base case and 12% for the high case (Republic of Kenya, 2013b). Both Lahmeyer International GmbH (2016) and Republic of Kenya (2013b) included unmet demand in their forecasting. There assumption for the unmet demand forecast was based on a percentage of consumption. This study has used hydro inflows as a proxy for supply side constraints that could result in unmet demand.

As shown in Table 2.25, Figures 2.2, 2.3 and 2.4 this study forecast compares closely with Lahmeyer International GmbH (2016). The Lahmeyer International GmbH (2016) forecast is however slightly higher in all the three scenarios with this study reference scenario forecast almost matching the low scenario and the high scenario the reference scenario. The forecast in Republic of Kenya (2013b) is much higher. The forecast was over six times the forecast in this study at 81,352 GWh in the reference scenario. Thus, the official forecast is overstated. This is can be attributed to the different methodologies being used to forecast the demand. The official forecast used an excel based end use model which attempts to forecast the demand based on the end uses of energy. However, this methodology requires a lot of base data that may not be available. Lahmeyer International GmbH (2016) alluded to having resulted to assumptions based on less reliable data or more general and deduced assumptions. This is unlikely with the aggregated approach used in this study as the historical data is already available. Amarawickrama and Hunt (2007) and Inglesi and Pouris (2010) also attribute the deviation between their own and official forecasts to government use of end user model in the forecast and non-inclusion of price. Due to the difference in the two approaches, International Atomic Energy Agency (1988) recommends the use of the two methods in parallel as they supplement each other. Other studies that found the official forecast to be overstated include Erdogdu (2007) in Turkey, Amarawickrama and Hunt (2007) in Sri-lanka and Inglesi and Pouris (2010) in South Africa.

Table 2.25: Comparison of study forecast with other forecasts

Year	Low scenario			Reference scenario			High scenario		
	Study Forecast	Lahmeyer Inter	Republic of Kenya	Study Forecast	Lahmeyer Inter.	Republic of Kenya	Study Forecast	Lahmeyer Inter	Republic of Kenya
2017	7811	10670	13989	7811	10821	15678	7811	11965	16740
2018	8039	11298	15275	8122	11594	17719	8176	13295	19282
2019	8450	11932	16689	8620	12421	20042	8777	14736	22236
2020	8902	12632	18242	9164	13367	22686	9499	16665	25671
2021	9368	13409	19941	9749	14432	25687	10319	17995	29657
2022	9849	14110	21847	10347	15466	29150	11199	19421	34357
2023	10351	14838	23933	10970	16553	33088	12150	21341	39827
2024	10868	15610	26229	11624	17697	37578	13178	23170	46208
2025	11414	16427	28754	12313	19240	42698	14291	25469	53657
2026	11989	17296	31532	13041	20575	48536	15496	27657	62355
2027	12593	18222	34588	13811	21981	55196	16801	30015	72515
2028	13226	19208	37951	14627	23716	62793	18216	32622	84389
2029	13888	20258	41651	15489	25355	71461	19749	35407	98270
2030	14580	21375	45723	16403	27366	81352	21409	39260	114502
2031	15283	22565	50204	17369	29304	92641	23206	42550	133492
2032	16005	23834	55135	18366	31375	105527	25118	46077	155712
2033	16751	25193	59135	19408	33586	118680	27170	49922	179850
2034	17524	26648		20503	35950		29378	54108	
2035	18324	28153		21655	38478		31735	58679	
Average growth rate (%)	4.80	5.60	9.50	5.70	7.30	13.50	7.90%	9.40	16.0

Source: Author's compilation from own forecast, Lahmeyer International GmbH (2016) forecast and Republic of Kenya (2013b) forecast.

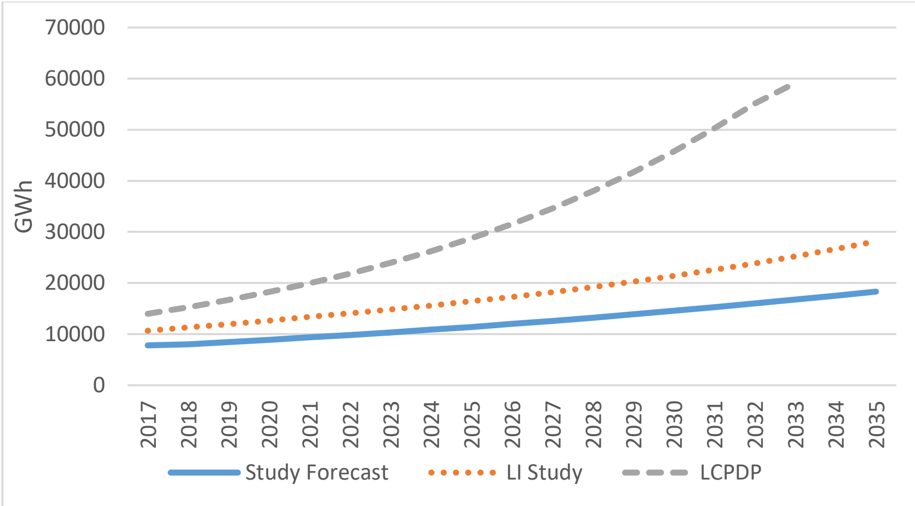

Figure 2.2: Comparison of study forecast with other forecasts – Low

Source: Author’s compilation from own forecast, Lahmeyer International GmbH (2016) forecast and Republic of Kenya (2013b) forecast.

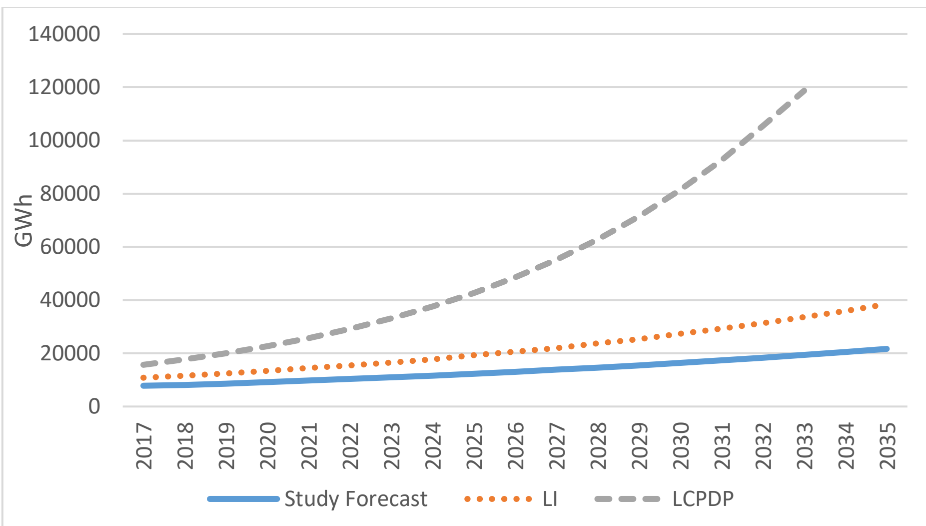

Figure 2.3: Comparison of study forecast with other forecasts – reference

Source: Author’s compilation from own forecast, Lahmeyer International GmbH (2016) forecast and Republic of Kenya (2013b) forecast.

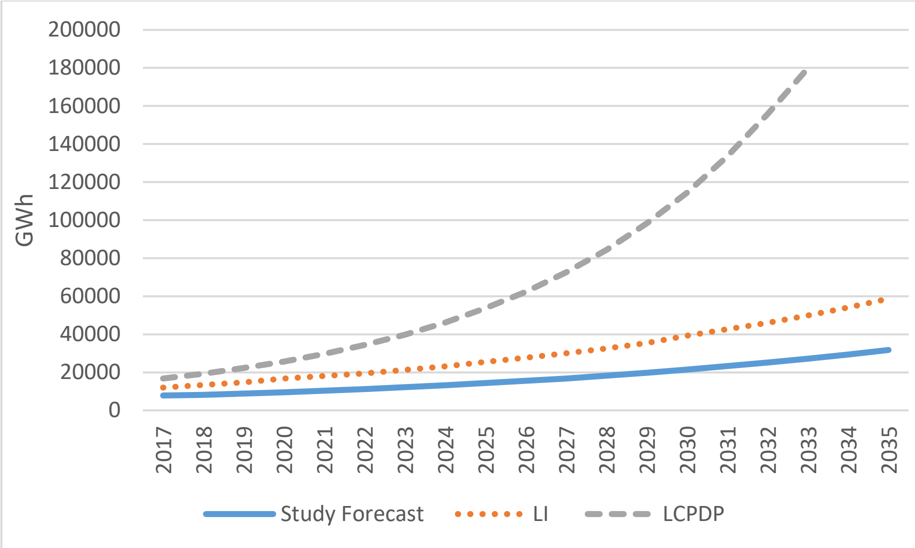

Figure 2.4: Comparison of study forecast with other forecasts – high

Source: Author's compilation from own forecast, Lahmeyer International GmbH (2016) forecast and Republic of Kenya (2013b) forecast.

Household, commercial and industrial demand for electricity forecasts

The forecast of household, commercial and industrial demand for electricity were undertaken to assess the contribution of either sector to aggregate demand. Forecasting followed the similar steps undertaken in forecasting aggregate demand. Tables 2.26 provides the assumptions used in undertaking the forecasts.

Table 2.26: Assumptions in forecasting household, commercial and industrial demand for electricity in Kenya to 2035

Variable	Optimistic scenario assumption(high)	Reference scenario assumption (reference)	Pessimistic scenario assumption (low)
Price of electricity	The electricity tariff was assumed to reduce from 15.56KSh/kWh in 2016 to 10.45KSh/kWh in 2035 as proposed by the investment prospectus 2013-2016 (Republic of Kenya, 2013a)	The retail tariff was projected to increase from 15.56KSh/kWh in 2016 to 16.33KSh/kWh in 2035, the highest recorded average tariff in the study period 1985 to 2016 collected from KPLC annual reports.	The retail tariff was projected to increase from 15.56 KSh/kWh in 2016 to 24.64 KSh/KWh by the year 2024. This is as projected in Republic of Kenya (2018c). The retail tariff was assumed to remain the same for the remainder of the forecast period
Hydro inflows	Assumed hydro inflows to increase until they reached 2499 Cumecs, the highest inflows recorded in the el-nino period of 2012/13.	The inflows were assumed to decline from KenGen's estimates of 1053 Cumecs in 2018 to the 35-year average inflows of 857 Cumecs by the year 2035.	Assumed the hydro inflows will decrease until they reach 466 Cumecs, this is the least inflows realised in the drought period of 2008/09.
GDP	The projected GDP growths were 5.5% in 2018, 5.96% in 2019 and 6.51% in 2020, this growth was maintained for the remainder of the forecast period. The projected growth rates in the Kenya economic report were adjusted (KIPPRA, 2017) by multiplying with 68.55%. This is the average ratio of the private consumption expenditure to the total gross domestic expenditure, over the period 2013 to 2017 constant prices.	The projected GDP growths were 4.39% in 2018, 4.46% in 2019 and 4.59% in 2020, this growth was maintained for the remainder of the forecast period. Assumed the baseline projections in the Kenya Economic Report (KIPPRA, 2017). Similar adjustment to the high scenario was done.	A GDP growth rate of 4.11% was assumed for the forecasting period. Assumed the low projections in the Kenya economic report (KIPPRA, 2017) with an adjustment similar to high and reference scenario.
Urbanization rate	Projections were based on the world urbanisation prospects (United Nations, 2018). The projections were 4.23% for 2015-2020, 4.09% for 2020-2025, 3.95% for 2025-2030 and 3.77% for 2030-2035.		
Gross Value added	The growth rate projections were 7.13% in 2018, 7.66% in 2019 and 8.36% in 2020 and the remainder of the forecast period. Assumed the vision 2030 projections in the Kenya Economic Report (KIPPRA,	The projected growths rates were 5.63% in 2018, 5.72% in 2019 and 5.9% in 2020 and for the rest of the forecast period. Assumed the baseline projections in the Kenya Economic Report (KIPPRA, 2017). An adjustment similar to the	The assumed growth rates were 5.28% in 2018 and 5.37% for the remainder of the forecasting period. Assumed the low projections in the Kenya economic report (KIPPRA, 2017). Similar adjustment to high and reference scenario was

Variable	Optimistic scenario assumption(high)	Reference scenario assumption (reference)	Pessimistic scenario assumption (low)
	2017). The projected GDP growths were adjusted to exclude the contribution of taxes, whose contribution was 12% in 2017 (KNBS, 2018).	high scenario was undertaken.	undertaken.
Energy Efficiency	Energy efficiency growth rates for the three scenarios were based on the energy saving rate projections for industry, commercial and institutional sectors in the generation and transmission masterplan. The rates were 8% for 2018 – 2021, 4% for 2022- 2024, 2% for 2025-2027, 2.4% for 2028-2033 and 1.4% 2034- 2035 (Lahmeyer International GmbH., 2016).		

Source: Author's compilation from Republic of Kenya (2013a, 2018c), KNBS, KenGen, Lahmeyer International GmbH (2016) and United Nations statistics

The forecasts for household, commercial and industrial consumers are presented in Table 2.27. There was minimal increase in demand in the initial years for commercial and industrial consumers. This is because efficiency levels were projected to be high in the initial years as commercial and industrial customers adopt energy efficiency measures (Lahmeyer International GmbH, 2016). The growth rate in household electricity demand was slightly higher than that of commercial and industrial consumers averaging 6% in the base scenario compared to the 4% in the commercial and industrial consumers, this could be attributed to increased connection rates amongst the household and growth in incomes.

Table 2.27: Eviews forecast of household, commercial and industrial demand for electricity in Kenya up to 2035

Year	Commercial and industrial			Household		
	Low Scenario	Base Scenario	High Scenario	Low Scenario	Base Scenario	High Scenario
2018	5559	5611	5692	2260	2327	2331
2019	5516	5603	5805	2375	2489	2510
2020	5465	5607	5969	2477	2654	2715
2021	5420	5612	6145	2576	2826	2948
2022	5590	5836	6575	2677	3002	3205
2023	5747	6051	7016	2775	3183	3488
2024	5899	6266	7477	2880	3370	3799
2025	6165	6612	8122	2974	3567	4144
2026	6440	6966	8806	3062	3765	4511
2027	6725	7332	9540	3152	3973	4913
2028	6995	7685	10291	3244	4191	5352
2029	7277	8056	11103	3336	4420	5832
2030	7571	8445	11980	3432	4666	6362
2031	7876	8853	12926	3521	4916	6926
2032	8193	9281	13947	3609	5178	7539
2033	8522	9730	15049	3695	5454	8206
2034	8951	10302	16399	3778	5745	8930
2035	9393	10899	17837	3863	6058	9699
Average Growth Rate	3%	4%	7%	3%	6%	8%

Source: Author's estimates from Republic of Kenya, KNBS, KenGen, Lahmeyer International GmbH (2016) and United Nations (2018)

Commercial and industrial consumers were projected to remain the highest consumers of electricity as is the case currently. However, their contribution is forecasted to decrease with time as presented in Table 2.28, this can be attributed to the projected increase in energy efficiency. This finding is consistent with that of Lahmeyer International GmbH (2016). The changes in the share of household demand is minimal in both Lahmeyer

International GmbH (2016) and this study. Households, commercial and industrial consumers will continue being the drivers of electricity demand.

Table 2.28: Projected contribution of households, commercial and industrial demand to total electricity demand in Kenya to 2035 (Percentage)

Year	Commercial and industrial demand Study Forecast	Household demand Study Forecast	Commercial and industrial demand Lahmeyer forecast	Household demand Lahmeyer forecast
2018	69.3	28.4	53.1	26.6
2019	65.5	28.5	52.0	27.3
2020	61.8	28.5	50.7	27.6
2021	58.3	28.4	50.0	27.8
2022	57.3	28.3	49.5	28.1
2023	56.1	28.2	48.8	28.1
2024	55.0	28.1	48.2	28.3
2025	54.8	28.0	47.2	28.3
2026	54.7	27.8	46.7	28.5
2027	54.4	27.7	46.2	28.7
2028	54.0	27.5	45.5	28.9
2029	53.5	27.4	45.0	29.2
2030	53.1	27.2	44.1	29.2
2031	52.7	27.1	43.6	29.5
2032	52.4	26.9	43.1	29.9
2033	52.1	26.8	42.6	30.2
2034	52.4	26.7	42.2	30.6
2035	52.6	26.5	41.7	30.9

Source: Author's compilation from own forecast and Lahmeyer International GmbH (2016) forecast

2.3 **Summary and Conclusions**

The study sought to estimate demand for electricity in Kenya and make forecasts to year 2035. The forecast was then compared with the official forecast. Three models were estimated namely, the aggregate, the residential, the commercial and industrial demand. Household, commercial and industrial demand forecasts were also undertaken to establish their contribution to the demand.

The results showed the key drivers of aggregate demand in the short run were lagged electricity demand, lagged hydro inflows, GDP, lagged diesel prices, connections and reforms. In the long run hydro inflows, GDP and diesel price drive demand. The drivers of residential electricity demand in the short run included: lagged electricity demand, lagged GDP, lagged urbanization rate, lagged hydro inflows, lagged change in the demand, two period lagged change in the demand, lagged change in GDP, lagged change in urbanization rate, changes in hydro inflows, lagged change in hydro inflows and connections. In the long run the drivers were GDP, hydro inflows and urbanization rate. In the commercial and industrial sector, the main drivers of electricity demand in the short run were lagged electricity demand, lagged energy efficiency, lagged output, hydro inflows, lagged price of electricity, lagged change in the demand, lagged change in efficiency, two period lagged change in the efficiency, lagged change in output, two period lagged change in output and reforms. In the long run the drivers were efficiency, output, hydro inflows and price of electricity.

Electricity demand was found to be a normal good. Its demand increased with income and decreased with price. Aggregate electricity demand was found to be income inelastic. Household electricity demand was found to be income elastic. Commercial and industrial electricity demand was found to be income elastic but price inelastic. Supply side challenges of hydro inflows were found to have the potential to constrain electricity demand creating suppressed or unmet demand in the subsector.

Energy demand was projected to rise at an average growth rate of 5.7%. This was close to the historical average growth rate of 5%. The projection was lower than the official forecast in Lahmeyer international GmbH (2016) that forecasted an average growth rate of 7.3% and Republic of Kenya (2013b) whose projected growth rate averaged 13.5%. The official forecast was found to be overstated. Commercial and industrial electricity demand was projected to increase by 4% while the household electricity demand was project to increase by 6%. Commercial and industrial electricity demand was projected to continue being the highest contributor to electricity demand.

2.4 Policy recommendations

The finding that hydro inflows influence electricity demand in Kenya indicated the need for the government to address supply side issues and constraints. Measures aimed at diversifying sources of electrical energy should be intensified to avoid dependency on hydro generated energy that has resulted in load shedding programs in the past during drought. The Government should ensure procurement of power plants is diversified based on the existing natural resources. The planned generation projects seem diversified as they include geothermal, coal, natural gas, solar, wind and biomass (Republic of Kenya, 2013b). The customer connections and grid strengthening measure should also continue as they reduce suppressed and unmet demand occasioned by power blackouts and lack of power supply.

There is need to supplement the demand forecast model being used in the sector with the one proposed in this study. This will facilitate a comparison of the results from the end user excel based model and with one based on the economic study. This study model used available aggregated base data which may be more reliable. The base data in the end user model is less reliable and based on deduced assumptions (Lahmeyer International GmbH, 2016). Further the end-user model does not include the effects of price and inter-fuel substitution on electricity demand. There is need to review investment plans made in the 5000MW+ investments prospectus using the forecast under Republic of Kenya (2013b) to avoid overinvestment in the electricity subsector. Overinvestment is likely to cause an increase in electricity prices. This is because consumers will be required to pay for the non-utilized contracted capacity (Republic of Kenya, 2018b). Alternatively, KPLC should engage generators on take and pay contracts instead of take or pay to avoid payment of excess generation capacity hence increasing electricity tariff.

Commercial and industrial consumer will continue being the leading contributors to electricity demand followed by household consumers. Since price of electricity was found to be a significant consideration for commercial and industrial consumers, the government and the energy regulatory commission should reduce electricity prices for commercial and industrial consumers. Other measures that can achieve the reduced tariffs include time of use tariff and a tax rebate program. Such innovative policy measures should continue being implemented to encourage growth in demand for electricity.

2.5 Contribution of the study

Previous studies on electricity demand have not considered the role of supply side constraints in driving electricity demand. This study examined the role of supply constraints in electricity demand by focusing on hydro inflows. The study found hydro inflows affected aggregate, household, commercial and industrial electricity demand. Eliminating the supply side constraints would positively influence electricity demand.

The study contributes to policy by comparing the official demand forecast that uses engineering method with a forecast based on economic approach. The findings indicate the need to supplement the end user approach used in the official forecast with the methodology proposed in this study. The study also finds the official demand forecast could be overstated indicating the need to revisit the investment plans to avoid increased electricity costs associated with demand and supply imbalance.

2.6 Limitations of the study

The study analysed demand using aggregate time series data aggregated for the entire country. This is due to scarcity of data that would allow an analysis of demand up to the county level. A forecast at the county level is also important for devolved government energy planning purposes.

The study used hydro inflows to represent supply side constraints. Other supply side constraints such as average interruptions of power supply to customers and the duration of these interruptions that contribute to the unmet demand were ignored due to the lack of such data.

2.7 Areas for further research

The study did not consider hourly demand variations or regional demand. As the country develops towards an open market access system and implement county energy plans, such analysis will become important. Statistics should also be captured to this level to facilitate such analysis.

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CHAPTER 3

TECHNICAL EFFICIENCY OF THERMAL ELECTRICITY GENERATORS IN KENYA

Abstract

The Government of Kenya introduced energy sector reforms in the 1990s aimed at improving efficiency in the supply of energy. After over two decades of reforms, there has been no comprehensive study to estimate the technical efficiency amongst electricity generators in Kenya. This study examined 27 thermal electricity generating plants in Kenya using data sourced from Energy Regulation Commission for the period July 2015 to December 2017. That was the only period that the data was available. The study applied two methods to estimate firm efficiency, viz., the Stochastic Frontier Analysis and Data Envelope Analysis. The results indicated that there is inefficiency in thermal power generation. The average efficiency score was 71% meaning the industry was missing its technical potential by about 29%. Grid connected power plants were found to be more efficient compared to isolated plants. The plants experienced increasing returns to scale and were improving on efficiency and productivity. The main factors that determined efficiency were age of the plant, grid connection and plant ownership. While age and public ownership contributed to inefficiency, grid connection had a positive effect on the efficiency. The government should continue encouraging private investment in power generation while at the same time increasing connection of the isolated areas to the national grid. The regulator should also revisit the current specific fuel targets used in determining the fuel pass through costs to consumers to encourage efficiency.

3.0 Introduction

The energy sector is important in the development of an economy. Kenya's blue print for development, the Vision 2030 envisaged social transformation founded on the energy sector amongst other infrastructure services (Republic of Kenya, 2007). The first Medium Term Plan 2008-2012 (Republic of Kenya, 2008), and the second Medium Term Plan 2013-2017 (Republic of Kenya, 2013) recognize the need for efficient, accessible and reliable infrastructure. Therefore, energy producers should be efficient.

The electricity industry in Kenya comprises of generation, transmission and distribution segments. Generation is the production of electricity from hydro, geothermal and fossil fuels such as diesel and gas. Electricity is also produced from wind and solar at a lower level. Transmission is the transportation of electrical energy from the generating plants through high-voltage power lines and over long distances to the distributing company. At the distribution company high-voltage power is scaled down to lower voltages and distributed to industrial and household consumers. KPLC undertakes distribution and retail functions in the electricity subsector (Republic of Kenya, 2018a).

From the 1990s, the government embarked on power sector reforms. The objectives of the reforms were to commercialize energy services, increase operational efficiency and allow private investment in energy (Republic of Kenya, 2004). The Electric Power Act of 1997 unbundled generation from transmission and distribution. It also allowed private sector investment in power generation thereby allowing independent power producers. The Act also established an independent regulator, the Electricity Regulatory Board (ERB) which later became the Energy Regulatory Commission (ERC) through the Energy Act of 2006 (Republic of Kenya, 2006).

Initially the reforms concentrated on liberalizing generation. Kenya Electricity Generating Company (KenGen) the national electricity generator, would from henceforth compete with independent power producers. Subsequent reforms as provided for in the Sessional Paper No 4 of 2004 on energy unbundled Kenya Power and Lighting Company (KPLC) into two entities, KPLC and the Kenya Electricity Transmission

Company (KETRACO). KETRACO was formed in 2008 with the sole mandate of building high voltage transmission lines. These reforms were expected to encourage competition at the distribution, wholesale and retail levels. This was with the aim of lowering electricity tariffs (Republic of Kenya, 2004).

So far, electricity generation in Kenya is open to competition. Competition mainly happens during the procurement of power plants. Transparent procurement of the generation has encouraged private participation and competitive prices (Godinho and Eberhard, 2019). However, this competition is limited as all generators have long term take or pay power purchase agreements (PPA) with KPLC. The PPA locks the generation tariff for the entire period of the contract (Electricity Regulatory Board, 2005). Competition has also been further eroded by generation projects that have been procured through direct negotiations and feed in tariffs programme. This has been attributed to political influence (Godinho and Eberhard, 2019). Plans are underway to introduce energy auction to replace the feed in tariffs programme and open the distribution segment to by allowing more private players (Republic of Kenya, 2018b).

The first independent power producers (IPPs) in Kenya were mainly thermal plants. By the year 2000 there were four IPPs, three using fossil fuel and one using geothermal to generate electricity. The number of IPPs has since increased to fifteen of which 6 are thermals plants with an installed capacity of 709MW. As indicated in Table 3.1, thermal power plants contribute to 76% of the installed capacity from the private sector. The public sector dominates the generation sector contributing 70% of the installed capacity. This is through the state-owned generator KenGen which mainly uses hydro technology and the government has invested heavily in this area.

Table 3.1: Kenya’s Electricity Generation Installed capacity

Type	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**Average (5 years)**
Hydro	817	820	820	818	818	818.6
Geothermal	253	488	493	513	513	452
Thermal	255.4	253.9	253.9	254	254	254.24
Wind	5.3	25.5	25.5	25.5	25.5	21.46
KenGen	*1330.7*	*1587.4*	*1592.4*	*1610.5*	*1610.5*	*1546.3*
Thermal	26.6	28.1	27.1	26.2	30.4	27.68
Solar	0.7	0.569	0.569	0.55	0.69	0.62
Wind	0.6	0.55	0.55	0.66	0.55	0.58
Isolated power plants	*27.9*	*29.219*	*28.219*	*27.41*	*31.64*	*28.88*
Total Public sector	**1358.6**	**1616.6**	**1620.6**	**1637.9**	**1642.1**	**1575.2**
Geothermal	110	110	139	139	150	129.6
Thermal	389.5	546.82	552.82	522.82	522.82	506.96
Small hydros	0.81	0.81	0.81	5.81	8.31	3.31
Biomass/Cogeneration	26	26	28	28	28	27.2
Solar	0	0	0	0	0.25	0.05
Total Private sector	**526**	**684**	**721**	**696**	**709**	**667.1**
Total	**1885**	**2300.3**	**2341.3**	**2333.5**	**2351.5**	**2242.3**
% share of Private sector (IPPs)	**28%**	**30%**	**31%**	**30%**	**30%**	**30%**
% share of Thermal (IPPs)	**74%**	**80%**	**77%**	**75%**	**74%**	**76%**

Source: KPLC, various annual reports

The Government has been very sensitive to increasing tariffs and has initiated the review of all thermal PPAs. This is informed by the perception that the cost of energy from privately owned thermal power plants was high (Godinho and Eberhard, 2019). This necessitates a study on the efficiency in the production of energy and compare the performance of public and private owned thermal generators. The long-term plan indicates the need for 1,890 MW of gasoil fuelled plants by the year 2035 to provide balancing reserves to the system (Lahmeyer International GmbH, 2016). There is therefore need to understand the drivers of the efficiency to inform the implementation of the planned projects.

Though the electricity industry has several players at the generation stage their efficiency of production is unknown. There is need to understand the efficiency of state and privately owned plants as well as grid and isolated generators. In order to examine efficiency in similar technologies the study focused on thermal power plants.

3.0.1 Statement of the research problem

The electricity sector has been struggling with high tariffs that the government has attributed to low investments and operational inefficiencies (Republic of Kenya, 2004). This is despite the reforms that begun in the 1990s aimed at addressing shortfalls in power supply by broadening generation and increasing efficiency in the supply of power (Republic of Kenya, 1997, 2004). Consequently, electricity generation was opened to private sector participation. The government has continued with reforms aimed at improving efficiency in electricity supply and ensuring competitive power supply (Republic of Kenya, 2018b). The reform agenda has been pursued without any study on the productive efficiency levels of firms involved in the supply of electricity. Before this study, there was no comprehensive study on the efficiency levels of electricity generating power plants in Kenya even though its known that efficiency brings competitive pricing. This study tried to fill this gap by evaluating the efficiency of electricity generators in Kenya and examining the determinants of efficiency. Government has expressed concerns with the performance of privately owned thermal power plants (Godinho and Eberhard, 2019). This necessitates a study on the performance of privately owned thermal power plants compared to public owned plants.

3.0.2 **Research questions**

The study attempted to answer the following general question: Are thermal power plants in Kenya efficient? The specific questions were:

1. What is the technical efficiency level of thermal power plants in Kenya?
2. What drives efficiency in the power sector in Kenya?
3. How has the level of efficiency changed from July 2015 to December 2017?

3.0.3 **Objectives of the study**

The overall objective of this study was to establish the efficiency of thermal electricity generating plants in Kenya. The specific objectives were:

- To estimate the technical efficiency of thermal power generating plants.
- To examine the drivers of technical efficiency in the power sector in Kenya.
- To assess the efficiency changes from July 2015 to December 2017.

3.0.4 **Significance of the study**

The provided evidence on operational efficiency of electricity generating plants in Kenya is critical for future policy interventions and reforms. The research findings on the determinants of efficiency informs ERC's future regulatory decisions and in the design of regulatory incentives. The information also benefits the Ministry of Energy in deciding whether future power projects should be implemented by KenGen a public owned company or private owned companies. The findings also inform the Ministry on whether grid or isolated projects are more efficient.

3.1 **Literature review**

3.1.1 **Theoretical literature**

Technical efficiency is a concept from production theory. Production involves the conversion of inputs into outputs. The production function describes the firms' technology and gives the maximum output that can be produced from a given set of inputs (Battese, 1992). The state of technology determines and restricts input and output combinations that are technologically feasible (Jehle and Reny, 2011). The production technology is described in either a behavioural objective function, for example a cost minimization or profit maximisation or in a distance function that is described using a multi-input and multi-output production technology (Coelli, Rao, O'Donnell and Battesse, 2005). The duality of a production function is the cost function (Jehle and Reny, 2011). A production function is suitable in empirical work when output is endogenous (Christensen and Greene,1976) and input prices are unknown (Coelli et al., 2005).

Productivity and efficiency measures assess the performance of decision making units. Jehle and Reny (2011) details elementary measures used to measure efficiency, this includes marginal product and average product. Marginal product is the partial derivative of output with respect to one of the inputs, it gives the rate at which output changes per additional unit of that input. Average product is the total output produced per unit of an input. The most popular but least satisfactory measure in this regard is average productivity of labour. The dissatisfaction arises from consideration of labour as a sole input in production. Efficiency measures consider all factors rather than a single of production (Farell,1957).

Farell (1957) defines efficiency of a firm to be the achievement associated with producing as much output as possible from a given set of inputs. It takes the values of unity (100%) for a perfectly efficient firm and becomes very small for an inefficient firm. Efficiency is a comparative concept that benchmarks one decision making unit performance against another or others. The production frontier indicates the maximum attainable output from each input level. Any firm operating on the production frontier is technically efficient. Any firm operating below the frontier is technically inefficient. According to Coelli et al., (2005), productivity of a firm can also be measured through

Total Factor Productivity (TFP). Comin (2010) defines TFP as the portion of output not explained by the amount of inputs used in production.

According to Fried, Lovell and Schmidt (2008) efficiency has technical and allocative components. Technical efficiency is the capability to produce as much output as the technology and inputs allow. Put differently, it is also reducing inputs to the minimum in producing a desired output subject to a given technology. Allocative efficiency considers the cost of production. Allocative efficiency involves choosing inputs that produce a given output at lowest cost given the prevailing input prices (Fried et al., 2008). Combining allocative and technical efficiency gives the overall economic efficiency (Coelli et al., (2005). Technical inefficiency is the amount of inputs that can be proportionately reduced without a reduction in output (Coelli et al., 2005). Daraio and Simar (2007) describe efficiency as the distance between the quantity of input and output. They consider efficiency to be more accurate than productivity as it's a comparison with the most efficient frontier.

Power generation involves transforming several inputs to power (Chien, Chen, Lo and Lin, 2007). Electricity generation plants produce a homogenous output that is electrical energy, but their inputs differ based on the technology applied (Jamasb, 2007). This means productivity and efficiency measures can be used to assess their performance.

3.1.2 **Measures of efficiency**

Parametric and non-parametric techniques are used to estimate firm level efficiency. DEA is non-parametric and involves mathematical programming. SFA is parametric and involves econometric methods. The difference between the two methods is that DEA does not set an a priori production function or assumptions on the distribution of the error term. It is a linear programming technique. On the other hand, parametric SFA makes a priori functional form and can either be deterministic or stochastic depending on the random noise (Ngui, 2008).

The stochastic model distinguishes the noise effects from the inefficiency effects and allows for economic interpretation of parameters. However, a bad functional specification can be confused for inefficiency (Gonzalez and Trujillo, 2007). DEA is advantageous in that it easily handles many inputs and outputs (Daraio and Simar, 2007). Variable returns to scale and constant returns to scale models are used in evaluating the performance of the firm (Ngui, 2008). It also does not need a pre-specified optimizing behaviour by the economic unit such as costs minimization and profit maximization and neither does it require price or cost data (Arocena and Waddams, 2002). However, its disadvantage is that it does not allow for hypothesis testing and the estimated efficiency can be affected by the presence of a random noise. None of the two approaches is superior (Gonzalez and Trujillo, 2007) and some studies such as Saleem (2007) and Domah (2002) have used both methods and compared their results.

DEA approach

A DEA model is either input or output oriented. Input oriented framework is used when the output level remains unaffected when input quantities are minimized until the frontier is reached. Output oriented method maximizes output levels by holding the input bundle unchanged.

According to Coelli et al., (2005), a constant returns to scale (CRS) model for n firms with i inputs and q outputs with iXn input matrix X and $qX\ i$ output matrix Y can be derived by getting the ratios of outputs and inputs, $u'y_n/v'\,x_n$ where $u\ is\ qX1$ vector of output weights and $v\ is\ iX1$ vector of input weights. The optimization problem takes the form;

$$max_{u,v}\, u'y_n/v'\,x_n$$

$$\text{Subject to } u'y_j/v'\,x_j \leq 1, j = 1,2 \ldots \ldots N$$

$$u, v \geq 0 \qquad 3.1$$

These equation solutions are infinite. If u^*, v^* are solution, then $\alpha u^*, \alpha v^*$ are another solution etc. The problem is avoided by imposing the constraint $v'x_n = 1$ such that;

$$max_{u,v}\, u'y_n$$
$$\text{Subject to } v'x_n = 1$$
$$u'q_j - v^1 x_j \leq 0, j = 1,2 \dots \dots$$
$$u, v \geq 0 \qquad 3.2$$

Duality allows the problem in 3.2 to be derived as;

$$\min_{\theta,\lambda} \theta$$
$$\text{Subject to } -y_n + Y\lambda \geq 0$$
$$\theta x_n - X\lambda \geq 0$$
$$\lambda \geq 0 \qquad 3.3$$

θ is a scalar and λ is a $nX1$ vector of constants. θ is the efficiency score of the n^{th}firm and satisfies $\theta \leq 1$. A value of 1 indicates a technically efficient firm. θ is obtained for each of the firm in the sample.

Coelli et al. (2005) indicate that using a CRS specification for firms which are not functioning at optimal scale affects the efficiency measure. This can be corrected by allowing Variable Return to Scale (VRS). This can be done by including $n1'\lambda = 1$ to equation 3.3 to provide;

$$\min_{\theta,\lambda} \theta$$
$$\text{Subject to } -y_n + Y\lambda \geq 0$$
$$\theta x_n - X\lambda \geq 0$$

$$n1'\lambda = 1$$
$$\lambda \geq 0 \qquad 3.4$$

where $n1$ is an $nX1$ vector of ones. This constraint allows for benchmarking of firms of similar size. This is not the case with a CRS DEA. Coelli et al. (2005) specifies the relationship between CRS, VRS and scale efficiency to be

$$TE_{CRS} = TE_{VRS} \times SE \qquad 3.5$$

where TE_{CRS} is the CRS efficiency, TE_{VRS} is the variable efficiency and SE is the scale efficiency.

To establish the nature of the returns to scale, the convexity constraint $n1'\lambda = 1$ is amended to $n1'\lambda \leq 1$ to have

$$\min_{\theta,\lambda} \theta$$

$$\text{Subject to} \qquad -q_n + Q\lambda \geq 0$$
$$\theta x_n - X\lambda \geq 0$$
$$n1'\lambda \leq 1$$
$$\lambda \geq 0 \qquad 3.6$$

The firm's scale inefficiencies can be determined by estimating equations 3.4 and 3.6. If the firm efficiency results are unequal, then we have increasing returns to scale.

Similar to the input-oriented DEA in equation 3.6, an output-oriented DEA can be specified as (Coelli et al., 2005)

$$\max_{\theta,\lambda} \theta$$

$$\text{Subject to} \quad -\theta y_n + Y\lambda \geq 0$$

$$x_n - X\lambda \geq 0$$

$$n1'\lambda = 1$$

$$\lambda \geq 0 \qquad 3.7$$

With panel data, Malmquist TFP index is used to measure change in productivity. Productivity change is decomposed into technical change and efficiency change (Coelli 1996a). Coelli (1996a) and Coelli et al. (2005) specified an output based Malmquist productivity change index of production point (X_{t+1}, q_{t+1}) relative to production point (X_t, q_t) as:

$$m_0(q_{t+1}, X_{t+1}, q_t, X_t) = [m_0^{t+1}(q_{t+1}, X_{t+1}, q_t, X_t) \times m_0^t\,(q_{t+1}, X_{t+1}, q_t, X_t)]^{\frac{1}{2}} = \left[\frac{d_0^t\,(X_{t+1}, q_{t+1})}{d_0^t(X_t, q_t)} \times \frac{d_0^{t+1}(X_{t+1}, q_{t+1})}{d_0^{t+1}(X_t, q_t)}\right]^{1/2} \qquad 3.8$$

A value greater than one indicate TFP growth from period t to period $t+1$. Where technical inefficiency is present, that is $d_0^{t+1}(X_{t+1}, q_{t+1}) \leq 1$ and $d_0^t(X_t, q_t) \leq 1$. Equation 3.8 can be rewritten as

$$m_0(q_{t+1}, X_{t+1}, q_t, X_t) = \frac{d_0^{t+1}(X_{t+1}, q_{t+1})}{d_0^t(X_t, q_t)}\left[\frac{d_0^t\,(X_{t+1}, q_{t+1})}{d_0^t(X_t, q_t)} \times \frac{d_0^{t+1}(X_{t+1}, q_{t+1})}{d_0^{t+1}(X_t, q_t)}\right]^{1/2} \qquad 3.9$$

The ratio outside the brackets on the right hand side measures the technical efficiency change between periods $t+1$ and t. The ratio inside the bracket provides the technology change. Solving this equation involves solving the following linear programming problems (Coelli, 1996a);

$$[d_0^t(X_t, q_t)]^{-1} = max_{\theta,\lambda}\, \theta$$

Subject to $-\theta q_{nt} + Q_t\lambda \geq 0$

$$x_{nt} - X_t\lambda \geq 0$$

$$\lambda \geq 0 \qquad 3.10$$

$$[d_0^{t+1}(X_{t+1}, q_{t+1})]^{-1} = max_{\theta,\lambda}\, \theta$$

$$\text{Subject to } -\theta q_{nt+1} + Q_{t+1}\lambda \ \geq 0$$

$$x_{nt+1} - X_{t+1}\lambda \geq 0$$

$$\lambda \geq 0 \qquad 3.11$$

$$[d_0^{t}\,(X_{t+1}, q_{t+1})]^{-1} = max_{\theta,\lambda}\, \theta$$

$$\text{Subject to } -\theta q_{nt+1} + Q_{t}\lambda \ \geq 0$$

$$x_{nt+1} - X_{t}\lambda \geq 0$$

$$\lambda \geq 0 \qquad 3.12$$

$$[d_0^{t+1}(X_{t}, q_{t})]^{-1} = max_{\theta,\lambda}\, \theta$$

$$\text{Subject to } -\theta q_{nt} + Q_{t+1}\lambda \ \geq 0$$

$$x_{nt} - X_{t+1}\lambda \geq 0$$

$$\lambda \geq 0 \qquad 3.13$$

Scale efficiency can also be considered by additional convexity constraint $N1'\lambda = 1$ as in equation 3.4.

Stochastic Frontier Analysis

The stochastic production frontier measures production efficiency and is considered to have an advantage over DEA owing to its ability to consider measurement error and noise in the data in the estimation. Aigner, Lovell and Schmidt (1977), Coelli (1996b), Saleem (2007) and Ngui (2008) specify a stochastic production frontier as;

$$q_i = f(X_i, \beta) + \ \varepsilon, \text{and } \ \varepsilon = v_i - \mu_i \qquad 3.14$$

where $i = 1 \ldots . N$ is the number of decision making units. q_i is output of i, $f(.)$ is the production technology, X_i is a vector of inputs in each plant i, β is a vector of parameters to be estimated. ε is the error term of which, μ_i is the technical inefficiency of production and v_i is a systematic disturbance term assumed to be independently and identically distributed as $N(0, \sigma_v^2)$. If $\sigma_v^2 = 0$, the model collapses to a deterministic frontier and all deviations from the frontier are assumed to be due to technical inefficiency (Aigner et al., 1977, Battese and Coelli, 1992). μ_i is assumed to be distributed independently of v_i and to satisfy $\mu_i \leq 0$, μ_i is derived from a $N(0, \sigma_u^2)$ distribution truncated above at zero. It collapses to a stochastic production frontier model when $\sigma_u^2 = 0$ (Aigner et al., 1977). μ_i represent technical inefficiency of production (Ngui, 2008). The non-positive disturbance term μ_i indicates that a firm's output must either be below or on the stochastic production frontier (Aigner et al., 1977) and the stochastic frontier $(x_i\, \beta + v_i)$ can vary across firms or overtime for the same firm (Ngui, 2008, Aigner et al., 1977).

A linear transformation of equation 3.14, takes the form

$$lnq_i = \beta_0 + \beta_1 lnx_i + v_i - u_i \qquad 3.15$$

lnq_i is the logarithm of the output of the i^{th} plant, x_i is a $K\ X$ 1 vector of inputs, β is a vector of unknown parameters, v_i is the random error term.

Taking the antilog of equation 3.15 gives,

$$q_i = \exp(\beta_0 + \beta_1 x_i + v_i - u_i) \qquad 3.16$$

Equation 3.16 can be rewritten as

$$q_i = \underbrace{\exp\,(\beta_0 + \beta_1 x_i)}_{deterministic\ component} \times \underbrace{\exp(v_i)}_{noise} \times \underbrace{\exp(-u_i)}_{inefficiency} \qquad 3.17$$

The technical efficiency is the ratio of the observed output to the potential output and is represented in Coelli et al. (2005) and Ngui (2008) as follows.

$$TE_i = \frac{q_i}{\exp(x_i\beta + v_i)} = \frac{\exp(x_i\beta + v_i - u_i)}{\exp(x_i\beta + v_i)} = \exp(u_i) \qquad 3.18$$

The noise component v_i has a zero mean, is uncorrelated with the explanatory variables x_i and is homoscedastic. The inefficiency component has a non-zero mean (Coelli et al., 2005).

Belotti, Daidone, Ilardi and Atella (2013) and Battese and Coelli (1995) indicate the need to include determinants of inefficiency in the SFA estimation as opposed to a two-stage estimation. In a two-stage regression the estimated efficiencies are regressed on firm specific variables. The two-stage regression is considered likely to give estimates that are less efficient as it contradicts the assumption of identically distributed inefficiency effects (Battese and Coelli, 1995).

Battese and Coelli (1995) proposed a model for unbalanced panel data that is expressed as

$$q_{it} = \beta x_{it} + (v_{it} - u_{it}) \qquad i = 1, \ldots, N,\ t = 1, \ldots, T \qquad 3.19$$

where q_{it} is the log of the output of the i^{th} firm in the t^{th}period, x_{it} is a k×1 vector of the log of the input quantities of the i^{th} in the t^{th} period, β is a vector of parameters to be estimated, v_{it} are random variables assumed to be independently and identically distributed $N(0, \sigma_v^2)$ and independent of the u_{it}

$$u_{it} = \mathrm{U_i}\exp[-\eta(\mathrm{t} - \mathrm{T})]$$

u_{it} are random variables accounting for technical inefficiency and are assumed to be independently and identically distributed, non-negative truncations of the $N(\mathrm{u}, \sigma_{\mathrm{u}}^2)$ distribution;

η is a parameter to be estimated

Technical efficiency is given by

$$TE = \frac{q_{it}}{q*} = \frac{q_{it}}{\exp(x'_{it}\beta + v_{it})} = \frac{\exp(x'_{it}\beta + v_{it} - u_{it})}{\exp(x'_{it}\beta + v_{it})} = \exp(u_{it}) \quad 3.20$$

Battese and Coelli (1995) specification improved this specification by including the specific variable hypothesised to affect efficiency. The only difference being that u_{it} are assumed to be independently distributed such that the distribution of u_{it} is truncated at zero of the normal distribution with a mean of ∂z_{it} and a variance of σ_u^2. The technical inefficiency effect u_{it} is given as

$$u_{it} = \partial z_{it} + w_{it} \quad 3.21$$

where z_{it} is a vector of variables that may influence the efficiency of the firm, ∂ are the parameters to be estimated and w_{it} is a random variable with a zero mean and variance σ_w^2.

3.1.3 **Empirical literature**

Measures of efficiency

Several studies dating back to the 1990s have measured the productive efficiency of electricity generating companies. Most of these studies use Data Envelope Analysis (DEA) and Stochastic Frontier Analysis (SFA). Golany, Roll and Rybak (1994) analyses the efficiency of 87 plants owned by Israeli electric company and finds only 39 plants were efficient. The study uses DEA and several inputs and outputs. The outputs include generated power, operational availability, pollutant emissions, deviation from load and operation parameters. The inputs include installed capacity, fuel consumption, internal power consumed by the plant, capital, manpower, fuel stock and all non-labour expenses.

Some studies have analysed efficiency for thermal industries using regions as the decision making unit. Lam and Shiu (2001) study for China's thermal power generation industry using 30 provinces as the decision making units finds the average efficiency to be 88.8% in 1995 and 90.3% in 1996. Electricity generated by power plants in each decision making unit (DMU) is used as the output variable, while capital, fuel and labour are the inputs. Fatima and Barik (2012) also uses regions as the DMU in a study of efficiency of thermal plants in India. The study uses energy generated as output. The inputs considered include capital, labour, auxiliary energy consumed and materials. Data for 14 states for the period 2001 to 2008 is used for the SFA analysis. The study finds efficiency to average 80.35%.

Chang and Toh (2007) examines the efficiency of three electricity generation companies in Singapore using DEA and SFA for the years 1999-2004. The study finds the average efficiency using SFA to be 90.35% and using DEA to be 98.33%. The study uses electricity generated as output and capital depreciation, staff wages and fuel expenditure as the inputs. Shanmugam and Kulshreshtha (2005) study for India's 56 coal thermal based power plants finds the efficiency level to be on average 72.7%. The study also finds coal and capital to be the significant determinants of coal based generation. The study uses panel data from 1994- 2002. Power generation is used as the output. Inputs include capital (installed capacity), coal, secondary oil and auxiliary power consumption.

In a recent study for India, Vijai (2018) analyses the technical efficiency of 30 coal power plants for the period 2007-2008. The study finds the mean technical efficiency to be 88.2%. Unlike the earlier study by Shanmugam and Kulshreshtha (2005), this study uses only two inputs coal and capacity while the output is the energy generated by the power plants. Both studies indicate inefficiency in India's coal power plants. However, there is some improved performance as indicted in the efficiency score of the latter study by Vijai (2018).

Some of the literature reviewed has focused on a comparative analysis of efficiency of electricity generation plants based on their ownership. One such study is that of Saleem (2007) who estimates impact of ownership of efficiency of power plants. Using DEA and the SFA, the study estimates efficiency of 21 electricity generating plants in Pakistan, 12 private and 9 public. The analysis examines units generated (output) and inputs used (fuel and capital) in a panel data of 6 years 1998-2003. The results show technical inefficiencies with a mean efficiency of 78% and the need to improve the performance in the sector. The study finds capital to be significant in the generation of electricity and that there increasing returns of 3.21. The Malmquist DEA analysis shows that only two private and one public firm could gain managerial efficiency. The study findings are consistent with a more recent study by Khan (2014) in Pakistan. Using data for 31 generating power plants in Pakistan over the period 2006-2011, the study finds private independent power plants to be more efficient than public owned power plants. The study attributed this to lack of operational maintenance and routine repairs by the public power plants.

Another study that estimates ownership effects on efficiency is Arocena and Waddams (2002). The study explores the differences in performance between public and private coal fired generators in Spain using the Malmquist productivity index. The inputs considered are capital (MW of installed capacity), labour (average number of employees) and fuel (millions of therms). The outputs are the annual net power produced by each generating unit, declared available capacity, and three pollutants namely sulphur dioxide, nitrogen dioxide and particulates. The results indicate public owned generators to be more efficient than privately owned generators.

Efficiency analysis has also been used to analyse power generating plants in island and non-island locations. Domah (2002) compares technical efficiency of fossil-fired generators in 16 small island economies and 121 investor owned generators in the US. The study uses panel data to undertake DEA and SFA. Electricity generated is the output. Labour employed, capital and fuel consumption are the inputs. The results from DEA and SFA are comparable and indicate that there is no difference between islands and non-islands generators. Again, neither is less technically efficient. The results also indicate the possibility of benchmarking islands with non-island generators.

Comparative analysis of generating plants between countries has also been studied. In a study of the efficiency of Asian energy firms using DEA approach, Riaz, Khan, Qayyum and Khan (2013) considers two outputs, energy revenue and other revenues, and three inputs, fuel cost, salary expense and user costs of capital. The results indicate the overall technical efficiency to be 0.59 on average, meaning that the companies could attain same revenues by reducing inputs by 41%. Companies from Philippines are more technically efficient on average. Using Tobit analysis, the study also examines the determinants of technical efficiency. The results find size, liquidity and leveraging firms to be the main determinants. Larger firms and those with more liquid assets are found to be more technically efficient. Companies that are more leveraged are less technically efficient.

Another area that has been studied is the impact of reforms on efficiency of plants. Malik, Cropper, Limonov and Singh (2011) studies the impact of unbundling on efficiency of state thermal power plants in India. Using unbalanced panel of 385 coal electricity generating units for the years 1988-2009, the study finds that unbundling has not improved thermal efficiency. It has however improved plant availability and reduced outages. The thermal efficiency studied is the plant heat rate. Although the study assesses the performance of the power plants, the focus was mainly on technical plant parameters as opposed to the performance of the plants as decision making units.

Iimi (2003) used productivity analysis to estimate the scales economies of power generation, transmission and distribution in Vietnam using SFA. Generated electric energy is the output while capital, labour and fuel are inputs. Capital is the installed capacity; labour is plant specific expenditure and fuel is in terrajoule (TJ). The author finds increasing returns to scale in power generation. Transmission and distribution have insignificant but positive returns to scale. The study concludes that vertical integration where all the stages are owned by one entity is better than unbundling.

Determinants of efficiency

Several studies have estimated the determinants of efficiency. Saleem (2007) analyses the effects of ownership on efficiency in Pakistan. The study undertakes a Tobit analysis with size and public ownership as the determinants of efficiency. Public ownership is found to have a significant negative impact on the technical efficiency of the firms while size has a significant positive effect.

Lam and Shiu (2001) estimates the determinants of technical efficiency change for thermal power plants in China. The study finds fuel efficiency and capacity factor to significantly affect efficiency change. Fuel efficiency has a negative effect while capacity factor effect is positive. The finding on capacity factor is similar to that of Domah (2002) in the study for islands and non-islands utilities in the USA.

In a study for India, Fatima and Barik (2012) finds technical efficiency to be positively determined by high technical manpower and richness of the state measured by state domestic product, and negatively by unbundling reforms. They attribute the negative coefficient for reforms to the incomplete implementation of the reforms and resistance from authorities. The study uses the Battese and Coelli (1995) model.

In Mexico, Marmolejo and Rodríguez (2015) attributes the inefficiency of 81% of the thermoelectric units to ageing of power plants. The age increased the wear and tear of the projects increasing the required budget for maintenance which may not always have been available due to limited resources.

3.1.4 **Overview of literature and research gap**

In the analysis of efficiency, the main inputs of consideration are capital, fuel and labour while the output is annual net power produced. Studies that apply both DEA and SFA consider only one output mainly due to the challenge in estimating more than one output when using SFA. DEA Malmquist productivity index is used to estimate functions with more than one output and use panel data (Golany et al., 1994, Arocena and Waddams, 2002, and Chien et al., 2007). Some studies use both methods and compare the results (e.g Saleem, 2007 and Domah, 2002). Malmquist productivity index is also able to show the changes in efficiency. The independent variables are the inputs transformed to power by the generators (Chien et al., 2007). Most of the studies reviewed (Lam and Shiu, 2001; Arocena and Waddams 2002; Saleem, 2007; Riaz et al., 2013) used capacity of the generators, fuel and labour as inputs.

The determinants of technical inefficiency are estimated using either one step or two step analysis. The two step analysis employs a Tobit model on estimated efficiency coefficients against the determinants of interest such as per capita electricity consumption, maximum demand, plant/capacity factor, load factor, number of customers and dummy variables for ownership, reforms, island and interconnectivity (Riaz et al., 2013, Fatima and Barik 2012, Saleem 2007, Domah 2002, Lam and Shiu, 2001). Marmolejo and Rodríguez (2015) also suggests the need to consider the effects of age of the plant on efficiency. Belotti et al. (2013) and Battese and Coelli (1995) suggest one step estimation of determinants of technical efficiency to be superior to two step analysis. This is because it avoids contradicting the assumption of identically distributed inefficiency effects that is likely to result in less efficient estimates. This study therefore adopts the one step analysis and considers age, ownership and isolated grid as the determinants of technical efficiency.

The literature reviewed is mainly from US, Europe and Asia and there is paucity of research in this area for the Africa region. There is a research gap on the level of efficiency amongst electricity generators in Kenya too. This study will add to literature by estimating the efficiency of electricity generators in Kenya. Efficiency changes for the period of study will also be estimated using Malmquist productivity index.

3.2 Methodology

3.2.1 Theoretical framework

The production possibility of a firm is represented using a production function (Coelli et al., 2005). The production function describes the amount of output that can be produced from a vector of inputs (Jehle and Reny, 2011). The production function is summarised as (Coelli et al., 2005; Jehle and Reny, 2011)

$$y = f(X) \qquad 3.22$$

where y is the output and $X = (x_1, x_2, \dots, x_N)$ is an $N\ X\ 1$ vector of inputs. The inputs and output are non- negative, $y \geq 0$ and $X \geq 0$. Equation 3.22 can be written as (Coelli et al., 2005);

$$y = f(x_1, x_2, \dots, x_N) \qquad 3.23$$

where y is the output and dependent variable and $x_1, x_2, \dots, x_N$ are the inputs and independent variables. $f(.)$ is an algebraic function.

A firm that is technically efficient produces output y equal to the production frontier $f(X)$. Assuming a linear model and correcting for deviations from the frontier due to inefficiency, omission and misspecification errors, equation 3.23 becomes the stochastic production frontier model (Coelli et al., 2005);

$$lny_i = X_i'\beta + v_i - \mu_i \qquad i = 1 \dots I \qquad 3.24$$

where y_i is the output of ith firm, X_i is a $K\ X\ 1$ vector of input variables, β is a $K\ X\ 1$ vector of unknown parameters, v_i is a random error representing statistical noise, μ_i is the technical inefficiency of production and I denotes the number of firms.

3.2.2 Empirical analysis

Following Saleem (2007) and Domah (2002) this study used DEA and SFA methods in the analysis.

I. Stochastic frontier Analysis

Battese and Coelli (1995) specify a stochastic frontier production function for panel data as;

$$Y_{it} = \exp\,(x_{it}\beta + v_{it} - u_{it}) \qquad 3.25$$

where Y_{it} is the production of the i^{th}firm $(i = 1,2,\dots,N)$ at the t^{th} observation $(t = 1,2,\dots,T)$. x_{it} is a vector of inputs of production for the i^{th} firm at t^{th} observation. β is a vector of unknown parameters to be estimated. v_{it} are random errors and u_{it} are random variables associated with inefficiency. u_{it} is assumed to have a mean of $z_{it}\delta$ where z_{it} is a vector of explanatory variables associated with technical inefficiency and δ is a vector of unknown coefficients. The panel does not need to be balanced (Battese and Coelli 1995).

Following Saleem (2007) and Domah (2002), and assuming a transcendental logarithmic transformation due to its advantage of not placing any restrictions on substitution possibilities in the production technology (Christensen and Green, 1976). The function representing the underlying technology of power generating plants was specified as

$$\begin{aligned} lnq_{it} &= \beta_0 + \beta_1 \ln k_{it} + \beta_2 \ln l_{it} + \beta_3 \ln f_{it} + \tfrac{1}{2}\big[\beta_{11}\big(\ln {k_{it}}^2\big) + \\ &\beta_{22}\big(\ln {l_{it}}^2\big) + \beta_{33}\big(\ln {f_{it}}^2\big)\big] + \beta_{12} \ln k_{it} \times \ln l_{it} + \beta_{13} \ln k_{it} \times \ln f_{it} + \\ &\beta_{23} \ln l_{it} \times \ln f_{it} + v_{it} - u_{it} \qquad 3.26 \end{aligned}$$

where q_{it} = Units generated by the ith plant in month t in MWh

k_{it} = Installed capacity for the ith plant in month t in MW

l_{it} = number of employees for the ith plant in month t

f_{it} = fuel used by the ith plant in month t in liters

$i = 1 \dots 27$

$t = 1 \dots 30$

ln is the natural log

$\beta_0 \dots \beta_{33}$ are parameters to be estimated,

v_{it} are random errors

μ_{it} are the random variables associated with inefficiency

μ_{it} are assumed to be independently distributed. The distribution of μ_{it} is truncated at zero of the normal distribution with a mean of m_{it} and a variance of σ_μ^2, that is $N(m_{it}, \sigma_\mu^2)$ (Battese and Coelli, 1995)

$$m_{it} = \partial z_{it} \qquad 3.27$$

where z_{it} is a vector of variables likely to influence the efficiency of the firm and ∂ are the parameters to be estimated.

In this study equation 3.24 took the form

$$m_{it} = \partial_1 age_{it} + \partial_2 grid_{it} + \partial_3\, ownership_{it} \qquad 3.28$$

where, *age* = number of years the plant has been in operation

Grid = whether on grid connected or not (on-grid = 1 and isolated = 0)

Ownership = whether public of privately owned (public =1, private = 0)

Estimation of equation 3.23 including determinants of inefficiency as specified in equation 3.25 was undertaken using the suggested method and commands in STATA by Belotti et al. (2013).

A Likelihood Ratio (LR) test was undertaken to test whether model 3.23 represents the data well. The LR test has chi-square distribution (Ngui, 2008). The null hypothesis is rejected if the LR statistics exceeds the critical values (Coelli et al., 2005). If the null hypothesis H_0: $\beta_{11} = \beta_{22} = \beta_{33} = \beta_{12} = \beta_{13} = \beta_{23} = 0$ is rejected, then the data is well represented by a tranlog model.

Elasticities and returns to scale

The partial elasticity of output with respect to each of the inputs E_k in equation 3.23 can be specified as in Saleem (2007) and Ngui (2008).

$$E_k = \frac{\partial lnq_{it}}{\partial lnx_k} = \beta_k + \beta_{kk} lnx_{kit} + \sum_{j \neq k} \beta_{kj} \, lnx_{jit} \quad k = 1, 2, 3; j = 1,2,3 \qquad 3.29$$

and x represents k, l and f in equation 3.23.

The returns to scale was calculated from the sum of the partial input elasticities, and expressed as

$$RTS = \sum_{k=1}^{K} E_k \qquad 3.30$$

II. DEA Malmquist productivity index

This study followed Saleem (2007) and Domah (2002) and included variables likely to affect the efficiency of plants.

Consider I firms that transform a set of inputs $x \in R_+^n$ into outputs $q \in R_+^m$, and each firm uses $x^{it} = x_1^{it}, \dots, x_n^{it}$ inputs to produce $q^{it} = q_1^{it}, \dots, q_m^{it}$ outputs, with $i = 1, \dots, I_t$ observations over $t = 1, \dots, T$ period of time. Following Coelli (1996a), Domah (2002) and Saleem (2007) output[7]- based Malmquist productivity change index was specified as follows;

$$m_0(q_{t+1}, X_{t+1}, q_t, X_t) = [m_0^{t+1}(q_{t+1}, X_{t+1}, q_t, X_t)\ X\ \ m_0^t\ (q_{t+1}, X_{t+1}, q_t, X_t)]^{\frac{1}{2}} \qquad =$$

$$\left[\frac{\boldsymbol{d_0^t\ (X_{t+1}, q_{t+1})}}{\boldsymbol{d_0^t(X_t, q_t)}}\ \boldsymbol{X}\ \frac{\boldsymbol{d_0^{t+1}(X_{t+1}, q_{t+1})}}{\boldsymbol{d_0^{t+1}(X_t, q_t)}}\right]^{\boldsymbol{1/2}} = \frac{\boldsymbol{d_0^{t+1}(X_{t+1}, q_{t+1})}}{\boldsymbol{d_0^t(X_t, q_t)}} \left[\frac{\boldsymbol{d_0^t\ (X_{t+1}, q_{t+1})}}{\boldsymbol{d_0^t(X_t, q_t)}}\ \boldsymbol{X}\ \frac{\boldsymbol{d_0^{t+1}(X_{t+1}, q_{t+1})}}{\boldsymbol{d_0^{t+1}(X_t, q_t)}}\right]^{\boldsymbol{1/2}} \quad 3.31$$

Where d was the distance function from the frontier, superscript t represented period t technology, superscript $t+1$ represented period t+1 technology, subscript o represented an output function.

Equation 3.27 represented the productivity of production point (X_{t+1}, q_{t+1}) relative to the production point (X_t, q_t). A value greater than 1 indicated total factor productivity growth from period t to $t+1$ (Coelli, 1996a).

The ratio outside the brackets was,

$$\frac{d_0^{t+1}(X_{t+1}, q_{t+1})}{d_0^t(X_t, q_t)} = efficiency\ change \qquad 3.32$$

and the ratio inside the brackets was,

$$Technical\ change = \left[\frac{d_0^t\ (X_{t+1}, q_{t+1})}{d_0^t(X_t, q_t)}\ X\ \frac{d_0^{t+1}(X_{t+1}, q_{t+1})}{d_0^{t+1}(X_t, q_t)}\right]^{1/2} \qquad 3.33$$

Following Saleem (2007) and Domah (2002), inputs were assumed to be the firm installed capacity in MW, number of employees and fuel in litres. Output of the firm was assumed to be units generated (MWh). Variables that are likely to explain technical inefficiency were also included as output. The variables include the age of the plant, dummy for grid or isolated and dummy for public or private ownership. DEAP Version 2.1 program developed by Coelli (1996a) was used to estimate the technical efficiency change (relative to CRS technology), technological change, pure technical efficiency

[7] The output-based model was used due to the fact that the capacity of the power plants is fixed, such that the power plants may produce as much output as possible given a fixed quantity of resource.

change (relative to VRS technology), scale efficiency change and total factor productivity change.

Data type, source and measurement

The data consisted of monthly records for all the 27 thermal generators existing in the system in the period July 2015 to December 2017. The period was informed by the available data from ERC, which coincided with the period they started the gazzettment of the fuel costs passed on to electricity consumers. The data was unbalanced since some of the plants were retired or not dispatched in some of the months. The data was from grid connected thermal generators and isolated stations that served areas not connected to the Grid. All the 19 isolated stations were owned by public sector utilities, 2 by KenGen and 17 by KPLC. 2 of the grid connected thermal generators belonged to KenGen while the remaining 6 were owned by independent power producers or private companies.

Table 3.2: Description and measurement of variables used to estimate efficiency

Variable	**Definition and measurement**	**Source of variable and data**
q	This is the total energy generated (MWh) for each plant in a month	Saleem (2007), Domah (2002), Fatima and Barik (2012) and Vijai (2018) ERC
k	The installed generation capacity (MW)	Fatima and Barik (2012) and Vijai (2018) ERC
l	This is the total number of employees in each of the plant	Domah (2002) IPPs, KenGen and KPLC
f	Fuel consumed in litres per month.	Saleem (2007) and Domah (2002) ERC
t	Month of the observation involved.	ERC
age	Years the plant has been in operation from commissioning.	Marmolejo and Rodríguez (2015) KPLC
$grid$	1 represents a grid connected plant, 0 an isolated plant	Domah (2002)
$ownership$	1 represents a public owned plant, 0 a private company	Saleem (2007)

Source: Author

3.3 Estimation results and discussion

Partial productivity analysis

Partial productivity analysis for grid and isolated power projects were analysed for the period July 2015 to December 2017. Capital, labour and fuel productivity was analysed.

Labour productivity

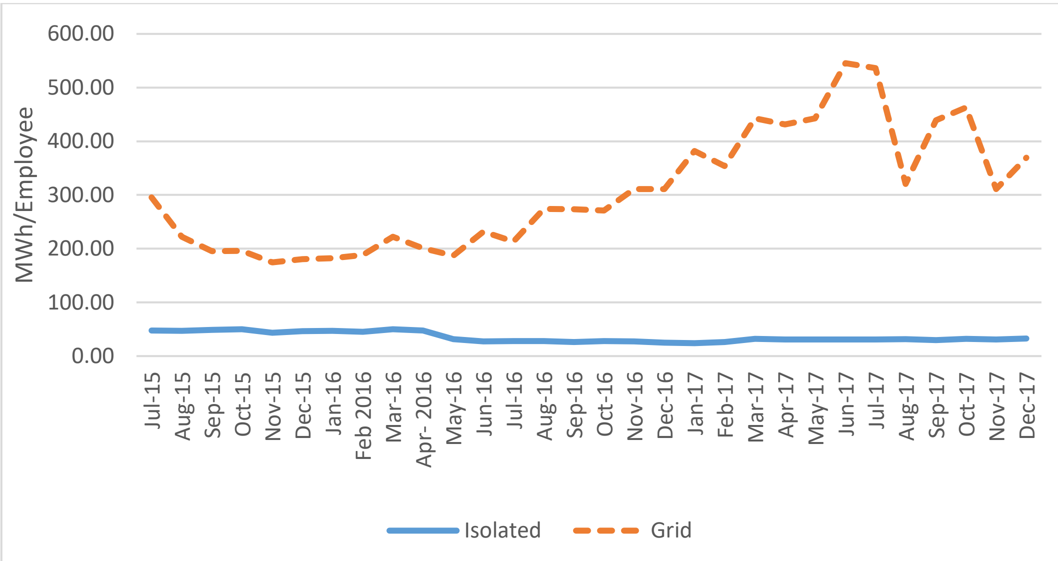

Figure 3.1: Labour productivity in electricity generation

Source: Author's estimation from ERC, KenGen, IPPs and KPLC data

Figure 3.1 presents the labour productivity in the generation of electricity. Labour productivity for grid connected projects was more volatile than that for isolated projects. This can be attributed to changes in monthly generated output. Grid connected power plants generated power based on economic merit order. Thus, competitively priced plants were allowed to generate first (Electricity Regulatory Board, 2005). The existence of other competing forms of generation may have caused the variability in energy generated from thermal plants. Thermal power plants tend to be more expensive than hydro and geothermal depending on the price of fuel. Labour productivity increased from July 2016 due to increased use of thermal power plants occasioned by inadequate rains in the period.

Capital productivity

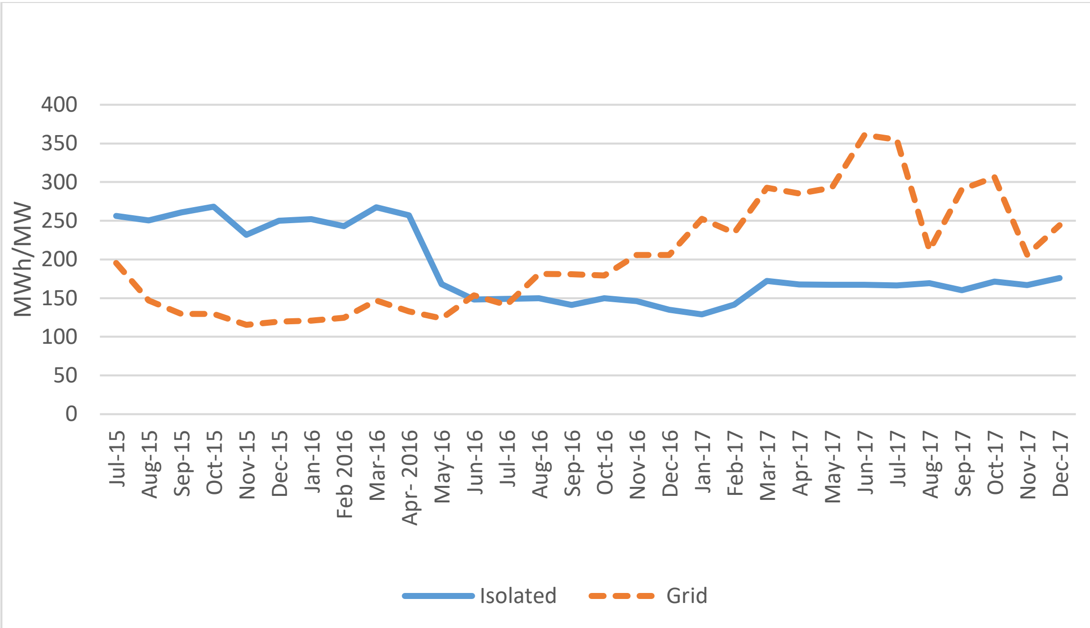

Figure 3.2: Capital productivity in electricity generation

Source: Author's estimation from ERC, KenGen, IPPs and KPLC data

As presented in Figure 3.2, the capital productivity fluctuated in both grid and isolated power plants. The capital productivity increased in the grid connected plants from July 2016 to June 2017. This can be attributed to increased use of thermal power plants in the 2016/17 financial year following inadequate rains that reduced hydro inflows affecting generation from hydro power plants.

Fuel productivity

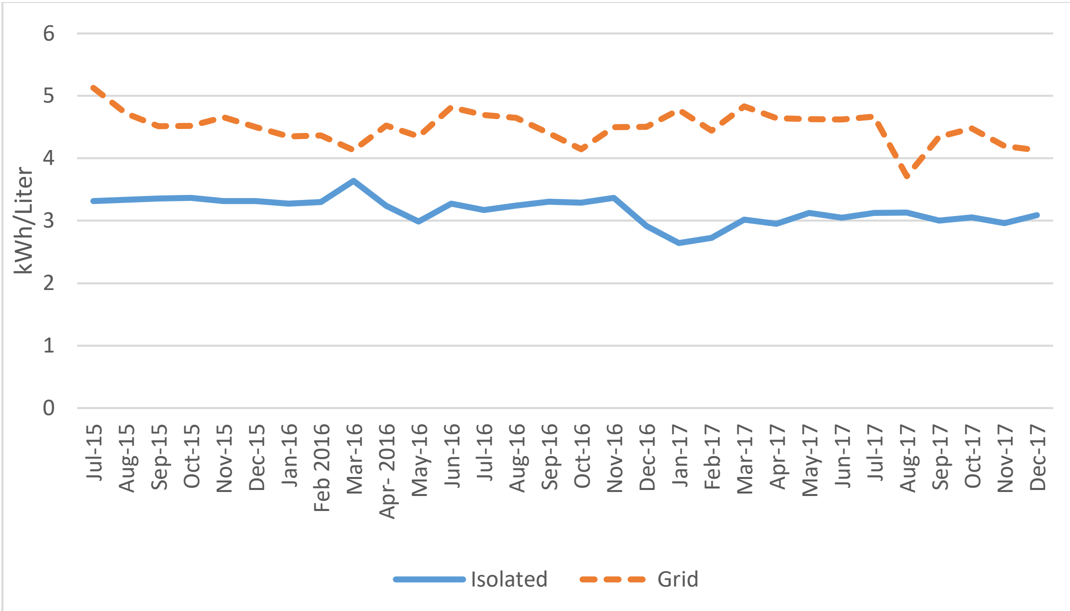

Figure 3.3: Fuel productivity in electricity generation

Source: Author's estimation from ERC, KenGen, IPPs and KPLC data

The fuel productivity remained less volatile over the period for both grid and isolated power plants. This could be attributed to power plants adherence to the fuel efficiency targets set by the regulator. The regulator issued specific fuel consumption targets in kg/kWh for each of the power plants (Electricity Regulatory Board, 2005). Power plants that missed their targets were not compensated for the fuel costs above the set targets.

3.3.1 Efficiency scores of thermal power generators in Kenya using Stochastic frontier analysis

Summary statistics

Table 3.3 Summary statistics for generating plants

Variable	Unit of measurement	Mean	Std. Dev.	Min	Max
Combined Grid connected and power plants - Total number of observations 742					
Output	MWh	6,033.71	12,827.57	3.06	66,308.00
Capital	MW	29.07	42.16	0.36	120
Labour	No of employees	22.94	26.65	4	98
Fuel	Liters	1,355,037	2,810,675	3,258	14,259,785
Age	No of years	7.54	5.80	1	27
Grid connected power plants - Total number of observations 234					
Output	MWh	18570.870	17098.480	166.21	66308
Capital	MW	89.776	15.653	73.5	120
Labour	No of employees	59.231	17.176	42	98
Fuel	Liters	4117495	3728143	40366	14300000
Age	No of years	9.774	7.05	1	21
Isolated power plants - Total number of observations 508					
Output	MWh	258.724	415.089	3.06	2679.91
Capital	MW	1.107	1.209	0.36	7
Labour	No of employees	6.222	3.785	4	23
Fuel	Liters	82566.56	118364.40	3258	755614
Age	No of years	6.512	4.789	1	27

Source: Author’s estimation from ERC, IPPs, KenGen and KPLC data.

The summary statistics for the variables used in the analysis are presented in Table 3.3. Total number of observations totalled to 742. Of these 234 were for grid connected plants while the remaining 508 observations were for isolated power plants. Isolated power plants are in areas not connected to the grid. The capacity of the power plants varied from 0.36MW to 120MW. The small capacity power plants of 0.36MW are isolated power plants. These power plants are Takaba, Eldas, Rhamu, Laisamis, North

Horr and Lokori. The largest power plant is Kipevu diesel plant 3. The average generated energy was 6,033.7GWh with a standard deviation of 12,827.6GWh. The high standard deviation could be attributed to the varying size of the power plants and the amount of energy generated by the plants per month. The minimum amount of energy 3.06GWh, was generated by North Horr, a 0.364MW isolated power plant in the month of February 2016. The maximum amount of energy of 66,308GWh was generated by Rabai power, a 90MW power plant in the month of July 2017. Number of employees averaged 23. The minimum number of 4 employees was associated with 11 isolated power plants. Iberafrica a 108.5MW power plant had the most numbers of employees (98). The least amount of fuel used was 3,258 liters by Lokori isolated power plant in the month of June 2016. Rabai power plant used the most fuel, 14,259,785 liters in July 2017. This is the same period the power plant generated the most energy. The average fuel used was 1,355,037 liters with a standard deviation of 2,810,675. The high standard deviation could also be attributed to the size of the power plants. Age of the power plants varied from 1 year to 27 years. The oldest power plant was 2.9MW Lamu island power plant while the youngest were 1 year having been commissioned in 2015. These plants include; Laisamis (0.36MW), North Horr(0.36MW), Lokori (0.36MW), Gulf (80.32MW) and Triumph (83MW). The SFA used the data in log forms, Table B.1 in the appendix presents the summary statistics of the plants after the logarithmic transformation.

Likelihood ratio (LR) test

The Likelihood ratio (LR) test that tested the null hypothesis H_0: $\beta_{11} = \beta_{22} = \beta_{33} = \beta_{12} = \beta_{13} = \beta_{23} = 0$ was found to be LR chi2(7)=65.65 indicating the data was well represented by the translog production model in equation 3.23. The p value was 0.000 indicating that $\beta_{11}, \beta_{22}, \beta_{33}, \beta_{12}, \beta_{13}, \beta_{23}$ are significantly different from zero.

Elasticities and returns to scale of thermal power generation in Kenya

Three estimates were undertaken, one for all thermal generators, and the other two separating estimates for grid connected generators and isolated generators. This allowed for the assessment of the differences in the results. Grid connected plants were larger in size compared to the isolated power plants. Partial elasticities were estimated using equation 3.26 and the returns to scale using equation 3.27. Table 3.4 presents the results of the three estimates.

Table 3.4: SFA estimates of elasticities of thermal power production in Kenya

Variable	Combined grid and isolated power plants	Grid connected power plants only	Isolated power plants only
Constant	-8.379*** *(1.323)*	-26.457*** *(6.278)*	-9.896 *(6.727)*
Capital	-0. 093 *(0.399)*	0.596* *(5.162)*	-0.536 *(2.099)*
Labour	0.807 *(0.604)*	-1.232 *(3.879)*	0.433 *(1.499)*
Fuel	1.685*** *(0.169)*	1.742*** *(0.248)*	2.969** *(1.066)*
Returns to scale	2.4	1.11	3.94
Log likelihood ratio	126.6	166.7	173.4

Source: Author's estimation from ERC, KenGen, IPPs and KPLC data
Notes: *** indicates significance at 1% level, ** indicates significance at 5% level and * indicates significance at 10% level. Standard errors are in paranthesis

The estimates for all the generators indicated that the partial output elasticity with respect to fuel was positive and significantly different from zero. A similar result was reported for the separate estimates for grid and isolated power plants. This indicates that adding fuel by 1% to the generators is likely to increase the amount of electricity generated by 1.68% for all thermal plants, 1.74% for grid connected projects and 2.97% for isolated power plants while holding capital and labour constant. The estimates for grid connected power projects also found capital to be significant determinants of electricity generation. Increasing capital by 1% was also likely to increase the electricity produced by these power plants by 0.6% while holding labour and fuel constant. These findings are consistent with other studies. The study for India by Shanmugam and Kulshreshtha (2005) found fuel (coal) and capital to be the determinants of coal based generation. Saleem (2007) also found capital to be significant in determining thermal power generation in Pakistan.

All the three estimates indicated increasing returns to scale. This means the plants can generate more output to reach the optimal scale. The finding of increasing returns of 1.11 for grid connected power plants is close to that of Knittel (2002) study for US coal and natural gas power plants. The study found coal power plants to have mild increasing returns to scale of 1.0644 and natural gas plants to have constant returns to scale. The isolated power plants as well as the combined isolated and grid power plants estimates indicated stronger increasing returns to scale of 3.94 and 2.4 respectively. Strong increasing returns of 3.21 have been reported in Saleem (2007) study for Pakistan electricity generation sector.

Efficiency of thermal power generation in Kenya

The efficiency estimates for all the thermal generators and two separate estimates for grid connected generators and isolated generators are presented on Table 3.5, Table 3.6 and Table 3.7. As explained, the separate estimates for grid connected plant and isolated plants was occasioned by the sizing of the plants where grid connected plants were larger in size compared to the isolated power plants. The efficiency scores were predicted using equation 3.23 and Belotti et al. (2013) command in STATA.

Table 3.5: SFA average efficiency for all thermal power generators in Kenya

Name of power plant	**Average efficiency Score (%)**
HOLA	92.07
MARSABIT DIESEL	91.78
LODWAR DIESEL	89.58
HABASWENI	89.27
LOKICHOGIO	89.24
BARAGOI	89.12
MFANGANO	88.32
MERTI	87.65
LAMU	86.51
ELWAK	86.36
ELDAS	85.71
TAKABA	85.63
RHAMU	85.09
LAISAMIS	84.54
MANDERA DIESEL	84.27
LOKORI	83.56
GARISSA(KENGEN)	82.50
NORTH HORR	79.72
WAJIR	76.71
RABAI	40.26
IBERAFRICA	38.97
TSAVO	38.29
GULF POWER	37.51
KIPEVU 1	36.42
TRIUMPH POWER	34.83
KIPEVU DIESEL PLANT 3	34.34
THIKA POWER	33.70

Source: Author's estimation from ERC, KenGen, IPPs and KPLC data

Average efficiency scores for all the thermal plants are presented in Table 3.5. The mean efficiency score for all the thermal power plants was found to be 71.06% indicating inefficiency in the thermal industry. None of the plants was found to be efficient. The technical efficiency scores ranged from 16.43% to 99.94%. The lowest efficiency score is associated with Iberafrica plant in the month of May 2016. Thika power was found to be the least efficient power plant with an average score of 33.7%. Iberafrica and Thika power are both grid connected power plants. The low efficiency levels could be attributed to increased use of geothermal and hydro power plants that decreased the use of grid connected thermal power plants by 27.6% (KPLC, 2016). The highest efficiency score was associated with Kipevu 1 power plant in the month of July 2015. Hola was the most efficient with an average score of 92.07%. However, this result should be interpreted with caution as all the isolated power plants were found to be more efficient than grid connected plants. These necessitated separate estimates of grid connected and isolated power plants.

Table 3.6: SFA average efficiency for grid connected thermal power generators in Kenya

Name of power plant	**Average efficiency Score (%)**
IBERAFRICA	99.75
TSAVO	99.68
KIPEVU1	99.62
RABAI	99.38
THIKA POWER	98.56
GULF POWER	97.94
TRIUMPH	97.87
KIPEVU3	97.30

Source: Author’s estimation from ERC, KenGen, IPPs and KPLC data

The efficiency score for grid connected power plants are presented in Table 3.6. Iberafrica was also the most efficient grid connected power plant with a mean efficiency score of 99.75%. The least efficient power plant was found to be Kipevu 3 with a mean efficiency score of 97.30%. Iberafrica is a privately owned power plant while Kipevu is owned by KenGen, a public utility. Iberafrica is also located close to Nairobi, a region which is currently the largest load center increasing its utilization. Kipevu is located in Mombasa where three other thermal power plants (Rabai, Tsavo and Kipevu 1) are located; this may have affected its power usage. The average efficiency score estimates for grid connected plants was found to be 98.78%. None of the power plants was found to be efficient. The lowest efficiency score of 76.58% was reported by Kipevu 3 power plant for the month of October 2016. The highest efficiency score of 99.76% was reported by Iberafrica for the month of July 2017. This could be attributed to a period characterised by poor hydrology occasioned by inadequate rains that increased the use of thermal power plants to meet the demand (KPLC 2016).The efficient scores are within the range of other studies in literature. For example, Saleem (2007) study for Pakistan finds the average efficiency score to be 78%, Viraj (2018) study for India estimates an average efficiency score of 88.2%. Others are Chang and Toh (2007) who finds the average efficiency for Singapore score to be 90.35% using SFA and 98.33% using DEA.

Table 3.7: SFA average efficiency for isolated power plants in Kenya

Name of power plant	**Average efficiency Score (%)**
GARISSA	94.53
LAMU	91.86
LOKICHOGIO	91.85
LODWAR	91.70
MERTI	91.31
HOLA	90.98
BARAGOI	89.69
HABASWENI	88.52
MARSABIT	88.46
MANDERA	87.89
MFANGANO DIESEL	86.59
TAKABA DIESEL	85.30
ELWAK	83.80
RHAMU	83.25
ELDAS	81.47
WAJIR	79.75
LAISAMIS	70.49
LOKORI	65.41
NORTH HORR	38.55

Source: Author’s estimation from ERC, KenGen, IPPs and KPLC data

Table 3.7 presents the efficiency scores for isolated power plants. The most efficient isolated power plant was found to be Garissa with an average efficiency score of 94.53%. This was the largest isolated power plant with an installed capacity of 6.7MW. The least efficient plant was North Horr with a mean efficiency score of 38.55%. The average efficiency for isolated power plants was estimated to be 82.73%. The least efficiency score of 13.13% was reported by Lokori power plant in the month of November 2015. The highest efficiency score of 98.48% was reported by Hola plant in the month of December 2015. The technical efficiency scores fall within the range of estimates from other studies. Domah (2002) study for island power plants in the USA finds the average efficiency score to be 35%.

The estimates from combined grid and isolated plants were different from the results realised from estimating grid and isolated plants separately. Grid connected power plants were found to be more efficient when estimated separately from isolated plants. This finding agrees with that of Domah (2002) that found interconnected power plants to be more efficient compared to isolated islands. This can be attributed to the small sizes of the isolated power plants relative to the grid connected power plants. Further, the isolated power plants are limited to the energy requirements in their regions of supply.

Determinants of efficiency of thermal power generation in Kenya.

The one-step estimation of determinants of technical efficiency was used in-line with Battese and Coelli (1995) model. Belotti et al. (2013) commands in STATA were used to implement the model. The results of the determinant of efficiency are presented in Table 3.8.

Table 3.8: Effects of age, connection and ownership on technical efficiency of thermal power plants in Kenya

Variables	Combined grid connected and isolated plants	Grid connected power plants	Isolated power plants
Age	-0.0026034** *(0.002)*	-0.0042498 *(0.066)*	-10.25921*** *(0.199)*
Grid- on-grid = 1	0.6402017*** *(0.022)*		
isolated = 0	0.1388421		
Ownership public =1	-0. 1106151*** *(0.025)*	-0.0362599 *(0.341)*	
private = 0	0.1388421	0.0422385	

Source: Source: Author's estimation from ERC, KenGen, IPPs and KPLC data

Notes: *** indicates significance at 1% level, ** indicates significance at 5% level and * indicates significance at 10% level.

Age, grid and ownership were found to be significant determinants of technical efficiency in the combined grid and isolated plants estimates. Age had a negative sign for all the power plants, including the isolated power plants, indicating that age is likely to reduce the efficiency of generating plants. This finding is consistent with the suggestion by Marmolejo and Rodríguez (2015) that ageing of power plants increases the wear and tear affecting their efficiency.

Grid connection was found likely to have a positive effect on efficiency. This is consistent with the finding of Domah (2002) that found interconnected power plants to be more efficient than isolated power plants. In Kenya, isolated power plants efficiency could also be affected by limited energy demand in their regions of supply.

Public ownership had a negative sign indicating the possibility that public ownership is likely to reduce the technical efficiency of the power plants. The finding on negative relationship between efficiency and public ownership is consistent with that of Saleem

(2007). Larger isolated power plants, Garissa and Lamu, were found to be more efficient, this finding is also supported by the findings in Domah (2002).

3.3.2 DEA Malmquist index results

The Malmquist index indicates improvement or deterioration of performance. The summary estimates of equation 3.28 using DEAP version 2.1 computer program are presented in Table 3.9 while Table B.2 in the appendix shows the detailed index for all the firms. The same sample data was used, but to ensure a balanced panel 6 plants were dropped. The plants had either been retired, not dispatched or commissioned between the period July 2015 – December 2017. These plants include Gulf power, Garissa, Lamu, Hola, Laisamis, North Horr and Lokori.

Table 3.9: Malmquist Efficiency change

Power Plants	Technical Efficiency Change (Relative to CRS technology)	Technological change	Pure Technical Efficiency Change (Relative to VRS technology)	Scale Efficiency Change	Total factor productivity change
Combined grid and isolated power plants	1.002	1.000	1.000	1.002	1.003
Grid only	1.01	0.991	1.006	1.003	1.001
Isolated Only	1.001	1.004	0.999	1.002	1.006

Source: Author's estimation from ERC, KenGen, IPPs and KPLC data

In the estimates that combined both grid and isolated plants, technical and scale efficiency change was 1.002 indicating an improvement in efficiency of about 0.2%. Total factor productivity was also found to have improved by 0.3%. There was no technological change in the period. This could be attributed to the short period under consideration in the study.

The estimates for grid connected power plants found technical efficiency change, when assuming constant returns to scale (CRS[8]) technology, to have improved by 1%. This was slightly higher than the 0.1% realised for isolated power plants. Technical efficiency change assuming variable returns to scale (VRS) situation was found to have improved by 0.6% for grid connected power plants. Isolated power plants efficiency change relative to VRS technology reduced by 0.1%. The scale efficiency was also estimated to have improved by 0.3% for grid connected power plants and 0.2% for isolated plants. Technological change favoured isolated power plants with an improvement of 0.4% compared to grid connected power plants that reduced with 0.9%. Technological change represents a frontier shift (Domah, 2002). The inward shift in the grid connected plants could be attributed to the growth in the grid energy mix bringing in competition and affecting the use of the thermal power plants. The outward shift in the isolated could be attributed to demand growth in their locations. Consequently, isolated power plants experienced more increased total factor productivity of 0.6% compared to the grid connected power plants growth of 0.1%.

Efficiency, technical and TFP changes were less than estimates reported in reviewed literature such as Saleem (2007), Domah (2002) and Arocena and Waddams (2002). This can be attributed to the short time span of 30 months considered in this study, the studies in literature analysed data of over 6 years. Nevertheless, the plants showed improvement in technical efficiency despite none of them being found to be efficient. Saleem (2007) study for Pakistan agrees with this finding.

3.4 Summary and conclusions

This essay analysed the technical efficiency of thermal power plants in Kenya using data from ERC. The panel data was for 27 power plants over the period July 2015 to December 2017. First the technical efficiency of all the power plant was estimated using SFA. Separate estimate for the 19 isolated power plants and 8 grid connected power

[8] CRS assumes all the plants are operating at an optimal scale (Coelli 1996)

plants were also undertaken. To assess the change in efficiency over the 30 months, DEA Malmquist index was undertaken for all the power plants and separately for grid and isolated power plants.

The mean efficiency score for all the power plants (combined grid and isolated power plants) was found to be 70.62%. Grid connected power plants efficiency averaged 98.78% while that of isolated power plants was found to be 82.73%. None of the power plants was found to be efficient. This indicated that the thermal power industry in Kenya was inefficient and underutilised its technical potential. The Malmquist index indicated improvement in efficiency and productivity. The estimated efficiency change for combined grid and isolated power plants was found to be 0.2% with a total factor productivity growth of 0.3%. Estimates for grid connected power plants found efficiency improvements of 0.6% and total factor productivity of 0.1%. Technological change was found to be 0.991, indicating a possible inward frontier shift for grid connected power plants. Isolated power plants were also found to have experienced efficiency improvement of 0.2% and total factor productivity of 0.6%.

The SFA estimates indicated that fuel has a positive elasticity and is significantly different from zero for the three estimated models that is combined grid and isolated plants, grid connected plants and isolated plants. Capital was also found to be a positive and significant determinant of electricity production for grid connected power plants. The return to scale results indicated increasing returns to scale. Age, grid and ownership were found to be significant determinants of the technical efficiency. Age and public ownership coefficients had a negative sign indicating they were likely to reduce the efficiency of generating plants. Grid connection had a positive sign indicating grid connection had a positive effect on efficiency. Age was also found to negatively determine the efficiency of isolated power plants.

3.5 Policy recommendations

Efficiency requires the government to deepen reforms, competition and regulations. Reforms meant to achieve efficiency in the sector have not realised this objective yet as thermal power generation industry still showed inefficiency. The government should continue with the reform agenda and particularly consider encouraging private investment in power generation. The government should also continue connecting the isolated areas to the grid. Areas not connected to the grid have the potential of benefiting from private owned generation plants.

The industry is operating on increasing returns to scale. This finding is critical as it indicates capacity to improve performance in the sector. With the same inputs currently being deployed output could be expanded. ERC should therefore consider using the findings of this paper to implement incentive regulation by rewarding or penalising thermal power plants based on their performance relative to other firms. Removing the current protection accorded to the generators in the long term take or pay power purchase agreements is likely to improve on the plants efficiency. This can be done through the introduction of a wholesale generation market and signing take and pay contracts.

The fuel elasticity of output was found to be high and significant. ERC can look at how to regulate fuel use whose costs are currently passed on to consumers leaving the generators with a minimal risk on it. Generators may not be motivated to use it efficiently. ERC could explore the possibility of reducing the cost of fuel transferred to consumers with a view to make generators use the same fuel amount to produce more energy. This could be done by downward revision of the specific fuel targets per unit generated.

3.6 Contribution of the study

This study is a first attempt to estimate the technical efficiency of power generating plants in Kenya. This contributes to knowledge on the efficiency levels of the thermal power generating companies in the country.

The study also contributes to policy by providing a mechanism that ERC can use for incentive regulation of electricity generating power plants and other electricity entities. The findings indicate private ownership and grid connection positively affected efficiency. This is important in informing future reforms in the country.

3.7 Limitation of the study

The 1997 reforms that allowed unbundling of generation from transmission and distribution also allowed for private participation investment in generation. Most of the private investments after the reforms were mainly in thermal power plants. For this reason, this study focused on thermal power plants to ensure a comparison of the same technology. The lengthy of the available data at ERC was also limited to allow for a good measure of efficiency and productivity change.

3.8 Areas for further research

The government has several planned generation projects to be implemented by both private and public companies. The implementation of these projects will overtime allow sufficient data for an efficiency analysis of other generation technologies such as geothermal, hydro, wind and solar. Further reforms in distribution are envisaged with the government allowing participation of private entities in distribution as well as in isolated areas. This will allow for efficiency studies in the distribution of electricity.

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CHAPTER 4

EXPLAINING ELECTRICITY TARIFFS IN KENYA

Abstract

Kenya has been struggling with the twin problem of reducing electricity tariffs while at the same time increasing supply. Several regulatory reforms introduced in the sector have not succeeded in lowering the electricity tariffs necessitating the need to investigate the push factors of tariffs. This study explained electricity tariffs by exploring the drivers of Kenya Power and Lighting Company (KPLC) tariffs, assessing the effects of reforms on the tariffs and the scale of operation of KPLC. Using cost time series data from KPLC for the period 1986 to 2016 and Autoregressive distributed lag model (ARDL) we estimated an average cost function of KPLC. The results indicated that in the short run average costs increased with price of labour and system losses, and decreased with output, change in the load factor, lagged load factor, lagged average cost, reforms and structural breaks. In the long run average cost of electricity increased with price of labour and system losses and decreased with output and system load factor. The average cost-output elasticity was negative an indication that KPLC was enjoying economies of scale. The electricity market should therefore retain the transmission and distribution segments as a natural monopoly. The main push factors for the rising power tariffs were found to be system losses and price of labour. The Ministry of Energy and the regulator should continue with reforming power supply to increase efficiency and reduce the system losses. This should be coupled with targets aimed at reducing the price of labour. The Ministry of Energy should also provide incentives aimed at increasing the system load factor. Such incentives can be in the form of special tariffs such as time of use tariffs. These measures will reduce electricity costs and bring down power tariffs.

4.0 Introduction

Prior to the reforms of 1997 the electricity sector had one vertically integrated utility Kenya Power and Lighting Company (KPLC) owned mainly by the government. At the time the utility was inefficient, lacked transparency and was declining in performance. The reforms process that unbundled generation from Transmission and distribution, and established an independent regulator was expected to rectify these problems. The reforms also created a framework for private sector participation in the generation of power (Godinho and Eberhard, 2019; Electricity Regulatory Board, 2005).

The second set of reforms were initiated in the Sessional Paper No. 4 of 2004 that also set the course for the Energy Act of 2006. The agenda was to build on the previous reforms and strengthen institutions so as to provide cost-effective, affordable and adequate electricity. The reforms strengthened the regulator and allowed for further unbundling of the sector. The Rural Electrification Authority (REA), Kenya Electricity Transmission Company (KETRACO) and Geothermal Development Company (GDC) were established (Godinho and Eberhard, 2019; Republic of Kenya, 2004). The establishment of an independent regulator with the mandate to set, review and adjust tariffs allowed for the Tariff Review Policy in 2005 (Godinho and Eberhard, 2019). The tariff policy details the consideration the regulator makes in deciding the KPLC retail tariff (Electricity Regulatory Board, 2005).

Electricity tariffs in Kenya are set by the Energy regulatory commission (ERC) now the Energy and Petroleum Regulatory Authority (EPRA) (Republic of Kenya, 2019). The tariffs are bundled so as to cover the operating costs of KPLC and the capital costs of generation, transmission, distribution and retailing (Godinho and Eberhard, 2019; AF-Mercados Energy Markets International (AF-Mercados EMI), 2018; Electricity Regulatory Board, 2005). The tariffs reflect KPLC’s revenue requirements. They are based on the total cost of KPLC (Godinho and Eberhard, 2019). Table 4.1 breaks down the KPLC revenue requirements as approved by the regulator for the 2018/19 financial year. Inflation, fuel costs associated with thermal power plants and foreign exchange rate fluctuations adjustment costs are not included in the preapproved total revenue requirements but are instead passed onto consumers once incurred due to their fluctuating nature (Electricity Regulatory Board, 2005).

Table 4.1: KPLC's revenue requirements for 2018/19

Item	**Unit**	**Amount**
Projected sales	GWh	9,294
Allowed Losses	%	14.9
Projected Energy purchased	GWh	10,922
Power purchase costs (Generation costs)	Kshs, 000	71,336,004
Transmission distribution and retailing costs	Kshs, 000	60,070,474
Total revenue requirements	Kshs, 000	131,406,478
Average Tariff (Without pass through costs)	Ksh/kWh	14.138

Source: ERC (2018)

The generation costs are as captured in the power purchase agreements (PPA) signed between KPLC and the generators. The costs include capacity charges that allow the developers to recover their investment costs; energy charges paid based on the amount of energy generated by the power plants and pass through costs that include fuel costs. The fuel costs rise with the amount of energy generated and the price of the fuel. Other generation associated costs include geothermal steam charge, water resource management levy, foreign exchange and inflation adjustment (AF-Mercados EMI, 2018). Transmission costs are incurred by Kenya Electricity Transmission Company (KETRACO) and KPLC. KETRACO costs are mainly in operation and maintenance of completed transmission assets. The KPLC transmission and distribution costs include operation, maintenance and depreciation of the assets in the company's audited books. KPLC's also has the retail supply service costs that includes customer administration metering, invoicing and collection (Electricity Regulatory Board, 2005). These total revenue requirements are subdivided amongst the different customer classes to form the retail tariff of each of the customer category. Table 4.2 presents the applicable tariffs for the various customer categories.

Table 4.2: Retail electricity tariffs for the various customer categories

Customer Type (Code Name)	Energy Limit kWh/ month	Charge Method	Unit	2013/14 Effective Dec 2013	2014/ 15	2015/ 16	2018/19 Effective July 2018	
Domestic		Fixed	KSh/month	120	150	150	N/A	
"	0-50	Energy	KSh/ kWh	2.50	2.50	2.50	0-100	10
"	51-1500	Energy	KSh/ kWh	11.62	13.68	12.75	>101	15.8
"	>1500	Energy	KSh/ kWh	19.57	21.57	20.57		
Small Commercial		Fixed	KSh/month	150	150	150	N/A	
							0-100	10
	<15,000	Energy	KSh/ kWh	12.00	14.00	13.50	>101	15.6
Comm./industrial	>15,000	Fixed	KSh/month	2,000	2,000	2,500	N/A	
		Energy	KSh/ kWh	8.70	9.45	9.20	12	
		Demand	KSh/ kVA	800	800	800	800	
Comm./industrial	No Limit	Fixed	KSh/month	4,500	4,500	4,500	N/A	
		Energy	KSh/ kWh	7.50	8.25	8.00	10.9	
		Demand	KSh/ kVA	520	520	520	520	
Comm./industrial	No Limit	Fixed	KSh/month	5,500	5,500	5,500	N/A	
		Energy	KSh/ kWh	7.00	7.75	7.50	10.5	
		Demand	KSh/ kVA	270	270	270	270	
Comm./industrial	No Limit	Fixed	KSh/month	6,500	6,500	6,500	N/A	
		Energy	KSh/ kWh	6.80	7.55	7.30	10.3	
		Demand	KSh/ kVA	220	220	220	220	
Comm./industrial	No Limit	Fixed	KSh/month	17,000	17,000	17,000	N/A	
		Energy	KSh/ kWh	6.60	7.35	7.10	10.10	
		Demand	KSh/kVA	220	220	220	220	
Off peak Interruptible		Fixed	KSh/month	120	150	150	N/A	
		Energy	KSh/ kWh	13.00	13.75	13.50		
Domestic Interruptible		Fixed	KSh/month	240	300	300		
Small Commercial Interruptible		Fixed	KSh/month	270	300	300		
Street Lighting	No Limit	Fixed	KSh/month	200	200	200	N/A	
		Energy	KSh/ kWh	10.50	11.25	11.00	7.5	

Source: ERC (2013; 2018)

Cost of electricity supply has been rising resulting in a general increase in the revenue requirements of KPLC and in the overall tariffs. Figure 4.1 shows the general increase in these costs. The increase is reflected in the retail tariffs in Table 4.2. Energy purchase costs contribute the most to the cost of power sold by KPLC. The share of the generation costs averaged 74% of KPLC's revenue requirements in the period 2007/8 – 2017/18. In the same period, network service costs associated with transmission, distribution and retailing service averaged 26%. The share of network service costs increased from 22% in 2007/08 (KPLC, 2008) to 32% in 2017/18 (KPLC, 2018).

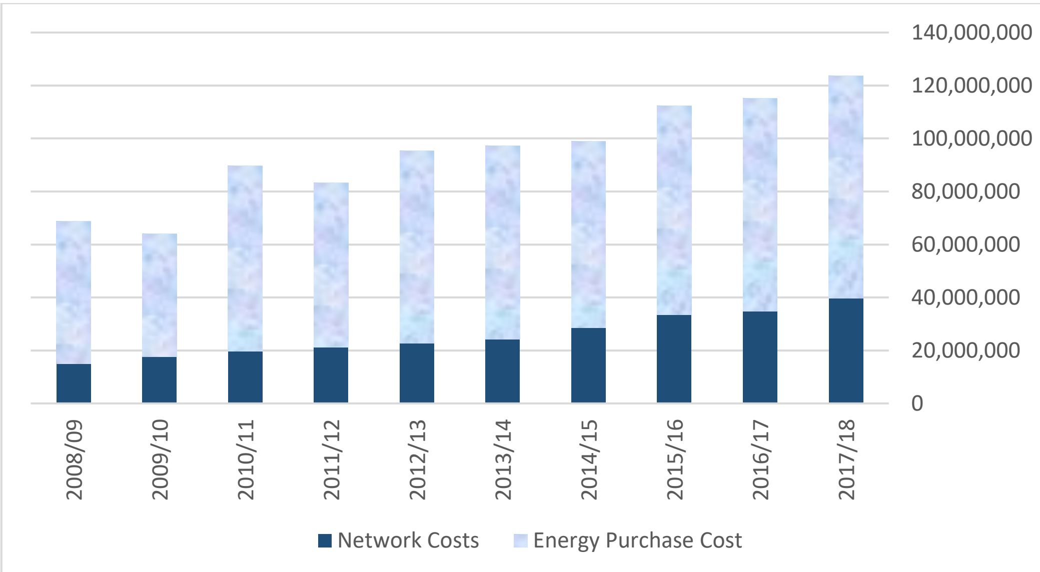

Figure 4.1: Cost of electricity 2008/09 – 2017/18 (KSh' 000)

Source: Author's compilation from various KPLC annual reports (2018)

Average tariffs increased from Kshs 12.6/kWh in June 2009 to kshs 15.9/kWh in June 2018 (KPLC, 2018). There is need to interrogate the costs build up in the overall tariff. First, generation costs are included in the tariff as energy purchase costs. The costs are as contained in the PPAs. PPAs once signed cannot be amended by law and this protects the generators even when they are inefficient. The contracts are long term on take-or-pay basis meaning KPLC has to pay the capacity charges whether it takes the power or not (Electricity Regulatory Board, 2005).

Another component in the bundled electricity tariff is network cost. KPLC is a natural monopoly undertaking the network functions (Electricity Regulatory Board, 2005). With the intention of protecting consumers and improving the welfare of electricity consumers ERC regulates KPLC tariffs using cost of service regulation. KPLC is allowed to charge tariffs that allow it to recover only its costs of supply. The costs are based on data provided by KPLC. The regulator reduces the information asymmetry by undertaking intensive financial analysis of the data provided by KPLC (Public utility research centre, 2012). The regulator also subjects any tariff adjustment application to public hearing and participation as required by the Constitution of Kenya (Republic of Kenya, 2010). ERC only makes a determination of the final tariffs after the public expresses itself on any proposed tariffs (Electricity Regulatory Board, 2005).

The other critical component explaining electricity tariffs is the electricity demand forecast. An unrealistic high demand forecast can result in underutilised power plants, which in turn increases electricity costs. In chapter two, the thesis provides an analysis of the official demand forecast and recommends the need to revisit the official forecast and the planned investments thereof. Network service costs associated with KPLC, a regulated natural monopoly remain the only segment in explaining electricity tariffs that hasn't been analysed so far in the thesis. There is need to understand the drivers of these costs. These would inform future regulatory interventions that could be contributing to excessive costs affecting the overall price. Understanding the tariff drivers can help improve cost observability with implications on welfare of electricity consumers. KPLC overall tariffs are expected to equal its average cost as is common with transmission and distribution companies (Kirschen and Strbac, 2004). Therefore, it is important to study the average cost of KPLC.

The government has been trying to provide quality, reliable, affordable and accessible supply of electricity. However, electricity tariffs have been rising. There is need to analyze the push factors behind electricity tariffs in the country. The proposed reforms in the Energy Act 2019 favour competition in the generation and retailing sections of power sector leaving the transmission, distribution and system operation sections as natural monopolies. It argues that it does not make economic, environmental and aesthetic sense to have competing transmission, distribution and system operation in one area (Republic of Kenya, 2019). This necessitates an investigation into the current monopoly pricing of electricity.

4.0.1 **Statement of the research problem**

The high electricity tariffs have affected affordability and access to electricity to a majority of the population in Kenya (Republic of Kenya, 2004). This has seen the Government introduce several reforms to reduce the tariffs. The reforms include unbundling generation from distribution and transmission of power, establishing an independent regulator and cost effective operation of the generation and distribution companies. Despite these reforms the retail electricity tariffs have remained high. In 2013 the Governement hoped to reduce the cost of electricity from 14.14 US cents to 9 US cents for commercial and industrial consumers and 19.78 US cents to 10.45 US cents for domestic consumers by the year 2017 (Republic of Kenya, 2013a). The target has not been realised with the average retail tariffs having increased from US cents 14.37/kWh in June 2013 to US Cents 15.92/kWh in June 2018 (KPLC, 2018). The government objective of reducing electricity tariffs while increasing access and supply has not been met. There is need to analyse why electricity tariffs have been rising. To address the increasing tariffs, there is need to investigate the key push factors of electricity costs in the country. There is also need to assess the effects of the over decade old reforms on the tariffs. The assessment needs to cover KPLC’s scale of operation with a view to determine whether there is need for other competitors in the distribution of power.

4.0.2 **Research questions**

The chapter attempted to answer the following question: What drives the power tariff in Kenya? The specific questions are; Should there be competition in distribution of power? What are the push factors of electricity tariffs?

4.0.3 **Objectives of the study**

The overall objective of these chapter was to explore the drivers of overall electricity tariffs in Kenya. The specific objectives were:

- To explain the push factors of KPLC electricity tariffs
- To analyse whether there is need to open distribution function of KPLCs to competition

4.0.4 **Significance of the study**

The findings of this chapter are of interest to consumers of electricity and the government. Both would want to know why electricity tariffs keep going up. The identification of the electricity cost push factors will assist reduce the information asymmetry between the regulator and KPLC and assists in designing appropriate efficiency targets for the monopoly. The model used in this study could be used by the regulator to predict the unit costs of KPLC, estimate network access costs and inform regulatory decisions. In the Energy Act of 2019, the government has proposed further reforms including among others retaining transmission, distribution and system operation as natural monopolies and allowing competition in generation and commercial function. The findings on the scale of operation of KPLC will inform the Ministry of Energy decisions in implementing the planned reform.

4.1 **Literature review**

4.1.1 **Theoretical literature**

The theory of the firm postulates profit maximization to be the motive behind firm behaviour. This motivates the firm to minimize costs weather they are monopolists, perfect competitors or in between. Perfect competition has it that a large number of sellers and buyers ensure none of them have the power to determine market price. A monopoly is the only seller and has power to determine the price or quantity in a market. Monopolies arise due to technological, financial or legal impediments to entry by others (Jehle and Reny, 2011).

There are cases where competition is seen as self-destructive and inefficient. This is the case of a natural monopoly. The firm is able to serve the entire market demand at a lower cost than would a combination of several smaller firms (Public utility research center, 2012). Kahn (1998) and Public utility research center (2012) cite the economic benefits of natural monopolies to include great economies of scale and their costs and prices depend on the rate at which the economy and its demand for their service grow. The costs of a single supplier are lower creating an efficiency case for monopolistic organization. Most of these industries are providing infrastructure services with high fixed and sunk costs and an inelastic demand. This creates the need for regulation to protect consumers from welfare loss as the monopoly attempts to maximise its profit. In electricity, transmission and distribution functions are identified as sectors that remains a natural monopoly (Laffont, 2005; Jamasb and Pollitt, 2004). This is because besides the economic rationale that inhibits competition, the government also influences the entry into the market, fixes prices, prescribes the quality and conditions of service and imposes obligation to provide services to all under reasonable conditions (Kahn, 1998).

The presence of a monopoly in an economy leads to social costs in form of welfare loss arising from the firm setting its price above the equilibrium and output below the competitive level (Gumus, 2006). Consumers are denied the surplus value they would derive from a competitive market (Posner, 1968). This lack of a competitive market entails a welfare loss as the monopoly attempts to maximize profits. The welfare loss arises when consumers pay a higher price than they would in a competitive market and when the monopoly reduces output or the consumers are unable to pay the uncompetitive price reducing their consumption (Posner, 1974; Gumus, 2006).

Requiring the monopoly to charge the competitive price would result in a deficit and make the firm financially insolvent. The consumers would also not gain any consumer surplus and in the long run there would be a welfare reduction compared with monopoly pricing. The society is better off if the firm is allowed to remain a natural monopoly and under appropriate regulatory policies such as provision of subsidies or average cost pricing (Berg and Tschirhart, 1988).

Regulation is instituted to protect the public interest and to correct for these market failures. These led to the introduction of public interest theory also referred to as theory of economic regulation (Stigler 1971; Posner, 1974). The theory is based on the assumption that government regulation is able to correct market failures associated with natural monopolies by controlling prices and imposing standards (Shleifer, 2005). Other regulatory direct controls include profits control, quality of service, entry into the business and extensions and abandonments of service and plant (Posner, 1968).

The regulators optimization problem is that of maximizing social welfare. Cost observability improves welfare as it allows more control over pricing (Laffont and Tirole, 1986). Cost service regulation involves provision of a return on prudent investments by the firm, prices are determined to be equal to the average cost, the prices remain fixed for the regulated period and the regulatory process involves checks and balance between the firm and the consumers with the regulator acting as an arbitrator (Laffont, 1994).

Shleifer (1985) notes that regulators adjust firm’s prices to equal the costs of providing service to consumers. This avoids welfare loss from monopoly pricing, but the allowed price is high enough to allow the firm to supply. However, this approach does not adequately address cost efficiency as the firms are aware that prices follow costs, and the costs are adjusted upwards or downwards with any rise or fall in costs (Posner, 1968). Shleifer (1985) proposes this be remedied using yardstick competition between identical firms. Where there are no identical firms such as KPLC in Kenya, the study proposes the use of cost data and firm specific characteristic to predict unit cost level for the firm. The regulator then uses the regression predicted costs to set the prices as opposed to the costs incurred by the firm.

The desire to regulate is also driven by the need to deal with the information asymmetry as well as to meet government objectives which sometimes differ with those of the utility. Regulators use competition, information gathering and incentive regulation to deal with the asymmetries in information and government objectives. Competition is introduced through market liberalization and facilitating competition (Public utility research center, 2012). However, this is only feasible if the demand and technology of supply allows, if demand can be supplied by one firm at lowest cost then the market is a natural monopoly (Posner, 1999). Information gathering involves collecting information on the market and operating statistics. Incentive regulation controls the overall price levels using rate of return or cost of service, price capping or yardstick regulation (Public utility research center, 2012). The regulatory process involves the determination of the overall revenue requirements based on the cost of service for the regulated firm, which is then used to determine the tariff schedule (Posner, 1968). The approach in Kenya’s power sector is similar as it is based on the costs of service regulation (Electricity regulatory board, 2005).

Cost drivers can be found by estimating a cost function. The cost function assumes that the firm aims at minimizing costs while the cost frontier is based on best practice technology (Saal et al, 2013). The cost function is domiciled in the theory of the firm. Jehle and Reny (2011) indicate that a firms’ cost of output is exactly the expenditure it must make to obtain the inputs used to produce the output. If a firm’s objective is to maximize profits it will inevitably choose the least costly or cost minimizing production plan for every level of output. This will be true for all firms whether monopolist or perfectly competitive. Cost minimization is achieved when the marginal rate of substitution of two inputs is equal to the ratio of their prices (Jehle and Reny, 2011). Also, the slope of the isoquant line is equal to the slope of the isocost line (Jehle and Reny, 2011 and Baye,2010).

In the short run firms face a restricted cost function (Jehle and Reny, 2011). A firm is able to choose some but not all inputs optimally. The short run cost function gives cost of producing output when variable factors are being used in a cost minimizing way (Baye, 2010). Short run and long run costs coincide for some level of output. According to Jehle and Reny (2011) the long run cost curve is the lower envelope of the family of the short run cost curves.

Joskow (2005) identifies the characteristics of a natural monopoly to be a declining average cost with respect to output. Also, when a firm's average cost declines as its output expands its production technology is characterised by economies of scale. Therefore, the concept of natural monopoly is related to the economies of scope and scale (Filippini and Farsi, 2008). According to Kahn (1998) this tendency is mostly attributed to the need for such companies to make large investments in order to meet their customers demand. Varian (1996) and Kirschen and Strabac (2004) show that for natural monopolies with huge fixed costs and minimal marginal costs, pricing based on marginal cost may result in the firm making losses. In such cases the regulator should set the price at the point of intersection between the demand and average costs curves. But this results in the firm producing output that is less than the efficient level of output. The price just allows the firm to break-even.

Roberts (1986) identifies the complexity of measuring output expansions for transmission and distribution companies due to the geographic distribution of customers. Consequently, the study develops three measures of economies of density and size. The measures are based on the assumption that the firm has three outputs expansion; energy, number of customers and service area. The first measure is economies of output density which measures the cost effect of an equal proportionate increase in outputs. The second measure is the economies of customer density which arise when the number of customers per square mile and quantity of output increase but output per customer remains fixed. The third measure is the economies of size which is the change in cost due to increase in the size of the firms' service area while holding output and number of customers fixed. Economies of output density estimates are based on the elasticity of total cost with respect to output. Economies of customer density are estimated based on the elasticity of total cost with respect to cost, holding total output fixed. The economies of size are based on the estimated change in cost due to increases in the size of the firm's service area while holding level of output and number of customers fixed. These measures have been implemented by several recent studies; namely; Al-Mahish, (2017); Filippini, Wild and Kuenzle, (2002); Filippini and Wild (1999); Fillipini (1998); and Filippini and Wild (1998).

Brown and Heal (1983) indicates the efficient price for a natural monopoly is the average cost price, where the monopoly makes normal economic profits. Dramani and Tewari (2014) also indicates setting the monopolies price equal to the average cost is more superior than other forms of regulatory price setting mechanism such as price cap regulation. The authors attribute this to its capability to decrease information asymmetry between the regulator and the firm on costs issues.

Most distribution networks are meshed networks making it difficult to allocate their associated costs to specific uses. Burns and Weyman (1996) recommend the use of average costs in pricing such networks. Left on their own monopolies would tend to reduce output and raise price above marginal cost of production to maximise profit (Kirschen and Strabac, 2004). Use of cost of service regulation as is the case in Kenya reduces the challenge of information asymmetry between the regulator and the utility (Filippini and Wild, 1999) and still has the ability to improve welfare by allowing more control over the pricing policy (Laffont and Tirole, 1986). Average costs that exclude energy purchase costs are preferred for distribution companies as they can be used directly for setting network access prices (Filippini and Greene, 2006).

4.1.2 Electricity pricing in Kenya

The electricity subsector in Kenya is a natural monopoly with KPLC being the only supplier of electricity to consumers. The regulator ensures KPLC remains financially solvent while protecting the interests of consumers. The tariff is bundled including all the combined cost of generation, transmission, distribution and retailing. The stages in the electricity tariff design are; demand forecasting which is extensively discussed in chapter two of these study; generation planning of which the efficiency of the contracted generators has been studied on chapter three; determination of the total revenue requirements and unit costs; allocation of the unit costs amongst customers; public hearing of the tariff proposals and final tariff determination and gazettment of the tariff (Electricity regulatory board, 2005).

The regulator sets the tariffs such that there is no subsidy required hence deviating from marginal cost price by setting the prices at average costs (Berg and Tschirhart, 1988). The prices are set such that internal inefficiencies from the monopoly are not passed on to the consumers in the tariffs. One such inefficiency is system losses that arise from power lines, metering and billing errors, theft and corrupt practices. The regulator approves a target level beyond which KPLC absorbs the loss. The regulator attempts to attain the competitive market outcome by accepting the consumer demand for electricity as given and setting reasonable tariffs for producing the output to meet that demand (Electricity regulatory board, 2005). The regulator also subjects the proposed tariffs to public hearing as required by the Constitution of Kenya. The Constitution gives the power of self-governance to the people and public consultations must be conducted for any decision by the state affecting them (Republic of Kenya, 2010). The economic regulation role played by the regulator as well as public participation by consumers' reigns in on the monopoly pricing reducing the welfare loss to the electricity consumers.

The regulator replaces the invisible hand of competition with a visible hand to ensure socially desirable outcomes (Train, 1991)

4.1.3 **Empirical literature**

Studies on pricing of regulated natural monopolies in the transmission and distribution segments of electricity supply have been undertaken using average costs and their application in yardstick regulation. Most of these studies have largely been undertaken in developed countries of Switzerland (Filippini and Wild, 1998, 1999; Filippini, Wild and Kuenzle, 2002; Farsi, Filippini and Greene, 2006); New Zealand (Filippini and Wetzel, 2014, and Nillesen and Pollitt, 2011); Slovenia (Filippini, Hrovatin, and Zorič, 2004). Among the few developing country studies, Dramani and Tewari (2014) estimate average cost as a function of output, price of capital, load factor, price of labour, customer density, voltage and time in Ghana. The study uses panel data from two power distribution companies over the period 1990 to 2010 and finds all the variables except for the price of capital to be significant. This they attribute to capital forming a small proportion of distribution costs as a result of low investments.

Neuberg (1977) estimates the relative cost efficiency and returns to scale of distribution companies in the USA. The study specifies the total distribution cost and average costs to be a function of energy sold, number of customers, number of miles of distribution lines, price of labour, square miles of service territory, price of capital, and ownership. The study finds all the variables to be significant and presence of increasing returns to scale. Municipal firms are more cost efficient than private firms.

Nelson and Primeaux (1988) estimate the total cost function for 23 transmission and distribution utilities in the US. The total cost function is estimated as a function of miles of transmission line, size of the city, total number of customers, output, price of purchased energy, wage rate, technical change and competition environment (duopolistic or monopolistic). The variables are found to be statistically significant in driving total costs.

In a study of England and Wales, Burns and Weyman (1996) estimates the operating costs of 12 distribution companies over the period 1980/81 to 1992/93. The findings show that the number of customers, price of labour, price of capital, total energy delivered, maximum demand, network length, transformer capacity and customer density drive costs. This study informs a lot of the other studies especially on the variables to be included in the estimation of costs. Some of the studies that have borrowed from this study include Filippini and Wild (1999), Filippini et al. (2002), Farsi et al. (2006) and Dramani and Tewari (2014).

Filippini et al. (2002) use a stochastic frontier model to analyze the average cost structure and efficiency of Swiss electricity distribution companies. Using an unbalanced panel data of 59 distribution utilities over 1988- 1996 period, the study finds the main drivers of average cost to be output, price of labour, price of capital, load factor, average consumption per customer and customer density. Other drivers are share of low voltage sales, average consumption low voltage, share of forest land, unproductive land, other outputs and distribution companies operating high voltage lines.

A later study by Farsi, Filippini and Greene (2006) using the same data finds total costs to be determined by output, number of customers, price of capital, price of labour, size of the service area served by the distribution utility, load factor, dummy variable for utilities that operate high-voltage transmission network in addition to their distribution network and dummy variable representing the utilities whose share of auxiliary revenues is more than 25 per cent of total revenues. In earlier works, Filippini and Wild (1999), estimate an average cost function from a panel of 45 Swiss electricity distribution utilities as a basis for yardstick regulation of the distribution network prices. The work considers same variables as in Filippini et al. (2002) with the exclusion of land use. Only the price of labour is found to be insignificant. In a study for Slovenia, Filippini et al. (2004) finds the drivers of cost to be output, price of labour and customer density. The estimates are for five distribution companies for the period 1991 to 2000.

In New Zealand, Filippini and Wetzel, (2014) and Nillesen and Pollitt, (2011) assess the impact of ownership unbundling on electricity prices, quality of service and costs. They compare data before and after the unbundling. Nillesen and Pollitt, (2011) results indicate that although the operational costs decrease with unbundling, the decrease does not result in a decrease in consumer tariffs but in larger profits for the companies. Fillipini and Weltzel (2014) estimates of the impact of ownership unbundling on cost efficiency for 28 distribution companies in New Zealand. The study finds electricity supplied, number of customers, load factor, index of the average interruption duration of the system, consumer density and time dummy to be significant. Ownership unbundling has a positive effect on cost efficiency.

Iimi (2003) uses the production function to assess the impact of unbundling electricity utilities in Vietnam. The study estimates the economies of scale in power generation, transmission and distribution. Using a production frontier, where delivered power is the output while the inputs are expenditure on power received, total transmission lines(capital), personnel expenditure (labour) and number of customers. The study finds significant economies of scale at generation and increasing returns to scale at distribution. The study concludes that vertical disintegration does not necessarily lead to social welfare maximization.

Economies of density and size in electrical power distribution

Roberts (1986) introduces economies of density and size measures that inform a lot of the later studies. The study uses cross sectional data from 65 power utilities in USA to estimate a total cost function. The cost independent variable are prices of inputs, output, squares miles of service area and number of customers. Economies of output density estimates are found to be 1.212, economies of customer density to be 1.014 and the economies of size to be 1.019. The size of the service area is however found to have no significant effect on the cost.

In a study for Saudi Arabia, Al-Mahish (2017) finds existence of economies of output density and economies of customer density of 1.541 and 1.81 respectively. However, the firm is found to be operating at diseconomies of scale of 0.368. The study uses time series data from 1970-2014. The total cost is estimated as a function of output, prices of inputs, transmission network length and number of customers.

Several studies have been undertaken in Switzerland. Fillipini (1998) using data for 39 electricity distribution utilities over the period 1988-1991 finds existence of economies of density and scale. Total cost is assumed to depend on output, inputs prices, load factor, service territory and number of customers. Filippini and Wild (2001;1999;1998) estimate of the average cost function also finds economies of scale. A later study by Filippini et al. (2002) also finds increasing returns to scale, output and customer density. The study estimates an average cost function for 59 distribution utilities. In Filippini and Wild (2001;1999;1998) and Filippini et al. (2002) the average cost function excludes the cost of purchasing electricity to focus on the costs of operating the network system.

Filippini et al. (2004) study for Slovenia finds presence of economies of scale of 2.17. The study assumes the total costs are driven by output, price of inputs (labour and capital), load factor and customer density. Customer density is given by a ratio of number of customers and length of distribution lines in kilometers. Panel data for five distribution utilities over the period 1991-2000 is used for the analysis. The total costs exclude the energy purchase cost. In New Zealand, Fillipini and Weltzel (2014) estimates the total cost function for 28 electricity distribution companies for the period between 1996 and 2011. The study finds economies of scale of 1.035 based on two outputs, quantity of energy and number of customers.

4.1.4 **Overview of reviewed literature and the research gap**

There is paucity of studies on cost of service regulation in the power sector in Africa region compared to other regions in the world. Most of the studies examine the average cost function of the natural monopolies. Costs are unbundled by separating the electricity purchasing costs from the costs of network operation function. This is critical in separating the cost of generating from the costs of delivering the power (network service costs). Electricity supply is viewed as having three products based on the three stages generation, transmission and distribution. The latter two stages, namely transmission and distribution are often combined into one stage and are natural monopolies unlike generation which is open to competition in most of the developed countries.

The studies reviewed show that electricity cost drivers are backed by economic theory. They include output, price of labour and price of capital. They also include specific industry related factors such as voltage level of supply, load factor, number of customers, customer density and time. Other factors considered as drivers of electricity cost include agricultural land share, share of forested land, share of unproductive land, share of an operator’s other activities, number of miles of lines and price of purchased energy. They could also include measures of quality of services such as System average interruption duration index (SAIDI).

Output expansions measure for transmission and distribution companies have been developed and include economies of density and size. The measures assume the companies can increase energy sales, number of customers and the service area. Most of the studies found the presence of economies of scale.

There are no studies that have explained the electricity tariffs in Kenya despite the regulatory reforms that were initiated early 1990s. This study will attempt to fill this research gap by estimating the average costs of the transmission and distribution segment of electricity supply in Kenya that remains a natural monopoly and hence subject to incentive-based regulation.

4.2 Methodology

4.2.1 Theoretical framework

In a competitive market a Pareto efficient output in an industry is realised when output price for a good equals the marginal rate of substitution between the good and all other goods, and consumers are willing to pay its marginal cost (Kirschen and Strbac, 2004). However, in the case of a natural monopoly, producing at the point where price equals marginal cost results in a loss due to the large fixed costs (Kirschen and Strbac, 2004). The marginal costs in a power utility are also very small. A monopoly such as KPLC would require a subsidy or a transfer to remain in operation and to price its output at the marginal cost of production. Shleifer (1985) proposes the use of average cost price where the regulator can only use prices and not lump-sum transfers to compensate the firm. This form of regulation avoids welfare losses from monopoly pricing while permitting high enough prices to the firm's operations.

According to Berg and Tschirhart (1988) a welfare maximizing monopoly producing output q and charging price p faces a welfare and profit function of the following nature

$$\max_{q} W = CS + \pi \qquad 4.1$$

$$CS = \int_0^q p(x)dx - p(q)q \qquad 4.2$$

$$\pi = p(q)q - C(q) \qquad 4.3$$

where W is the welfare, CS is consumer surplus, π is the profits, C is the cost and $p(q)$ is the inverse market demand function.

The first order condition of the welfare maximization problem yields a price that is equal to the marginal cost

$$p(q^w) = C'(q^w) \equiv MC(q^w) \qquad 4.4$$

q^w is the output produced and sold in a competitive market. However, if the monopoly is left to maximize profits, it will maximize equation 4.3 yielding the result that marginal revenue equals marginal cost.

$$MR(q^m) \equiv \; p(q^m) + q^m p'(q^m) = C'(q^m) \equiv MC(q^m) \qquad 4.5$$

q^m is the profit maximizing output of an unregulated monopoly and its less than the efficient market output q^w. There is therefore need for regulation to avoid the welfare loss associated with output q^m. The price charged by the monopoly should be equated to the average cost instead of marginal cost. This results in an output less than the efficient output of q^w but higher than the monopoly output of q^m reducing the welfare loss.

Based on the theory of the firm, Coelli et al. (2005) specifies a general cost model in the form

$$C = C(w, q) \qquad 4.6$$

where C represents cost of the firm, w are the inputs price and q is the output. The average cost

$$AC = \frac{C(\boldsymbol{w},\boldsymbol{q})}{q} \qquad 4.7$$

Dramani and Tewari (2014), Filippini et al. (2002), Filippini and Wild (1998; 1999) specify an average cost model as

$$AC = \frac{C}{Y} = AC(PL, PC, Y, X) \qquad 4.8$$

where AC is the average costs, PL is price of labour, PC is price of capital, Y is output and X represents other exogenous variables as described in Burns and Weyman (1996).

Economies of scale of electrical power distribution

Filippini and Wetzel (2014) using the total cost function with two outputs defines the economies of scale (ES) as

$$ES_{TC} = \frac{1}{\frac{\partial lnTC}{\partial lnY} + \frac{\partial lnTC}{\partial lnCD}} \qquad 4.9$$

where $\frac{\partial lnTC}{\partial lnY}$ is the elasticity of total cost with respect to output and $\frac{\partial lnTC}{\partial lnCD}$ is the elasticity of total cost with respect to customers. Rogers (1982) defines economies of output density (EoD) to be

$$EoD_{YD} = \frac{1}{\frac{\partial lnTC}{\partial lnY}} \qquad 4.10$$

4.2.2 Empirical analysis

Following Dramani and Tewari (2014), average cost of transmission and distribution utility depends on energy sold, price of labour, load factor, price of capital and number of customers or customer density. To avoid multicollinearity problems associated with the average cost being a division of cost and energy sold, we used energy sold relative to the customer density. We expanded Dramani and Tewari (2014) model to include network losses and reforms. System losses in Kenya are critical as KPLC is also a monopoly in retailing function, the inclusion of losses therefore helps us capture inefficiency such as corruption, theft, illegal connections, metering and billing errors. The reforms were included to assess the effect of regulation on the monopoly cost behaviour. Since Kenya has only one distribution company time series data was used for estimation. The general form of the average cost function at period t was

$$AC = f(Y, LF, PK, PL, SL, D_1, D_2,) \qquad 4.11$$

where AC was the average cost, Y was the output (energy sold/customer density), PL was the price of labour, LF was the load factor, PK was the price of capital, SL was the system losses, $D_1$was the dummy variable for 1998 reforms and D_2 the structural break dummy variable from the 2001 occasioned by KPLC return to profit financing strategies and measures aimed at addressing the drought that lasted from 1999 to 2001.

Following Dramani and Tewari (2014), Filippini et al. (2002), Filippini and Wild (1998;1999), equation 4.3 was specified as

$$AC_t = e^{\beta_0} {Y_t}^{\beta_1} e^{\beta_2 \, LF_t} {PK_t}^{\beta_3} {PL_t}^{\beta_4} e^{\beta_5 \, SL_t} e^{\beta_6 D_1} \, e^{\beta_7 D_2} e^{\mu_t} \qquad 4.12$$

where $\beta_0 \ldots . \beta_7$ were the coefficients to be estimated, μ_t was the error term and t was the time period. The other variables were as earlier defined. The log of equation 4.12 gave

$$lnAC_t = \beta_0 + \beta_1 lnY_t + \beta_2 LF_t + \beta_3 lnPK_t + \beta_4 lnPL_t + \beta_5 SL_t + \beta_6 D_1 + \beta_7 D_2 + \mu_t \qquad 4.13$$

where all the variables were as earlier defined.

As discussed in chapter 2, ARDL bounds test approach to cointegration was used to test for the existence of a long-run relationship. This is due to the shortcomings with the Engle–Granger cointegration testing procedure associated with its preference for two variables that must be integrated of the same order (Enders, 2014).The Johansen Cointegration technique could also not be applied due to the study small sample and several variables. The mixture of I (0) and I (1) regressors was also likely to affect the interpretation of the test (Pesaran et al., 2001). Diagnostic stability tests were undertaken for all the identified long-run relationships. This included the LM serial correlation test, normality test, heteroskedasticity test, Cumulative sum of recursive residuals (CUSUM) and CUSUM of Squares Tests.

Following Pesaran, Shin and Smith (2001), equation 4.13 was estimated using ARDL bounds test procedure by modelling it as an error correction model specified as

$$\Delta lnAC_t = \beta_0 + \beta_1 D_1 + \beta_2 D_2 + \delta_1 lnAC_{t-1} + \delta_2 lnY_{t-1} + \delta_3 LF_{t-1} + \delta_4 lnPK_{t-1} + \delta_5 lnPL_{t-1} + \delta_6 SL_{t-1} + \sum_{i=1}^{p} \Delta\theta_i lnAC_{t-i} + \sum_{j=1}^{q} \Delta\varpi_j lnY_{t-j} + \sum_{l=1}^{q} \Delta\varphi_j LF_{t-l} + \sum_{m=1}^{q} \Delta\gamma_m lnPK_{t-m} + \sum_{p=1}^{q} \Delta\eta_p lnPL_{t-p} + \sum_{s=1}^{q} \Delta\alpha_s SL_{t-s} + \mu_t \quad 4.14$$

where β_0 was the constant, $\beta_1 ... \beta_2$ were the coefficients for the dummy variables, δ_1 ... δ_6 were the long run elasticities, $\theta, \varpi, \varphi, \gamma, \eta, \alpha$ were the short run coefficients.

The ARDL model for AC_t was estimated as

$$lnAC_t = \sum_{i=1}^{p} \delta_1 lnAC_{t-i} + \sum_{i=0}^{q_1} \delta_2 lnY_{t-1} + \sum_{i=0}^{q_2} \delta_3 LF_{t-1} + \sum_{i=0}^{q_3} \delta_4 lnPK_{t-1} + \sum_{i=0}^{q_4} \delta_5 lnPL_{t-1} + \sum_{i=0}^{q_5} \delta_6 SL_{t-1} + \mu_t \quad 4.15$$

The error correction model was given by

$$\Delta lnAC_t = \beta_0 + \beta_1 D_1 + \beta_2 D_2 + \sum_{i=1}^{p} \Delta\theta_i lnAC_{t-i} + \sum_{j=1}^{q} \Delta\varpi_j lnY_{t-j} + \sum_{l=1}^{q} \Delta\varphi_j LF_{t-l} + \sum_{m=1}^{q} \Delta\gamma_m lnPK_{t-m} + \sum_{p=1}^{q} \Delta\eta_p lnPL_{t-p} + \sum_{s=1}^{q} \Delta\alpha_s SL_{t-s} + \vartheta_{t-1} + \mu_t \quad 4.16$$

where ϑ was the speed of adjustment. As specified by Pesaran et al. (2001), the dummy variables only appear in this error correction model.

Economies of scale in electricity distribution

According Fillipini and Wild (1999) economies of scale exist if the elasticity of average cost with respect to output is negative, that is if an output expansion results in lower average costs. However, the output Y in equation 4.11 combined the outputs, that is energy sales and customer, in attempt to avoid multicollinearity associated with the average cost being a division of cost and energy sold. To estimate the economies of output density and scale, we estimated the total cost function. All the variables in equation 4.13 were retained apart average costs (AC) which was replaced by total cost (TC), output and customer density were introduced as two separate independent variables. The total cost function of equation 4.13 was restated as

$$lnTC_t = \beta_0 + \beta_1 lnY_t + \beta_2 lnCD_t + \beta_3 LF_t + \beta_4 lnPK_t + \beta_5 lnPL_t + \beta_6 SL_t + \beta_7 D_1 + \beta_8 D_2 + \mu_t \qquad 4.17$$

where TC is the total cost and CD is the customer density. The other variables are as earlier defined.

Following Filippini and Wetzel (2014) and considering KPLC is the only distribution company in Kenya[9] economies of scale were defined as

$$Economies\ of\ scale = \frac{1}{\frac{\partial lnTC}{\partial lnY} + \frac{\partial lnTC}{\partial lnCD}} \qquad 4.18$$

and economies of output density as

$$Economies\ of\ Output\ Density = \frac{1}{\frac{\partial lnTC}{\partial lnY}} \qquad 4.19$$

A value greater than 1 indicates economies of scale and density while a value less than 1 indicates diseconomies of scale and density.

4.2.3 Data type, source and measurement

The study used annual data for 31 years for the period 1985/1986[10] to 2015/2016 sourced from KPLC annual reports. The KPLC annual report provides the annual performance and financial statements to the shareholders.

[9] The geographical size of its service area is the same for the study period since KPLC is the only distributor

[10] KPLC annual report for the period before 1985 did not report on some of the variables considered for the analysis namely operating expenses, number of customers (used in computing the customer density), system load factor, transformer capacity, staff costs and number of staff.

Table 4.3: Description and measurement of variables used to estimate the average costs

Variable	Definition and measurement	Source of Variable
$AC*$	Total operating cost– less energy purchase cost divided by energy sold (Ksh/kWh).	Farsi, et al. (2006) Filippini et al. (2002) Dramani and Tewari (2014)
Y	Electricity sold in (kWh) divided by the customer density. The customer density was calculated by dividing number of customers with the kilometres of line.	
LF	System load factor in percentage	
$PK*$	Operations related capital net book value (Kshs) divided by total transformer capacity (Kva). This gave the price of capital in Ksh/kVA.	
$PL*$	Staff costs (Kshs) divided by number of employees. This gave the price of labour in Ksh/per employee.	
SL	System losses as a percentage of energy generated	Dramani and Tewari (2014)
D_1	Reforms introduced in the sector in 1997/98, 0 was the period 1985/86 to 1996/97 and 1 the period 1997/1998 to 2015/16	
D_2	Strategies structural break, 0 was for the period 1985/86 to 2000/01, 1 for the period 2001/02 to 2015/16	Dummy variable was introduced to correct for structural breaks in the data.

Source: Author

* Adjustment for inflation was done using the electricity CPI index for Kenya base period February 2009 sourced from KNBS

4.3 Empirical results and discussion

4.3.1 Summary statistics

Table 4.4: Summary statistics of variables used in analysing the average costs of KPLC

	Average costs (AC)	Load Factor (LF)	Price of Capital (PK)	Price of Labour (PL)	System Losses (SL)	Output (Y)
Mean	5.614	0.697	4,331.7	1,028,801.9	0.175	146,312,796.6
Std Deviation	3.057	0.017	1,606.5	267,587.3	0.027	21,269,474.5
Maximum	10.193	0.726	6,970.3	1,677,245.3	0.227	203,563,541.8
Minimum	2.165	0.644	2,101.3	487,473.9	0.129	110,812,941.3

Source: Author’s estimates using KPLC annual report data

The summary statistics in Table 4.4 indicate the maximum output per customer density was kWh 203,563,542 reported in 2006/7 a period that was marked with highest economic growth (Republic of Kenya, 2013b). The lowest output per customer density was kWh 110,812,941 reported in 2015/16. This can be attributed to increased customer connections with the highest increase of 35.4% being reported in the period (KPLC, 2018). The increase in the customer connection was mainly in domestic customers who are not heavy consumers of electricity compared to commercial and industrial customer. This reduced the consumption per customer hence reducing the consumption per customer density. The mean output was found to be kWh 146,312,797. The highest price of labour of Kshs 1,677,245 was recorded in 1995/96. This could be attributed to the reforms initiated in the power sector that resulted in the separation of KenGen from KPLC in 1997 (Godinho and Eberhard, 2019). It is in the same period of reform that the highest load factor of 72.6% and lowest price of capital Kshs 6,970 was realized. Highest system losses were recorded in 2002. This could be attributed to the period being affected by several affects including high electricity access costs that may have led to theft and minimal investment in transmission and distribution affecting the network quality (Republic of Kenya, 2004). The lowest real average cost of Kshs 2.165/kWh was reported in 2007/08 a period that was marked with slowed economic growth and post-election violence. Summary statistics of the logged values are presented in Table C.1 in the appendix. Figure C.1 in the appendix presents the graphical presentation of the data used in the analysis. The graphs indicate the possibility of their being structural breaks in the data necessitating breakpoint unit root test.

The correlation matrix in Table C.2 in the appendix indicated low correlations between the variables. Apart from price of labour and capital that had a correlation factor of 0.504, the rest of the variables had correlation factor of below 0.5. This showed collinearity may not be a problem. This was confirmed by the multi-collinearity tests presented in Table C.4 in the appendix.

4.3.2 **Diagnostic tests results**

Unit root test

Table 4.5: Unit root tests for variables used to estimate the average costs of KPLC

Variable	**Test**	**Intercept only**	**Intercept and Trend**	**Results**
Average Cost	ADF	-0.757188	-2.368701	The series are stationary at level at 1% level of significance based on the breakpoint unit root test; Intercept.
	PP	-0.648831	-2.481435	
	KPSS	0.653866	0.095902	
	Breakpoint	-5.787136	-6.257584	
Output	ADF	-1.415374	-0.700004	The series are stationary at level at 5% level of significance based on the breakpoint unit root test; Intercept.
	PP	-1.844218	-1.185262	
	KPSS	0.179960	0.084691	
	Breakpoint	-4.755418	-5.789077	
System losses	ADF	-1.810361	-1.724127	The series are stationary at level at 10% level of significance based on the breakpoint unit root test; Intercept and at 5% for Trend and intercept, trend only.
	PP	-1.823426	-1.765146	
	KPSS	0.267246	0.145169	
	Breakpoint	-4.255751	-4.945066	
Load factor	ADF	-3.784367	-3.71767	The series are stationary at level at 1% level of significance based on the ADF, PP and breakpoint unit root test; Trend and intercept - trend and intercept.
	PP	-3.770010	-3.704217	
	KPSS	0.088748	0.084921	
	Breakpoint	-3.997779	-8.513490	
Price of Capital	ADF	-1.045931	-2.346089	The series are stationary at level at 1% level of significance based on the breakpoint unit root test: Trend and intercept - trend and intercept.
	PP	-1.531329	-1.326560	
	KPSS	0.165692	0.158962	
	Breakpoint	-4.863098	-6.536462	
Price of labour	ADF	-1.6910956	-1.9072234	The series are stationary at level at 1% level of significance based on the breakpoint unit root test: trend and intercept – intercept only
	PP	-1.6910956	-1.9027701	
	KPSS	0.2242067	0.151222	
	Breakpoint	-2.857157	-5.464668	

Source: Author’s estimates from KPLC data.

Critical levels 1%, 5%, and 10% significance levels are as follows; Intercept ADF(-3.67017, 2.963972, - -2.621007), PP(-3.67017, -2.963972, -2.621007), KPSS(0.739000, 0.463000, 0.347000), Break point (-4.949133, -4.443649, -4.193627) Intercept and Trend ADF(-4.296729, -3.568379, -3.218382), PP (-4.296729, -3.568379, -3.218382), KPSS(0.216000, 0.146000, 0.119000) break point; Intercept (-5.347598, -4.859812, -4.607324) Trend and intercept (-5.719131, -5.175710, -4.893950); trend(-5.067425, -4.524826, -4.261048).

As presented in Table 4.5, the variables were found to be stationary at levels. Some of the variables indicated the possibility of having structural breaks, average costs, output, and load factor were found to have breaks in year 2001. This year witnessed financing strategic initiatives aimed at returning KPLC to profitable. The structural breaks could also be associated with the drought period of 1999 to 2001 that affected electricity supply.

Lag length

Table 4.6: Average costs model lag selection results

Model	Akaike information criterion
ARDL (1, 1, 0, 0, 0, 0)	-2.56617
ARDL (1, 1, 0, 0, 1, 0)	-2.51293
ARDL (1, 1, 1, 0, 0, 0)	-2.50172
ARDL (1, 1, 0, 0, 0, 1)	-2.50074
ARDL (1, 1, 0, 1, 0, 0)	-2.49985

Source: Author's estimates from KPLC data.

The model failed the LM serial correlation, CUSUM and CUSUM of squares at lag 2 and lag 3. Table 4.6 indicates the selected model at lag 1. Based on the Akaike information criterion the ARDL model (1, 1, 0, 0, 0, 0) was selected for further analysis.

Residual and Stability test

Table 4.7: Residual and stability diagnostic test results for the average cost model

Description	LM serial correlation	Normality	Heteroskedasticity	CUSUM and CUSUM of squares	Conclusion
No intercept no trend model	0.2274	0.4827	0.6882	within the confines of the 5% significance	Diagnostic tests passed
Intercept and no trend model	0.1932	0.3617	0.4441	within the confines of the 5% significance	Diagnostic tests passed
Intercept with trend model	0.2970	0.3762	0.6107	within the confines of the 5% significance	Diagnostic tests passed

Source: Author's estimates from KPLC data.

All the models at lag 1 passed all the residual and stability diagnostic test as presented in Table 4.7.

Cointegration test

Table 4.8: Bounds test Cointegration results for the average cost model

Description	Critical Values		F statistics	Conclusion
No Constant and No Trend	I(0)	I(1)	18.80759	Long run relationship exists
	1.81(10%)	2.93(10%)		
	2.14(5%)	3.34(5%)		
	2.82(1%)	4.21(1%)		
Intercept and no trend model	I(0)	I(1)	21.81005	Long run relationship exists
	2.26(10%)	3.35(10%)		
	2.62(5%)	3.79(5%)		
	3.41(1%)	4.68(1%)		
Intercept with trend model	I(0)	I(1)	19.87889	Long run relationship exists
	2.75(10%)	3.79(10%)		
	3.12(5%)	4.25(5%)		
	3.93(1%)	5.23(1%)		

Source: Author's estimates from KPLC data.

ARDL bounds cointegration test found the presence of a long run relationship amongst the variables in all the models. The model without trend had a higher F statistic and a higher adjusted R squared, this model was therefore selected for analysis.

4.3.3 Determinants of average cost

Table 4.9: ARDL estimates of Average cost elasticities for KPLC

Variable	**Coefficient**
Short run coefficients	
Constant	5.728* (2.959)
Average Cost (-1)	-0.948*** (0.092)
Load Factor(-1)	-5.083*** (1.120)
Price of Capital	0.037 (0.045)
Price of Labour	0.387*** (0.056)
System Losses	2.170* (1.102)
Output	-0.325** (0.147)
Change in Load Factor	-0.335 (0.979)
Reforms	-0.792*** (0.094)
Structural changes	-0.370*** (0.069)
Error correction term	-0.948*** (0.074)
Long run coeffients	
Load Factor	-5.364*** (1.036)
Price of Capital	0.040 (0.048)
Price of Labour	0.409*** (0.057)
System Losses	2.290** (1.081)
Output	-0.343** (0.154)

Source: Author's estimates from KPLC annual report data

Notes: *** indicates the ceofficient is significant at 1% level; ** indicates the ceofficient is significant at 5% level; * indicates the ceofficient is significant at 10% level. The figures in paranthesis are the standard errors.

The short and long run results are presented in Table 4-8. Most of the variables were found to be significant determinants of average costs and had the expected signs. The coefficients were smaller in the short run compared to the long run, this can be attributed to the short time taken to make adjustments in the short run. The error correction coefficient was negative (-0.948) and significant. This indicated that convergence to equilibrium was fast.

Price of labour and system loss had the effect of increasing average cost in the short run while output, lagged load factor, lagged average costs, reforms and structural changes were likely to decrease average costs. The significance and signs of the short run coefficients were maintained into the long run. An increase in price of labour and system losses was likely to cause an increase in the average cost of electricity. Increasing price of labour by 1% was likely to lead to an increase in the average cost of 0.39% in the short run and 0.41% in the long run. System losses were found to have a higher magnitude with a 1% increase in system losses causing an increase in the average cost of 2.17% in the short run and 2.29% in the long run.

An increase in the load factor and outputs was likely to decrease the average cost of electricity. In the short run increasing output by 1% was found likely to decrease the average cost by 0.32% in the short run, while in the long run a 1% increase in the output reduced the average cost by 0.34%. This finding is consistent with economic theory and indicates that KPLC is enjoying economies of scale. Similarly, and in the short run increasing system load factor by 1% was likely to decrease the average costs by 5.08% in the next period. In the long run a 1% increase in system load factor would reduce the average costs by 5.36%. The study also found that increasing average costs by 1% in the previous period was likely to see the company reduce the average costs by 0.95% in the short run. The two sets of reforms had the effect of reducing average costs. Sector reforms of 1998 reduced average costs of electricity distribution in Kenya by 0.79%. The second set of structural reforms of 2001 reduced average costs by 0.37%. The 1998 reforms established the sector regulator, and this could have contributed to the reduction in average costs.

These findings were comparable to those of other empirical studies undertaken in Africa and other regions. For example, Dramani and Tewari (2014) study for Ghana also finds the drivers of average costs to be output, load factor and price of labour. The price of labour elasticity in their study is 0.31 making it very close to the finding of this study. They attribute the significance of price of labour in driving average costs to the fact that distribution systems require more labour for meter reading, billing and distribution network trace clearance. In addition to this, in Kenya, the ageing distribution network also means deploying more labour for maintenance of the network which is prone to outage. Filippini and Wild (1999) and Filippini et al. (2002) study for Switzerland also finds output and load factor to be significant drivers of average costs.

The studies undertaken in Switzerland find load factor to play a significant role in driving down the average costs of electricity. Filippini and Wild (1999) find the response of average cost to the load factor to be higher than that estimated in this study at -11.23. The finding of a later study by Filippini et al. (2002) also find a high load factor coefficient of -7.8. Dramani and Tewari (2014) and Filippini and Wild (1999) opine that time of use tariffs could help increase the load factor, hence reducing the average costs.

None of the studies reviewed considered system losses and sectoral reforms. This study found the reforms of 1998 that allowed for the regulation of the monopoly contributed to reducing of the average cost. This finding is consistent with the theory of regulation that the regulator allows more control over the pricing policy improving welfare and ensuring socially desirable outcomes. The second reforms of 2001 that saw further unbundling of the sector and accelerated customer connection also contributed in driving down the average costs. This indicates that the reforms agenda that push for effective operation of the utilities in the sector are bearing fruit. Network system losses were found to be increasing average costs. This finding is intuitive as system losses contribute to the operational expenses of a company. System losses is energy purchased that should have been sold but was lost in the system and captures losses arising from the power lines, theft, corruption, metering and billing errors all of which have been issues affecting KPLC in the recent past.

Economies of scale and power output density.

Table 4.10: Economies of scale and output density estimates

Variable	**Coefficient**
Elasticities	
Output	0.571** (0.225)
Load Factor	-4.636** (1.738)
Price of Capital	0.031 (0.050)
Price of Labour	0.369*** (0.084)
System Losses	2.178* (1.063)
Customer Density	0.364** (0.157)
C	7.967 (4.681)
Economies of Scale and Density	
Economies of output density	1.750
Economies of Scale	1.069

Source: Author’s estimates from KPLC annual report data

Notes: *** indicates the ceofficient is significant at 1% level; ** indicates the ceofficient is significant at 5% level; * indicates the ceofficient is significant at 10% level. The figures in paranthesis are the standard errors.

Table 4.10 presents the long-run elasticities of the total cost function[11]. The results indicate output, load factor, price of labour, system losses and customer density to be significant determinants of the total costs for KPLC. All the coefficients have the expected sign and are consistent with the average cost function estimates. The output and customer density elasticity are positive implying an increase in production of output will increase total cost.

Economies of scale and density calculated using equation 4.18 and 4.19 were found to be greater than 1. The economies of output density were found to be 1.75. This indicates that KPLC is characterised by economies of output density. Economies of output density indicate decreasing average costs as the volume of electricity sold to a fixed number of customers increases (Filippini, 1998). This is confirmed by the elasticity of average cost with respect to output which was found to be negative at -0.343079, meaning that increasing output with 1% was likely to decrease average cost by 0.34%. This was also supported by the decreasing average cost curve with output in Figure 4.2. The economies of scale were found to be 1.069, indicating the average costs of KPLC decrease when output and customers' density increase.

The indicators of economies of output density and scale shows that KPLC is still able to meet the country's demand and distribute electricity at a lower cost than having several firms. Competition would be less cost efficient than a monopoly in the distribution of electric power. The result indicates the need to retain the transmission and distribution segment of electricity supply as a natural monopoly as competition could lead to excess capacity.

This finding is consistent with the theories of regulation that indicate that economies of scale and a decreasing average cost curve indicate the presence of a natural monopoly in

[11] The diagnostic tests are provided in the annex Tables C.16 to C.19

a market (see Stigler, 1971; Shleifer, 1985; Berg and Tschirhart, 1988; Train, 1991; Kahn,1998; Posner, 1999; Laffont, 2005; Joskow, 2005; and Public utility research center, 2012). This result corroborates the findings of Filippini and Wild (1999), Filippini et al. (2002), Dramani and Tewari (2014) and Filippini and Wetzel (2014).

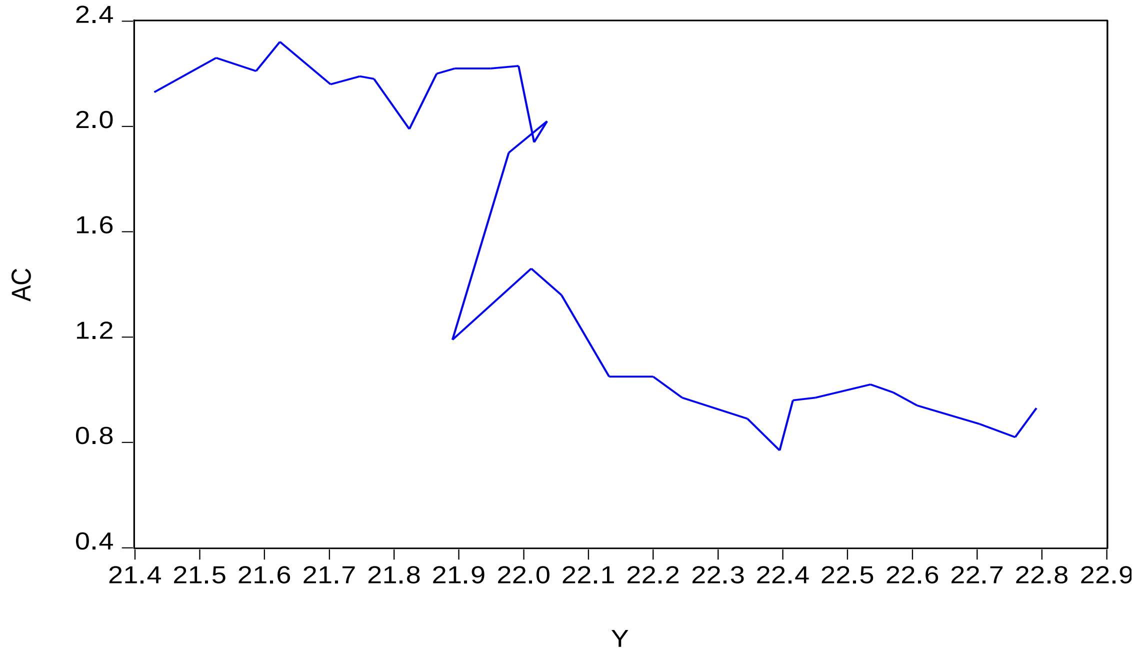

Figure 4.2: KPLC Average cost curve (1985/1986 - 2015/16)

Source: Author’s compilation from KPLC annual reports data

4.4 Summary and conclusion

The essay sought to identify the drivers of electricity cost in Kenya using annual data from KPLC for the period 1985/1986 to 2015/16. Applying an ARDL model, output, price of labour, price of capital, system losses, load factor, 1998 reforms and the 2001 structural break dummy variable were considered as the independent variables in estimating the average cost function.

In the short run average costs responded to the lagged average cost, lagged load factor, price of labour, system losses, output, 1998 reform and 2001 structural break. Apart from price of labour and system losses the other variables reduced the average cost in the short run. The drivers of the long run[12] average costs were found to be output, load factor, system losses and price of labour. Price of labour and system losses increased the average cost. The elasticity of average costs with respect to output was negative. This indicated the presence of economies of scale. The presence of economies of scale was also confirmed by a declining average cost curve with output.

4.5 Policy recommendations

The regulator should consider applying this model as one of its pricing rules. The regulator can do this by using the model to estimate the average costs of KPLC and comparing with the actual costs incurred as a way of checking KPLC's efficiency before making pricing regulatory determination. This would reduce information asymmetry between the regulatory and the utility. The regulatory can also consider engaging other regulators in Africa that are regulating utilities of a similar size and function for yardstick regulation. This would facilitate efficiency competition amongst the utilities participating in the benchmarking.

System losses were found to be increasing average cost of electricity. There is need for KPLC to set up measures geared towards reducing the system losses. The regulator should also be strict in setting the loss targets for KPLC. This will protect consumers from paying high costs resulting from losses associated with theft, corruption, metering and billing errors. The loss targets should be coupled with the necessary investments in the distribution network to reduce non-commercial losses associated with a weak network. The regulator should also set efficiency targets aimed at ensuring the management of KPLC continues to reduce average costs by lowering the cost of labour. This can be done by tying staff costs to certain performance standards such as improved quality of supply and customers supplied.

[12] In the long-run only the cointegrating or equilibrating equation is maintained as the short-run dynamics disappear.

The finding on the system load factor indicated the need for the government to put up measures that are likely to increase the load factor. High load factor can be achieved by distributing the load through time of use tariffs and increased consumption of energy. The Ministry of Energy and the regulator should therefore continue implementing the time of use tariffs and monitor its effectiveness in increasing the load factor (reducing the peak demand). Implementation of measures that encourage the establishment of energy intensive industry, 24-hour economy and economic advancements such as special economic zones and industrial parks is also likely to increase consumption of energy hence increasing the load factor. The Ministry of Energy can support these initiatives by providing attractive electricity tariffs as well as stable supply of power.

Reforms were found to reduce the average costs. The Ministry of Energy should not shy away from implementing the proposed reforms in the Energy Act of 2019. The proposed reforms include the establishing of an independent system operator to facilitate open access to the distribution and transmission networks to customers and enhance regional trade. The Ministry of Energy should also consider implementing the reforms that encourage competition in the generation segment of electricity supply. The current protection offered to generators could be encouraging the inefficiencies identified in chapter 3 of this thesis.

The finding on existence of economies of scale indicates the need to retain transmission and distribution as regulated natural monopolies. The regulator can take advantage of regional association to introduce yardstick regulation using similar firms in the region as benchmarks to improve the cost efficiency of the utilities. The regulator can also reduce information asymmetry associated with costs of service regulatory through constant monitoring of the utility cost data.

4.6 **Contribution of the study**

This study is important as it estimates the drivers of average electricity costs and fills a gap that has not been addressed in Kenya before. The study also provides a model that can be used by the regulator to predict the cost levels for KPLC in place of the costs incurred and reduce information asymmetries. Further, the study explores the scale economies of KPLC as well as the effects of reforms introduced in the sector on the cost of supply of electricity. Previous study reviewed did not include system losses in their analysis. This study contributes to literature by estimating the effects of system losses on the average cost of electricity.

4.7 Limitation of the study

The study lacked data on the system security or quality of supply indices such as system average interruption duration index or system average interruption frequency index. These are important operating characteristic as proposed by Burns and Weyman (1996), an estimation on their effect on the average costs would have contributed to the findings of this paper. Lack of an electricity price realised from a competitive market limited the estimation of consumer welfare loss arising from regulated monopoly pricing

4.8 Areas for further research

The study used time series data from KPLC as that was the only available data. However, with the ongoing regional integration in the region this study can be extended to a relative efficiency analysis of KPLC and other similar companies in the region as the benchmarks. Efficiency analysis will also be possible in the transmission segment once KETRACO is fully established and KPLC separates its transmission costs from those of distribution which is currently not the case. This will allow the regulator to use yardstick regulation in determining network prices. Due to lack of data the study used system losses as a proxy for all inefficiencies and losses including corruption, it would be important to also understand the role of corruption in driving the costs of electricity.

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CHAPTER 5

SUMMARY, CONCLUSION AND POLICY RECOMMENDATIONS

5.0 Summary and conclusions

This study investigates three key issues identified as critical in the realisation of affordable electrical power energy in Kenya. The three issues include realistic demand forecasting, efficient production of energy and KPLC tariffs push factors. These issues informed the study objectives which were to forecast electricity demand; assess the technical efficiency of thermal electricity generating firms and explain electricity tariffs in Kenya. The first chapter provided background information to the electricity subsector in Kenya and laid the basis for the three essays.

The first objective of the study sought to forecast electricity demand, compare it with the official government forecast as well as identify the determinants of demand. Three models were estimated; aggregated demand for electricity; household electricity demand and commercial and industrial electricity demand. The estimated models were used to forecast electricity demand up to the year 2035. To mirror the government forecast three scenarios were considered; low or pessimistic; medium or reference; and the high or optimistic. The aggregate demand forecast was compared with the official government forecast. Household, commercial and industrial forecasts were developed to assess their contribution to the demand forecast in the future.

The results found the determinants of aggregate demand in the short run to be lagged electricity demand, lagged hydro inflows, GDP, lagged diesel prices, connections and reforms. The determinants in the long run were found to be hydro inflows, GDP and diesel price. Drivers of residential electricity demand in the short run included: lagged electricity demand, lagged GDP, lagged urbanization rate, lagged hydro inflows, change in demand one and two years back, lagged change in GDP, lagged change in urbanization rate, change in hydro inflows, lagged change in hydro inflows and connections. In the long run the drivers were GDP, hydro inflows and urbanization rate. In the short run electricity demand for commercial and industrial sector was found to be driven by lagged electricity demand, lagged energy efficiency, lagged output, hydro inflows, lagged price of electricity, lagged change in the demand, changes in efficiency, lagged change in efficiency, change in output, lagged change in output and reforms. In the long run the drivers were efficiency, output, hydro inflows and price of electricity.

Aggregate electricity demand was found to be income inelastic, household electricity demand was price elastic. Commercial and industrial electricity demand was found to be income elastic and price inelastic. Supply side challenges such as hydro inflows were found to have the potential of constraining electricity demand, creating suppressed or unmet demand in the subsector. Energy demand was projected to rise by an average growth rate of 5.7%. The projection was lower than the official forecast an indication that the official forecast could be overstated. Commercial and industrial electricity demand was projected to continue contributing the most to the electricity demand followed by household electricity demand as is the case currently.

The second objective attempted to establish the efficiency of thermal electricity generating plants in Kenya. Stochastic Frontier Analysis (SFA) was used to estimate unbalanced panel data from 27 thermal power plants over the period July 2015 to December 2017. Two other separate SFA estimates were undertaken for the 8 grid connected plants and 19 isolated plants. Data Envelope Analysis (DEA) Malmquist index was used to estimate the efficiency changes in the period of analysis.

The results found fuel to be a positive determinant in the generation of energy for all the power plants. Estimates for the grid connected plants found capital to also determine the production of electricity. The plants were found to be having increasing returns to scale. None of the power plants was efficient. The average efficiency score for all the thermal power plants was found to be 71.06%. Grid connected power plants were found to be more efficient when estimated separately from isolated plants. The mean efficiency for the grid connected plants was 98.78% while that for isolated plants was 82.73%. The determinants of efficiency were identified as age, connection to the grid and ownership. Age and public ownership affected efficiency negatively, connection to the grid had a positive effect. The Malmquist productivity index indicated efficiency and productivity improvement.

The third objective sought to explore the drivers of electricity cost in Kenya using annual data from KPLC for the period 1985/1986 to 2015/16 and ARDL model. The scale of operation of KPLC was also assessed as well as the effects of reforms on the tariffs.

Empirical results found short run average cost to be determined by lagged average cost, lagged load factor, price of labour, system losses, output, 1998 and 2001 reforms. In the long run average costs were found to be driven by output, load factor, system losses and price of labour. Price of labour and system losses were found to be increasing the average cost in the short run and long run. The elasticity of average costs with respect to output was negative indicating the presence of economies of scale. The system load factor and reforms were also found to have the effect of reducing the average costs. The study also found the existence of economies of output density and economies of scale.

5.1 **Policy recommendations**

The study findings indicate the official demand forecast could be overstated. There is need for the Ministry of Energy to consider supplementing the engineering method currently being used for forecasting the official demand with the one proposed in this study. This is to allow for a comparison between the engineering method demand forecast with the economic study based demand forecast. The Ministry of Energy may also consider revisiting previous investment plans to ensure there is no demand supply imbalance. KPLC should consider signing take and pay power purchase agreement instead of take or payment. This will avoid the payment of excess capacity that increase electricity tariffs.

Supply side constraints were found to play a significant role in driving electricity demand. This also indicated the possibility of unmet demand that could be suppressing the recorded demand. There is need for continued interventions by Ministry of Energy and its associated agencies to address the constraints such as dependency on hydro generated electricity that causes power rationing during drought, outages and lack of access to electricity. Some of the interventions and measures the Ministry of Energy could consider include: diversifying the source of electrical energy to avoid dependency on hydro electricity generated energy, continuing with customer connections to allow access to electricity and grid strengthening to reduce on the outages for the already connected customers.

Commercial and industrial consumers were found to be the leading contributors to electricity demand in the future as is the case currently. There is therefore need for the Ministry of Energy to address not only the supply side constraints but the price of electricity. Commercial and industrial electricity demand was found to be negatively affected by price of electricity. The tariff measures the government can use to incentives commercial and industrial consumers demand include; continuing with the time of use tariffs, introducing special tariffs for industrial parks and electricity tax rebate programs.

The study found all the thermal generating power plants to be inefficient. Ministry of Energy should consider removing the current protection provided to the contracted generators in the form of take or pay power purchase agreements and replace with take and pay contracts. This should be coupled with clear steps towards establishing a competitive market in generation as envisaged in the Energy Act, 2019. Factors identified to be affecting efficiency negatively included public ownership and age of the plants. The Ministry of Energy should therefore continue with the reform agenda and encourage private investment in generation. There is also need for the Ministry of Energy, KPLC and KenGen to retire power plants when they reach their economic life. Grid connection was found to have a positive effect on efficiency, the Ministry of Energy and KPLC should work towards connecting most of the isolated stations to the grid.

The power plants were found to be operating on increasing returns to scale, indicating with the same inputs currently being deployed more output could be achieved. The regulator should therefore consider using the findings of these paper to implement incentive regulation measures. The study also found fuel to be playing a critical role in the generation of energy. There is need for the regulator to relook at the monthly fuel cost pass through to consumers that may not be incentivising the generators to be more efficient. The regulator could revise the specific fuel targets downwards using a relative thermal efficiency measure.

The study found system losses and price of labour were contributing to the increase in the average cost of KPLC. The regulator should set strict loss reduction targets for KPLC as well as efficiency measures aimed at reducing the cost of labour. The regulator and the Ministry of Energy should at the same time facilitate KPLC with the requisite resources required to upgrade the distribution system. A strong distribution system could reduce the system losses as well the cost of labour. The regulator could also reduce the price of labour by tying increase in staff costs to certain performance standards such as improved quality of supply and number of customers supplied. This is possible as the regulator approves any increase in KPLC costs during the review of the retail tariffs. The Ministry of Energy should also implement the proposed reforms in the Energy Act, 2019, the reforms proposed introducing competition in the commercial functions of KPLC. This is likely to reduce the commercial losses associated with theft, corruption, billing and metering errors at KPLC.

System load factor was found to play a critical role in reducing KPLCs average costs. Increase in the load factor can be achieved by distributing the system load through time of use tariffs and increased energy consumption throughout the day. The Ministry of Energy and the regulator should therefore continue implementing the time of use tariffs and monitor its effectiveness in increasing the load factor (reducing the peak demand). Further the government should continue with the implementation of measures that encourage the establishment of energy intensive industries, 24-hour economy and economic advancements such as special economic zones and industrial parks. This will also contribute in growing commercial and industrial consumers' electricity demand.

Reforms were found to reduce the average costs. Ministry of Energy should therefore embark on implementing the proposed reforms in the Energy Act of 2019. The proposed reforms include; developing an electricity market in generation, allowing open access to the distribution and transmission network to facilitate trade, allowing competition in the commercial functions and separating selling and buying of power from system operation.

The finding on existence of economies of scale in KPLC indicates the need for the Ministry of Energy to retain distribution as a regulated natural monopoly. Introducing a competitor would make the energy sector stop enjoying the economies of scale. To improve on consumer welfare, the regulator should use the finding of this study to improve on the cost observability of KPLC. The regulator should also consider subjecting KPLC to yardstick regulation with similar firms in the region as benchmarks to improve on its cost efficiency.

5.2 **Contribution to knowledge**

The study makes an important contribution to literature by estimating the role supply side constraints play in electricity demand. Previous studies reviewed had not considered the role of supply side constraints. Supply side constraints such as lack of electricity access, power outages and rationing for those already connected to the grid are likely to contribute to unmet demand. By using hydro inflows as a proxy for supply side constraints, the study found such constraints play a significant role in the determination of electricity demand. The study also contributes to policy by comparing the official demand forecast with the one undertaken in this study. The findings indicate the official forecast could be overstated and may need to be supplemented with the one from this study.

The study fills a research gap on operational efficiency of electricity generating plants in Kenya. Although efficiency analysis of power generating plants has been undertaken in other countries, there is none that has been done for Kenya. This study therefore contributes to knowledge on the efficiency levels of the thermal power generating companies in Kenya. Further the finding of these study contributes to policy on interventions that the regulator can use in making future decisions and in the designing of regulatory incentives and an electricity market.

The study also addresses another research gap on the drivers of KPLC tariffs. Information on the key drivers of electricity costs in Kenya is of interest to consumers of electricity and the government. The model used in this study can be replicated by the regulator in predicting the cost levels for KPLC in place of the actual costs incurred hence reducing information asymmetries This study also contributed to literature by estimating the effects of system losses on the average cost of electricity. Previous studies reviewed in literature did not consider system losses in their analysis.

5.3 Limitations of the study

There was paucity of data that affected this study in a few ways. First, the lack of historical data at county level meant the demand forecast could not be disaggregated to the county level. Second, most of the private investments after the reforms of 1997 were done in thermal power plants, limiting our study to thermal power plants. The length of the data available was also limiting for a good measure of efficiency and productivity change. Third, the lack of data on system security or quality of supply meant the operating characteristics of KPLC were not included in the average cost estimates as proposed by Burns and Weyman (1996). The presence of only one distribution company also meant efficiency analysis could not be undertaken. Further the lack of an electricity market limited the estimation of consumer welfare loss associated with monopoly pricing.

5.4 Areas of further research

The demand forecasting methodology proposed in this study can be applied in forecasting demand in the counties once the sector and country statistics are reported based on the counties. Such a study will ease energy planning and reticulation at the devolved function levels. To produce a comprehensive investigation of efficiency of generating power plants, future studies could estimate the efficiency of other technologies such as geothermal, hydro, wind and solar. Efficiency studies could in the future be extended to the transmission and distribution segment also and be utilised in yardstick regulation. Although the study analysed the effect of system losses on average costs, it would be important to also understand the role of corruption in driving the costs of electricity.

APPENDICES

A. Appendix 1: Electricity demand forecast in Kenya

Aggregate demand for electricity in Kenya

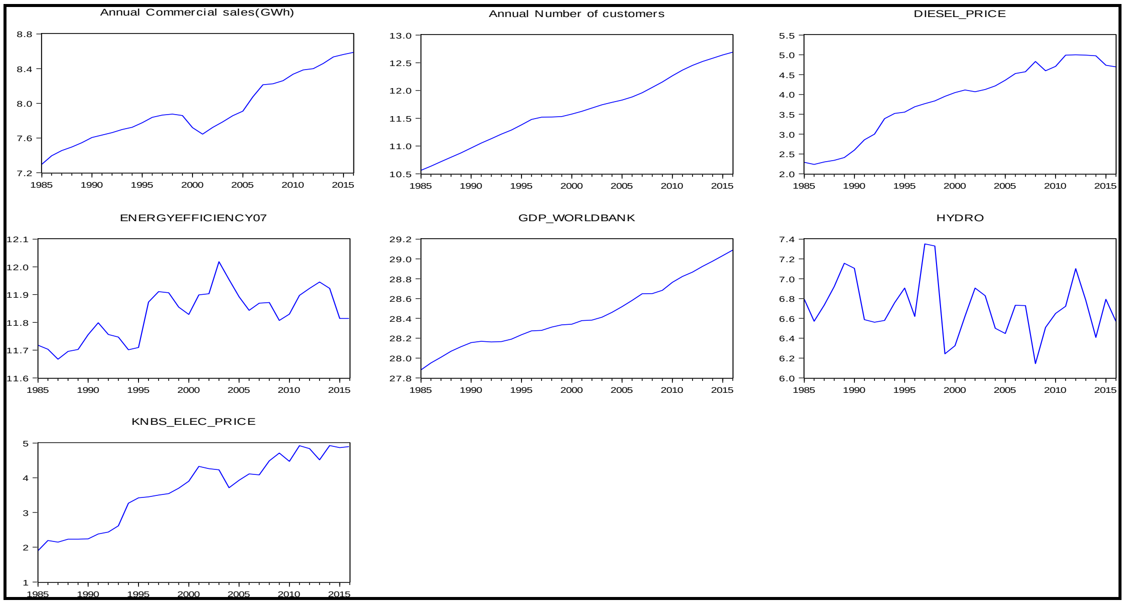

Figure A.1: Graphical presentation of the variables used to estimate the aggregate demand for electricity

Source: Author's compilation from KPLC, KNBS, World Bank and KenGen data.

Table A.1: Aggregate electricity demand data summary statistics after logarithmic transformation

Log of Variable	**Mean**	**Std. deviation**	**Min**	**Max**
GDP	28.432	0.331	27.882	29.090
Hydro inflows	6.718	0.284	6.144	7.352
Energy efficiency	11.829	0.091	11.667	12.018
Number of customers	13.425	0.917	12.233	15.527
Electricity sales	8.243	0.378	7.573	8.929
Price of electricity	3.639	0.992	1.901	4.929
Diesel Price	3.854	0.918	2.238	4.999

Source: Author's computation from KPLC, KNBS, World Bank and KenGen data.

Table A.2: Correlation Matrix of the variables used to estimate the aggregate electricity demand

Variable	Electricity sales	Hydro	Number of Customers	Diesel price	Price of electricity	Energy efficiency	GDP
Electricity sales	1.000	-0.188	0.981	0.936	0.923	0.603	0.993
Hydro	-0.188	1.000	-0.198	-0.255	-0.219	-0.051	-0.191
Number of Customers	0.981	-0.198	1.000	0.885	0.899	0.540	0.992
Diesel price	0.936	-0.255	0.885	1.000	0.970	0.741	0.913
Price of electricity	0.923	-0.219	0.899	0.970	1.000	0.711	0.913
Energy efficiency	0.603	-0.051	0.540	0.741	0.711	1.000	0.578
GDP	0.993	-0.191	0.992	0.913	0.913	0.578	1.000

Source: Author's computation from KPLC, KNBS, World Bank and KenGen data.

Table A.3: Coefficient Variance Decomposition for the aggregate electricity demand variables

Eigenvalues	1.538	0.001	0.000	0.000	0.000
Condition	0.000	0.000	0.000	0.002	1.000
Variance Decomposition Proportions					
	Associated Eigenvalue				
Variable	1	2	3	4	5
Hydro	0.002	0.064	0.933	0.001	0.000
GDP	0.984	0.002	0.014	0.000	0.000
Price of electricity	0.082	0.875	0.026	0.017	0.000
Diesel price	0.062	0.925	0.001	0.012	0.000
Constant	1.000	0.000	0.000	0.000	0.000

Source: Author's computation from KPLC, KNBS, World Bank and KenGen data.

The condition numbers are smaller than 0.001 for three of the five eigenvalues indicating the possibility of dependency between the variables. However, the first column which shows the proportions associated with the smallest condition number has only one number that is a larger than 0.5 (Hill and Adkins, 2001). This indicates low collinearity between the variables.

Household demand for electricity

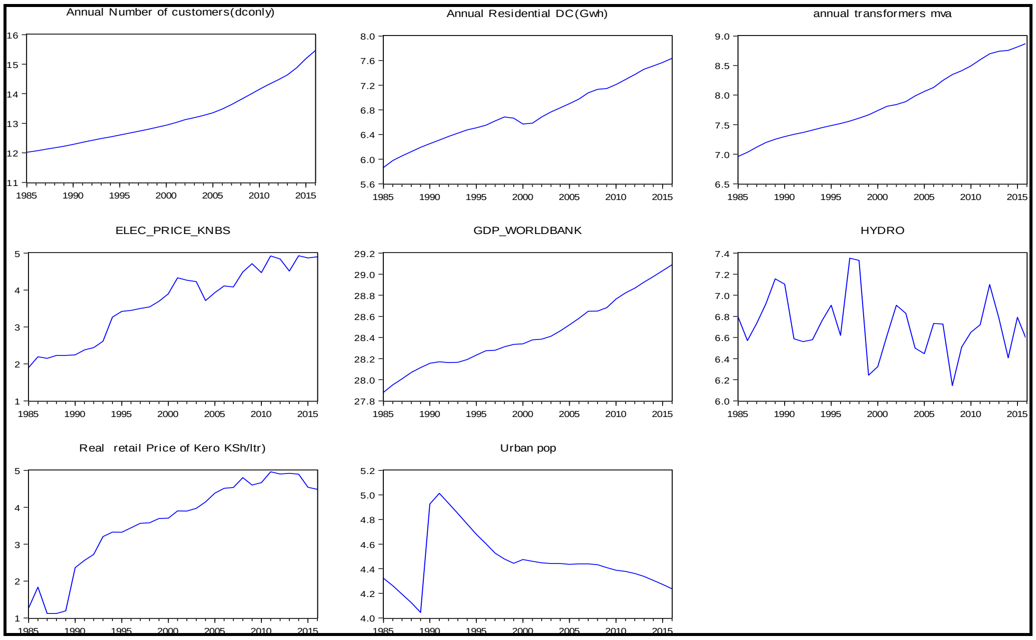

Figure A.2: Graphical presentation of the variables used to estimate household electricity demand

Source: Author's compilation from KPLC, KNBS, World Bank and KenGen data.

Table A.4: Households electricity demand data summary statistics after the logarithmic transformation

Log of Variable	**Mean**	**Std. deviation**	**Min**	**Max**
GDP	28.702	0.135	28.599	29.090
Hydro	6.718	0.284	6.144	7.352
Electricity consumed by households	6.744	0.491	5.865	7.637
Number of Domestic consumers	13.225	0.970	12.018	15.459
Distribution transformers	7.866	0.582	6.962	8.879
Price of Kerosene	3.566	1.212	1.120	4.959
Price of Electricity	3.639	0.992	1.901	4.929
Urbanization rate	4.464	0.229	4.044	5.013

Source: Author's compilation from KPLC, KNBS, World Bank and KenGen data.

Table A.5: Correlation matrix for the variables used in the estimation of household electricity demand

	Household electricity sales	No. of customers	Distribution transformers	Price of Electricity	GDP	Kerosene Price	Urbanization rate	Hydro
Household electricity sales	1.000	0.976	0.990	0.930	0.992	0.908	-0.228	-0.188
No. of customers	0.976	1.000	0.984	0.892	0.990	0.827	-0.323	-0.200
Distribution transformers	0.990	0.984	1.000	0.930	0.995	0.890	-0.286	-0.216
Price of Electricity	0.930	0.892	0.930	1.000	0.913	0.939	-0.248	-0.219
GDP	0.992	0.990	0.995	0.913	1.000	0.869	-0.276	-0.191
Kerosene Price	0.908	0.827	0.890	0.939	0.869	1.000	0.008	-0.274
Urbanization rate	-0.228	-0.323	-0.286	-0.248	-0.276	0.008	1.000	-0.051
Hydro inflows	-0.188	-0.200	-0.216	-0.219	-0.191	-0.274	-0.051	1.000

Source: Author’s computation from KPLC, KNBS, World Bank and KenGen data.

Table A.6: Coefficient Variance Decomposition for the Household electricity demand estimation

Eigenvalues	6.7	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Condition	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
Variance Decomposition Proportions																	
	Associated Eigenvalue																
Variable	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Household electricity sales (-1)	0.0	0.5	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Household electricity sales (-2)	0.2	0.5	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Price of Electricity	0.1	0.0	0.1	0.0	0.0	0.0	0.6	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Price of Electricity(-1)	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.6	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Price of Electricity(-2)	0.0	0.0	0.1	0.0	0.3	0.1	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Price of Electricity(-3)	0.0	0.0	0.0	0.1	0.7	0.0	0.0	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GDP	0.3	0.5	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GDP(-1)	0.2	0.7	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GDP(-2)	0.2	0.1	0.4	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro inflows	0.0	0.1	0.0	0.1	0.6	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0
Hydro inflows(-1)	0.0	0.3	0.3	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0
Hydro inflows(-2)	0.2	0.0	0.1	0.1	0.2	0.0	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Urbanization rate	0.0	0.1	0.1	0.0	0.0	0.6	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Urbanization rate(-1)	0.2	0.0	0.0	0.2	0.1	0.4	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Connections	0.1	0.4	0.3	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reform	0.1	0.0	0.1	0.1	0.5	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0
C	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Source: Author's computation from KPLC, KNBS, World Bank and KenGen data.

The decomposition proportions associated with the smallest condition number are located in the first column and indicate that none of the variables is larger than 0.5 indicating weak dependencies between the variables that cannot affect the estimation.

Commercial and industrial demand for electricity in Kenya

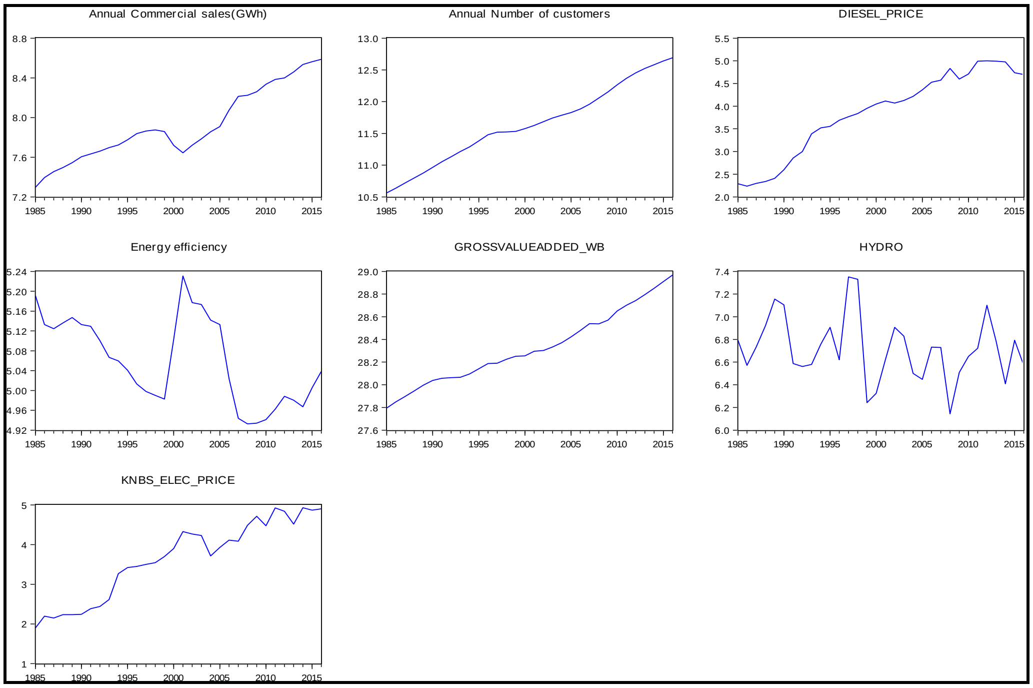

Figure A.3: Graphical presentation of the variables used in estimating the commercial and industrial electricity demand

Source: Author's compilation from KPLC, KNBS, World Bank and KenGen data.

Table A.7: Commercial and industrial electricity demand data summary statistics after logarithmic transformation

Log of variable	**Mean**	**Std. deviation**	**Min**	**Max**
Income	28.329	0.323	27.795	28.968
Hydro inflows	6.718	0.284	6.144	7.352
Commercial and industrial Electricity consumption	7.918	0.369	7.297	8.587
Number of customers	11.641	0.618	10.564	12.691
Diesel price	3.854	0.918	2.238	4.999
Energy efficiency	5.060	0.087	4.933	5.231
Price of Electricity	3.639	0.992	1.901	4.929

Source: Author's computation from KPLC, KNBS, World Bank and KenGen data.

Table A.8: Correlation matrix for the variables used in the estimation of commercial and industrial electricity demand

	Commercial and industrial Electricity consumption	Number of customers	Diesel price	Energy Efficiency	Income	Hydro inflows	Price of Electricity
Commercial and industrial Electricity consumption	1.000	0.966	0.894	-0.759	0.975	-0.160	0.874
Number of customers	0.966	1.000	0.961	-0.631	0.991	-0.195	0.956
Diesel price	0.894	0.961	1.000	-0.632	0.925	-0.255	0.970
Energy Efficiency	-0.759	-0.631	-0.632	1.000	-0.615	0.111	-0.558
Income	0.975	0.991	0.925	-0.615	1.000	-0.197	0.926
Hydro inflows	-0.160	-0.195	-0.255	0.111	-0.197	1.000	-0.219
Price of Electricity	0.874	0.956	0.970	-0.558	0.926	-0.219	1.000

Source: Author’s estimates from KPLC, KNBS, World Bank and KenGen data.

Table A.9: Coefficient Variance Decomposition for the commercial and industrial electricity demand estimation

Eigenvalues	4.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Condition	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
Variance Decomposition Proportions													
	Associated Eigenvalue												
Variable	1	2	3	4	5	6	7	8	9	10	11	12	13
Commercial and industrial Electricity consumption(-1)	0.4	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial and industrial Electricity consumption(-2)	0.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Energy Efficiency	0.1	0.0	0.0	0.2	0.5	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Energy Efficiency (-1)	0.4	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Energy Efficiency (-2)	0.0	0.9	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Output	0.0	0.0	0.7	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Output (-1)	0.1	0.6	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Output (-2)	0.2	0.8	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro inflows	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.2	0.1	0.0	0.4	0.0	0.0
Price of Electricity	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.3	0.0	0.0	0.0	0.0
Price of Electricity(-1)	0.2	0.0	0.0	0.0	0.0	0.1	0.0	0.6	0.0	0.0	0.0	0.0	0.0
Reforms	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3	0.1	0.0	0.0	0.0
Constant	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Source: Author's computation from KPLC, KNBS, World Bank and KenGen data.

The decomposition proportions associated with the smallest condition number are located in the first column and indicate that none of the variables is larger than 0.5 indicating weak dependencies between the variables that cannot affect the estimation.

B. **Appendix 2: Technical efficiency of thermal electricity generators in Kenya**

Table B.10: Summary statistics of generating plants after the logarithmic transformation

Log of Variable	Mean	Std. Deviation	Minimum	Maximum
Combined Grid connected and power plants - Total number of observations 742				
$Output$	5.927	2.729	1.118	11.102
$Capital$	1.217	2.321	-1.022	4.787
$Labour$	2.443	1.161	1.386	4.585
$Fuel$	11.762	2.387	8.089	16.473
age	7.5	5.8	1	27
$grid$			0	1
$ownership$			0	1
Grid connected power plants - Total number of observations 234				
$Output$	9.285	1.206	5.113	11.102
$Capital$	4.483	0.166	4.297	4.787
$Labour$	4.045	0.261	3.738	4.585
$Fuel$	14.700	1.190	10.606	16.473
age	9.774	7.050	1	21
$ownership$			0	1
Isolated power plants - Total number of observations				
$Output$	4.379	1.617	1.118	7.894
$Capital$	-0.287	0.817	-1.022	1.946
$Labour$	1.705	0.456	1.386	3.135
$Fuel$	10.408	1.363	8.089	13.535
age	6.512	4.789	1	27
$grid$			0	1

Source: Author’s estimation from ERC data.

Table B.11: Malmquist index summary of firm means

Plant Name	Technical Efficiency Change (CRS)		Technical change		Pure Technical efficiency change (VRS)		Scale efficiency change		Total factor productivity change	
	Combined	Separate (isolated /grid)	Combined	Separate (isolated/grid)	Combined	Separate (isolated /grid)	Combined	Separate (isolated/grid)	Combined	Separate (isolated /grid)
Lodwar	1.007	0.999	0.997	1.004	1.000	0.999	1.007	1.000	1.005	1.003
Mandera	1.005	1.000	1.002	1.005	1.000	1.000	1.005	1.000	1.007	1.005
Marsabit	1.004	0.994	0.991	1.002	1.000	0.994	1.004	1.000	0.995	0.995
Wajir	1.012	1.004	0.996	1.000	1.000	1.000	1.012	1.004	1.008	1.004
Merti	1.000	1.005	1.002	1.009	1.000	1.000	1.000	1.005	1.002	1.014
Habaswein	1.000	1.002	1.000	1.006	1.000	1.000	1.000	1.002	1.000	1.007
Elwak	1.000	1.000	1.003	1.006	1.000	1.000	1.000	1.000	1.003	1.006
Baragoi	1.000	1.000	0.999	1.004	1.000	1.000	1.000	1.000	0.999	1.004
Mfangano	1.000	1.000	1.003	1.005	1.000	1.000	1.000	1.000	1.003	1.005
Lokichogio	1.000	1.000	1.000	1.005	1.000	1.000	1.000	1.000	1.000	1.004
Takaba	1.000	1.000	1.000	1.006	1.000	1.000	1.000	1.000	1.000	1.006
Eldas	1.000	1.001	1.000	0.998	1.000	1.000	1.000	1.001	1.000	0.999
Rhamu	1.000	1.009	1.003	1.007	1.000	1.000	1.000	1.009	1.003	1.016
Laisamis	1.000	1.007	0.996	1.003	1.000	1.000	1.000	1.007	0.996	1.011
Tsavo	1.000	0.999	1.023	1.019	1.000	1.000	1.000	0.999	1.023	1.018
Rabai	1.000	1.000	0.997	0.997	1.000	1.000	1.000	1.000	0.997	0.997
Iberafrica	1.004	1.010	0.980	0.982	1.000	1.000	1.004	1.010	0.984	0.992
Thika	1.003	1.021	1.001	0.992	1.000	1.020	1.003	1.000	1.004	1.012
Triumph	1.002	1.024	1.036	0.999	1.000	1.024	1.002	1.000	1.038	1.022
Kipevu 3	1.016	1.015	0.993	0.979	1.000	1.000	1.016	1.015	1.009	0.994
Kipevu I	1.000	1.000	0.981	0.970	1.000	1.000	1.000	1.000	0.981	0.970
Average	1.002	0.999	1.000	1.004	1.000	0.999	1.002	1.000	1.003	1.003

Source: Author's estimation from ERC data

C. Appendix 3: Exploring drivers of electricity costs in Kenya

Table C.12: Average costs data summary statistics after logarithmic transformation

Log of Variable	Mean	Standard. Deviation	Maximum	Minimum
Average cost	1.562	0.595	2.322	0.770
Output	18.792	0.138	19.131	18.523
Load Factor	0.697	0.017	0.726	0.644
Price of Capital	8.305	0.383	8.849	7.650
Price of Labour	13.808	0.283	14.333	13.097
System Losses	0.175	0.026	0.227	0.129

Source: Author's estimates using KPLC annual report data

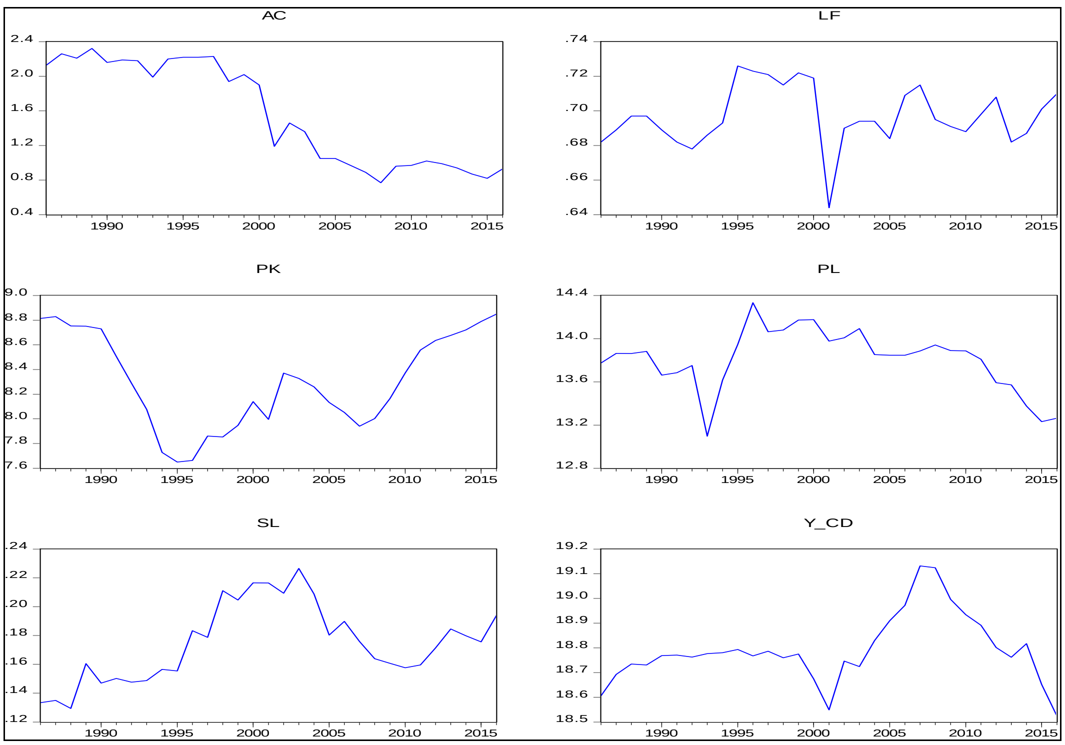

Figure C.1: Graphical presentation of the variables used in estimating the average cost

Source: Author's compilation using KPLC annual report data

Table C.13: Correlation matrix for the variables used in the estimation of average cost

	Average costs	Load Factor	Price of Capital	Price of Labour	System Losses	Output
Average costs	1.000	0.161	-0.148	0.270	-0.357	-0.388
Load Factor	0.161	1.000	-0.342	0.296	0.157	0.193
Price of Capital	-0.148	-0.342	1.000	-0.504	-0.317	-0.361
Price of Labour	0.270	0.296	-0.504	1.000	0.342	0.175
System Load Factor	-0.357	0.157	-0.317	0.342	1.000	-0.137
Output	-0.388	0.193	-0.361	0.175	-0.137	1.000

Source: Author's estimates using KPLC annual report data

Table C.14: Coefficient Variance Decomposition of the average cost model

Eigenvalues	9.187	1.377	0.592	0.374	0.007	0.004	0.002	0.001	0.000	0.000
Condition	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	1.000
Variance Decomposition Proportions										
	Associated Eigenvalue									
Variable	1	2	3	4	5	6	7	8	9	10
Average cost(-1)	0.024	0.586	0.000	0.009	0.332	0.009	0.032	0.000	0.007	0.000
Output	0.884	0.011	0.008	0.022	0.030	0.031	0.014	0.000	0.000	0.000
Price of Capital	0.582	0.003	0.000	0.002	0.036	0.012	0.142	0.221	0.001	0.000
Price of Labour	0.056	0.014	0.001	0.078	0.463	0.312	0.038	0.038	0.000	0.000
Load Factor	0.000	0.818	0.044	0.138	0.000	0.000	0.000	0.000	0.000	0.000
Load Factor(-1)	0.047	0.033	0.739	0.181	0.000	0.000	0.000	0.000	0.000	0.000
System Losses	0.348	0.441	0.106	0.105	0.000	0.000	0.000	0.000	0.000	0.000
Strategies	0.001	0.549	0.004	0.021	0.223	0.194	0.003	0.000	0.005	0.000
Reforms	0.101	0.285	0.013	0.206	0.039	0.174	0.159	0.014	0.007	0.000
Constant	0.996	0.003	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000

Source: Author's estimates using KPLC annual report data

The decomposition proportions associated with the smallest condition number are located in the first column and indicated two variables are larger than 0.5, indicating output and price of capital could be collated. However, the Variance inflation factor tests indicates otherwise as presented in Table C.4.

Table C.15: Variance inflation factors for the average cost model

Variable	VIF
Load factor	2.495159
Load factor (-1)	1.485949
Price of Capital	2.518227
Price of Labour	2.275592
System Losses	7.223227
Output	3.516255

Source: Author's estimates using KPLC annual report data

Table C.16: Unit root tests for variable used to estimate the total cost

Variable	**Test**	**Intercept only**	**Intercept and Trend**	**Results**
Total Cost	ADF	-1.712812	-2.164828	The series are stationary at level at 1% level of significance based on the breakpoint unit root test; Trend and intercept - intercept.
	PP	-1.795879	-2.324434	
	KPSS	0.349123	0.098090	
	Breakpoint	-4.399987	-7.828318	
Output	ADF	-0.089866	-1.506001	The series are stationary at level at 1% level of significance based on the breakpoint unit root test; Trend and intercept - trend and intercept.
	PP	-0.127653	-1.736699	
	KPSS	0.725259	0.122893	
	Breakpoint	-3.223456	-9.173188	
Customer Density	ADF	3.082408	1.277596	The series are stationary at level at 10% level of significance based on the breakpoint unit root test; Intercept.
	PP	2.216747	0.448876	
	KPSS	0.670365	0.123551	
	Breakpoint	-4.283545	-3.655194	
System losses	ADF	-1.810361	-1.724127	The series are stationary at level at 10% level of significance based on the breakpoint unit root test; Intercept and at 5% for Trend and intercept, trend only.
	PP	-1.823426	-1.765146	
	KPSS	0.267246	0.145169	
	Breakpoint	-4.255751	-4.945066	
Load factor	ADF	-3.784367	-3.71767	The series are stationary at level at 1% level of significance based on the ADF, PP and breakpoint unit root test; Trend and intercept - trend and intercept.
	PP	-3.770010	-3.704217	
	KPSS	0.088748	0.084921	
	Breakpoint	-3.997779	-8.513490	
Price of Capital	ADF	-1.045931	-2.346089	The series are stationary at level at 1% level of significance based on the breakpoint unit root test: Trend and intercept - trend and intercept.
	PP	-1.531329	-1.326560	
	KPSS	0.165692	0.158962	
	Breakpoint	-4.863098	-6.536462	
Price of labour	ADF	-1.6910956	-1.9072234	The series are stationary at level at 1% level of significance based on the breakpoint unit root test: trend and intercept – intercept only
	PP	-1.6910956	-1.9027701	
	KPSS	0.2242067	0.151222	
	Breakpoint	-2.857157	-5.464668	

Source: Author's estimates using KPLC annual report data

Critical levels 1%, 5%, and 10% significance levels are as follows; Intercept ADF(-3.67017, 2.963972, - -2.621007), PP(-3.67017, -2.963972, -2.621007), KPSS(0.739000, 0.463000, 0.347000), Break point (-4.949133, -4.443649, -4.193627) Intercept and Trend ADF(-4.296729, -3.568379, -3.218382), PP (-4.296729, -3.568379, -3.218382), KPSS(0.216000, 0.146000, 0.119000) break point; Intercept (-5.347598, -4.859812, -4.607324) Trend and intercept (-5.719131, -5.175710, -4.893950); trend(-5.067425, -4.524826, -4.261048).

Table C.17: Model selection for the total cost function

Model	Akaike Information Criteria*
ARDL (1, 0, 1, 0, 0, 0, 0)	-2.58447
ARDL (1, 0, 1, 0, 0, 0, 1)	-2.54903
ARDL (1, 0, 1, 0, 0, 1, 0)	-2.53222
ARDL (1, 1, 1, 0, 0, 0, 0)	-2.51945
ARDL (1, 0, 1, 1, 0, 0, 0)	-2.51883

Source: Author's estimates using KPLC annual report data

Table C.18: Residual and stability test for the total cost function model

Description	LM serial correlation	Normality	Heteroskedasticity	CUSUM and CUSUM of squares	Conclusion
No intercept no trend model	0.1284	0.3871	0.7701	within the confines of the 5% significance	Diagnostic tests passed
Intercept and no trend model	0.3063	0.394	0.6229	within the confines of the 5% significance	Diagnostic tests passed
Intercept with trend model	0.4244	0.4512	0.8956	within the confines of the 5% significance	Diagnostic tests passed

Source: Author's estimates using KPLC annual report data

Table C.19: Bounds cointegration test for the total cost model

Description	Critical Values		F statistics	Conclusion
No Constant and No Trend	I (0)	I (1)	19.03058	Long run relationship exists
	1.75(10%)	2.87(10%)		
	2.04(5%)	3.24(5%)		
	2.66(1%)	4.05(1%)		
Intercept and no trend model	I (0)	I (1)	20.077	Long run relationship exists
	2.12(10%)	3.23(10%)		
	2.45(5%)	3.61(5%)		
	3.15(1%)	4.43(1%)		
Intercept with trend model	I (0)	I (1)	19.520	Long run relationship exists
	2.53(10%)	3.59(10%)		
	2.87(5%)	4(5%)		
	3.6(1%)	4.9(1%)		

Source: Author's estimates using KPLC annual report data